disturbance.[251] While some commenters agree with this proposal, APPA and Xcel express concerns regarding the scope and applicability of some of the Requirements of the Reliability Standard.

612. Requirement R2 of the Reliability Standard requires reliability coordinators, balancing authorities, transmission operators, generator operators and LSEs to promptly analyze disturbances on their system or facilities. APPA is concerned that generator operators and LSEs may be unable to promptly analyze disturbances, particularly those disturbances that may have originated outside of their systems, as they may have neither the data nor the tools required for such analysis. The Commission understands APPA's concern and believes that, at a minimum, generator operators and LSEs should analyze the performance of their equipment and provide the data and information on their equipment to assist others with their analyses. The Commission directs the ERO to consider this concern in future revisions to the Reliability Standard through the Reliability Standards development process.

613. The Commission disagrees with Xcel that the Reliability Standard is unclear about what constitutes a reportable event. Attachment 1 of the Reliability Standard details the various events that would trigger the reporting requirement under this Reliability Standard.

614. FirstEnergy states that since nuclear units have their own NRC reporting requirements the Reliability Standard should specify that compliance with NRC procedures is sufficient to satisfy the obligations of this Reliability Standard. The Commission disagrees with FirstEnergy because there are situations where the ERO Reliability Standards are more stringent than the NRC procedures. In such cases, the ERO Reliability Standards must apply in addition to the NRC requirements. Also, the Commission disagrees with FirstEnergy's comment on changing this Reliability Standard's name to avoid confusion with BAL-002-0. The purpose of the Reliability Standard is clear as to the extent of the disturbances to be reported.

615. The Commission declines to address Xcel's concerns about the current WECC process. These issues should be addressed in the Reliability Standards development process or submitted as a regional difference. The Commission directs the ERO to consider all comments in future modifications of the Reliability Standard through the Reliability Standards development process.

[251] NOPR at P 304.

616. In response to APPA's concern that NERC did not provide a Measure for each Requirement, we reiterate that it is in the ERO's discretion whether each Requirement requires a corresponding Measure. The ERO should consider this issue through the Reliability Standards development process.

617. While the Commission has identified concerns with regard to EOP-004-1, we believe that the proposal serves an important purpose in establishing requirements for reporting and analysis of system disturbances. Accordingly, the Commission approves Reliability Standard EOP-004-1 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to EOP-004-1 through the Reliability Standards development process that includes any Requirements necessary for users, owners and operators of the Bulk-Power System to provide data that will assist NERC in the investigation of a blackout or disturbance

618. Requirement R3 addresses the reporting of disturbances to the regional reliability organizations and NERC. The Commission directs the ERO to change its Rules of Procedure to assure that the Commission also receives these reports within the same time frames as DOE.

e. System Restoration Plans (EOP-005-1)

619. EOP-005-1 deals with system restoration plans and requires that plans, procedures, and resources be available to restore the electric system to a normal condition in the event of a partial or total system shut down. The Reliability Standard requires transmission operators, balancing authorities, and reliability coordinators to have effective restoration plans, to test those plans, and to be able to restore the interconnection using them following a blackout. It also requires operating personnel to be trained in these plans.

620. In the NOPR, the Commission proposed to approve Reliability Standard EOP-005-1 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission proposed to direct that NERC submit a modification to EOP-005-1 that: (1) includes Measures and (2) identifies time frames for training and review of restoration plan requirements to simulate contingencies and prepare operators for anticipated and unforeseen events.

i. Comments

621. APPA and EEI state that Reliability Standard EOP-005-1 is sufficient for approval as a mandatory Reliability Standard and requests that the Commission direct NERC to address missing Measures and training requirements. In addition, APPA notes that the Reliability Standard is applicable to both balancing authorities and transmission operators

but the Measures and Levels of Non-Compliance elements refer only to transmission operators.

622. ISO-NE does not support adoption of the proposed Reliability Standard because, while Requirement R1 requires transmission operators to include applicable elements from Attachment 1 of EOP-005-1 in their restoration plans, Requirement R1 appears to indicate that the elements in Attachment 1 are to be included in the emergency plan only "as applicable." ISO-NE states that the Reliability Standard should be clarified to indicate that the actual emergency plan elements should be the basis for compliance.

623. EEI and FirstEnergy note that the proposed modification to identify time frames for training and review of restoration plan requirements is being addressed in the proposed Reliability Standard PER-005-1 and that including this requirement in EOP-005-1 would be redundant. MISO also believes that the proposed modification is unnecessary. It states that there are already requirements for simulation-based training on emergencies and restoration and it is unclear what is meant by conducting training to prepare operators for unforeseen events.

624. FirstEnergy states that Requirement R1 calls for a plan for a partial shutdown of the system and that there is an infinite set of events that can cause a partial shutdown. According to FirstEnergy, because the borders of a partial shutdown are difficult, if not impossible, to foresee, the Reliability Standard should specify some boundaries for analysis of partial shutdowns including an appropriate definition of the term "partial shutdown." In addition, FirstEnergy states that one uniform plan for all systems is not feasible; rather the Reliability Standard should recognize that some companies already have existing plans that could be used for analyzing events. FirstEnergy also states that the Reliability Standard should provide a uniform checklist of factors to analyze, developed on a company-specific basis.

625. NRC suggests that this Reliability Standard include: (1) a requirement to record the time it takes to restore power to the auxiliary power systems of nuclear power plants; (2) a provision stating that the affected transmission operators shall give high priority to restoration of off-site power to nuclear power plants whether or not a nuclear power plant is being powered from the nuclear power plant's onsite power supply and (3) a provision stating that restoration shall not violate nuclear power plant minimum voltage and frequency requirements.

626. While not commenting on the substance of Reliability Standard EOP-005-1, MRO states that EOP-005-1, EOP-006-1 and EOP-007-0 are ordered in a confusing manner and should be renumbered. MRO reasons that since the regional coordinator has oversight responsibility for system restoration, EOP-006-1 should be first in the system restoration sequence of Reliability Standards (i.e., EOP-006-1 should precede EOP-005-1). Further,

MRO recommends that EOP-005-1 follow EOP-006-1 because transmission owners and balancing authorities are responsible for submitting restoration plans to the regional coordinator. MRO requests that if a reason exists for the current order, NERC should provide that reason to the Commission.

ii. Commission Determination

627. With regard to comments that the Commission's concerns are being addressed in NERC's drafting of proposed PER-005-1 Reliability Standard on operator training, we note PER-005-1 only includes Requirements on the control room personnel and not those outside of the control room. System restoration requires the participation of not only control room personnel but also those outside of the control room. These include blackstart unit operators and field switching operators in situations where SCADA capability is unavailable. As such, the Commission believes that inclusion of periodic system restoration drills and training and review of restoration plans in a system restoration Reliability Standard is the most effective way of achieving the desired goal of ensuring that all participants are trained in system restoration and that the restoration plans are up to date to deal with system changes.

628. Several commenters raise issues that should be addressed by the ERO through the Reliability Standards development process.[252] For example: whether the Measures and Levels of Non-Compliance should refer to balancing authorities; clarification of the elements that form the basis for compliance with the requirements of Attachment 1; what constitutes a partial shutdown for which restoration plans must be developed and recognition that some companies already have existing plans that could be used for analyzing events; and that the Reliability Standard should provide a uniform checklist of factors to analyze, developed on a company-specific basis. We find that consideration of these issues could be helpful in meeting the objectives of the Reliability Standard. Accordingly, the ERO should consider these concerns in future revisions of the Reliability Standard through the Reliability Standards development process.

629. NRC raises several issues concerning the role and priority that nuclear power plants should have in system restorations. The Commission shares these concerns and directs the ERO to consider the issues raised by NRC in future revisions of the Reliability Standard through the Reliability Standards development process. In addition the Commission directs the ERO to gather data, pursuant to § 39.5(f) of the Commission's regulations, from simulations and drills of system restoration on the time it takes to

[252] See APPA, ISO-NE, FirstEnergy and MRO.

restore power to the auxiliary power systems of nuclear power plants under its data gathering authority and report that information to the Commission on a quarterly basis.

630. We find that the Reliability Standard adequately addresses operating personnel training and system restoration plans to ensure that transmission operators, balancing authorities and reliability coordinators are prepared to restore the Interconnection following a blackout. Accordingly, the Commission approves Reliability Standard EOP-005-1 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to EOP-005-1 through the Reliability Standards development process that identifies time frames for training and review of restoration plan requirements to simulate contingencies and prepare operators for anticipated and unforeseen events and gathers the data from simulations and drills of system restoration on the time it takes to restore power to the auxiliary power systems of nuclear power plants under its data gathering authority and report that information to the Commission on a quarterly basis.

f. Reliability Coordination-System Restoration (EOP-006-1)

631. Proposed Reliability Standard EOP-006-1 addresses reliability coordination and system restoration.[253] It establishes specific requirements for reliability coordinators during system restoration, and it states that reliability coordinators must have a coordinating role in system restoration to ensure that reliability is maintained during restoration and that priority is placed on restoring the Interconnection.

632. In the NOPR, the Commission proposed to approve the Reliability Standard as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission proposed to direct that NERC submit a modification to the Reliability Standard that: (1) requires that the reliability coordinator be involved in the development of and approves restoration plans and (2) includes Measures and Levels of Non-Compliance.

i. Comments

633. APPA states that Reliability Standard EOP-006-1, which NERC filed on November 15, 2006, includes the required Measures and Levels of Non-Compliance and

[253] In its November 15, 2006, filing, NERC submitted EOP-006-1, which supercedes the Version 0 Reliability Standard. EOP-006-1 adds Measures and Levels of Non-Compliance to the Version 0 Reliability Standard. In this Final Rule, we review the November version, EOP-006-1.

as such APPA agrees that EOP-006-1 should be approved as mandatory and enforceable. In addition, APPA does not oppose industry consideration of a requirement that reliability coordinators be involved in the development and approval of restoration plans.

634. EEI states that Requirements R4 and R11 of EOP-005-1 already address reliability coordinator involvement in the development and approval of transmission operator system restoration plans. Further, while EEI agrees that the reliability coordinator's role is appropriate, it believes that the asset owner, as the entity that ultimately bears responsibility for restoration capabilities, should also have authority to develop and maintain the plans. MISO believes that it is unnecessary to modify the Reliability Standard to involve the reliability coordinator because there is already a requirement in EOP-005-1 for balancing authorities and transmission operators to coordinate their plans with the reliability coordinator.

635. Xcel disagrees that the reliability coordinator should be involved with the development of restoration plans because the reliability coordinator typically does not have the knowledge of the details necessary to develop the plans in contrast to the balancing authorities and the transmission operators. Instead it proposes that the reliability coordinator develop its own plans and coordinate that with the balancing authority and transmission operator's plans.

ii. Commission Determination

636. The reliability coordinator is the highest level of authority that is responsible for the reliable operation of the Bulk-Power System. Given the importance of this role in connection with matters covered by EOP-006-1, the Commission believes that the reliability coordinator must be involved in the development and approval of the restoration plans. The current Reliability Standard only requires that the reliability coordinator be aware of the restoration plan of each transmission operator in its area. The Commission disagrees with EEI and MISO who contend that the reliability coordinator's role in the transmission operator's restoration plan is covered in EOP-005-1. EOP-005-1 only requires coordination with the reliability coordinator, and during actual system restoration, EOP-005-1 requires approval from the reliability coordinator to resynchronize isolated areas with other isolated areas.

637. In response to comments by Xcel, the Commission believes that while the reliability coordinator may not have the level of detailed knowledge that the balancing authorities and transmission operators may have for setting-up the stable islands required under restoration plans, the reliability coordinator is in the best position to determine how those stable islands should be resynchronized with each other and the rest of the interconnected system.

638. The Commission finds that the Reliability Standard adequately addresses the goals of effective and efficient reliability coordination and system restoration. Accordingly, the Commission approves Reliability Standard EOP-006-1 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to EOP-006-1 through the Reliability Standards development process that ensures that the reliability coordinator, which is the highest level of authority responsible for reliability of the Bulk-Power System, is involved in the development and approval of system restoration plans.

g. Establish, Maintain, and Document a Regional Blackstart Capability Plan (EOP-007-0)

639. EOP-007-0, which deals with establishing, maintaining and documenting regional blackstart capability plans, ensures that the quantity and location of system blackstart generators are sufficient and that they can perform their expected functions as specified in the overall coordinated regional system restoration plans.

640. The NOPR did not propose to approve or remand EOP-007-0, because it applies only to regional reliability organizations.

i. Comments

641. APPA agrees that EOP-007-0 should not be approved as a mandatory Reliability Standard and states that in the interim the regional reliability organizations and Regional Entities should continue to perform this function. In addition, APPA proposes that, in the interim, an umbrella organization composed of representatives from each regional reliability organization and Regional Entity should be formed to establish operation planning rules, including blackstart requirements, across the Eastern Interconnection. APPA suggests that such an effort would go a long way in identifying critical facilities, using consistent and transparent study assumptions and minimizing seams during system emergencies throughout the Interconnection.

642. TANC states that the number of blackstart units and their locations depend heavily on regional characteristics and cannot be prescribed in a uniform, continent-wide manner. It proposes that regional flexibility be afforded to provide an appropriate mix of facilities to achieve the reliability objectives. EEI suggests that EOP-007-0 be rewritten so that compliance obligations are assigned directly to those entities that provide the data and other information.

643. FirstEnergy and MRO state that the reliability coordinator, not the Regional Entity, should be responsible for the regional blackstart plan for its area of responsibility. Further, FirstEnergy states that the blackstart plan developed for a region should be

consistent with NRC requirements, should recognize that nuclear units have no blackstart capability and should recognize that nuclear units must have priority access to off-site power for safety reasons. FirstEnergy requests that the Commission direct NERC to revise the definition of a blackstart unit to mean a "diesel, hydro, pump storage, or the combustion turbine generating unit that is used to provide cranking power to a larger steam generating unit designed to restore load" or to mean a "larger steam generating unit designed to restore load."[254] MRO states that arrangements for coordination of blackstart capability should be addressed in a contract between appropriate entities.

ii. Commission Determination

644. The Commission will not approve or remand EOP-007-0, because it applies only to regional reliability organizations. However, the Commission provides guidance for the ERO's future consideration.

645. The Commission disagrees with APPA that an umbrella organization is needed for the Eastern Interconnection while the Reliability Standard is pending final approval. The Commission is persuaded that FirstEnergy's and MRO's comments concerning the reliability coordinator being responsible for regional blackstart plans have merit. The Commission has directed that the reliability coordinator approve the system restoration plans and this is a logical extension of that direction. However, until such time as the Reliability Standard has been revised and approved by the ERO and the Commission, the regional reliability organization (or Regional Entity, depending on the organization of a particular region) should continue to perform this role as it has in the past.[255]

646. With regard to TANC's request for regional flexibility in determining the appropriate mix of facilities needed to achieve the reliability objectives, it is our understanding that the Reliability Standard provides for the number and location of blackstart units to vary depending on the specific requirements of each system. We believe that uniformity will be required, however, in the criteria used to determine the number and location of blackstart units and testing requirements.

647. EEI, FirstEnergy and MRO offer suggestions for improving the Reliability Standard. The Commission directs the ERO to consider these suggestions in future revisions to improve EOP-007-0, through the Reliability Standards development process.

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[254] See FirstEnergy at 35.

[255] See NOPR at P 328.

648. Accordingly, the Commission will not approve or remand EOP-007-0 at this time.

h. Plans for Loss of Control Center Functionality (EOP-008-0)

649. EOP-008-0 addresses plans for loss of control center functionality. It requires each reliability coordinator, transmission operator and balancing authority to have a plan to continue reliable operations and to maintain situational awareness in the event its control center is no longer operable.

650. The Commission proposed five modifications to the Reliability Standard and requested additional comments on other issues. We have grouped the comments into two general categories: (1) capabilities of backup control centers and (2) which entities should have full backup centers. Below, we address each topic separately, followed by an over-all conclusion and summary.

i. Capabilities of backup control centers

651. In the NOPR, the Commission proposed to approve Reliability Standard EOP-008-0 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission proposed to direct that NERC submit a modification to EOP-008-0 that includes a Requirement that provides for backup capabilities that, at a minimum, must: (1) be independent of the primary control center; (2) be capable of operating for a prolonged period of time and (3) provide for a minimum set of tools and facilities to replicate the critical reliability functions of the primary control center.[256] In addition to these three capabilities requirements, the Commission solicited comments concerning other specific capabilities.

(a) Comments

652. EEI, Entergy, FirstEnergy and Northern Indiana support the proposed modifications to EOP-008-0. Entergy agrees with the Commission's proposed modifications to include more Requirements regarding backup capabilities.

653. APPA, Nevada Companies and TAPS caution that costs must be considered and compared to possible benefits. APPA states that it would take some time to implement the proposed modifications and therefore specific requirements for backup control

[256] The term "facility" in this context includes, but is not limited to, telecommunications, backup power supplies, computer systems and security systems. NOPR at P 335 & n.159.

facilities and capabilities should be left to the Reliability Standard development process. Nevada Companies cautions that utilities that have invested millions of dollars in back-up capabilities may find these facilities to be non-compliant with the proposed Reliability Standard. It suggests that cost/benefits analyses be conducted and that a grandfathering provision be adopted to protect investments in backup systems that were made in a good faith effort to comply with rules in place in the past, but which may not comply with the Reliability Standard.

654. MRO requests clarification of the term "capability" because it is unsure if the term is intended to refer to a facility, what such a facility should consist of and what operators should be capable of doing from that facility.

655. In response to the request for comments on backup capabilities, NERC states that these are best addressed through the Reliability Standards development process.

656. SoCal Edison suggests that a risk-based assessment be considered to determine the requirements for backup. MISO, TAPS and International Transmission note that work is underway by NERC to address the provisions for redundancy and backup control capabilities via the Operating Committee Backup Control Task Force and that the focus is on functionality rather than physical requirements. TAPS states that, rather than directing NERC to adopt specific modifications to the Reliability Standard that would inappropriately burden small systems with the cost of dual facilities, the Commission should identify objectives to the Task Force. TAPS also states that a small balancing authority might be able to meet the functional requirements for a backup control center with a contract with another entity while larger entities might need a physical backup center.

657. Northern Indiana states that the Commission's proposal appears to eliminate an entity's opportunity to contract for backup capabilities from others who already have full backup control centers. FirstEnergy and Northern Indiana advocate for flexibility in the means used to meet the backup requirements and request that the Commission clarify that a "full backup center" can include providing full redundancy by contract rather than physical backup center facilities. SoCal Edison states that when entities utilize the services of another entity for backup, they should be required to test the backup capability a minimum number of times during the year and that all system operators should be required to participate in such testing over a specified time period.

658. NRC suggests that this Reliability Standard require: (1) a list of the nuclear power plants and their voltage, thermal, and/or frequency limits and (2) provisions to notify nuclear power plants of the loss of control center functionality.

(b) Commission Determination

659. As we stated in the NOPR, the goal of the Reliability Standard is the continuation of reliable operations and the maintenance of situational awareness in the event that the primary control center is no longer operational.[257] Some commenters support the proposal to require backup capabilities while others including APPA, Nevada Companies and TAPS caution that the cost of the proposal may not be justified. In addition, some commenters, including FirstEnergy and Northern Indiana, advocate for flexibility in meeting the backup requirements and suggest that entities should be able to contract for full redundancy. MRO seeks clarification regarding the use of the term "capability."

660. In the NOPR, we found that the provision of backup capabilities should be an explicit Requirement to meet the objectives of the Reliability Standard. We chose to use the word "capabilities" to avoid defining particular facilities or preclude other options, including arranging for backup capabilities by contracting with others. We stated that the mechanism to provide these capabilities may include building fully redundant physical backup control centers, contracting for backup control services or using backup equipment within a separate existing facility.[258] In addition, regardless of the means used to provide the backup capabilities, as we stated in the NOPR, the time period for which backup capability is required should correspond to the time it would take to replace the primary control center.

661. On the issue of additional backup capabilities, NERC, MISO, TAPS and International Transmission propose that the functional requirements for backup capabilities be determined by the NERC Backup Control Task Force. NRC offers requirements it believes should be added to the Reliability Standard.

662. The Commission disagrees with the Nevada Companies' proposal for grandfathering. The Reliability Standards must define the minimum functions that are necessary for the Reliable Operation of the Bulk-Power System. The flexibility described above on how capabilities are provided should mitigate any costs incurred to upgrade older centers.

663. Given the importance to reliability of maintaining situational awareness in the event of loss of the primary control center operations, the Commission believes that, at a minimum, the three requirements — independence from the primary control center,

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[257] NOPR at P 329.

[258] See Id. at P 336.

capability to operate for a prolonged period corresponding to the time it would take to replace the primary control center, and the provision of a minimum set of tools and facilities to replicate the critical reliability functions of the primary control center – must be included as explicit requirements in the Reliability Standard. Other additional Requirements may be developed by the Backup Control Task Force for inclusion in the Reliability Standard. The Commission directs the ERO to develop modifications to the requirements in future revisions to the Reliability Standard through the Reliability Standards development process.

ii. Which entities should have full backup centers

664. In the NOPR , the Commission proposed to direct that NERC submit a modification to EOP-008-0 that: (1) provides that the extent of the backup capability be consistent with the impact of the loss of the entity's primary control center on the reliability of the Bulk-Power System and (2) includes a Requirement that all reliability coordinators have full backup control centers. The Commission also requested comments on what other entities, such as balancing authorities and large transmission operators, should have full backup centers.

(a) Comments

665. International Transmission, MISO and FirstEnergy state that in addition to reliability coordinators, large balancing authorities and transmission operators need full backup control centers. MISO states that there are certain situations where large generation fleets that are controlled centrally would also warrant full backup systems and that small entities can operate reliably with less robust systems. Further, it argues that the ERO needs latitude to decide from a reliability standpoint how much redundancy is needed. FirstEnergy states that in place of full backup control facilities it should be acceptable to have standing contracts in place to provide backup services in the event of a loss of a control center.

666. NERC states that the proposed directive presumes that the only way to achieve highly reliable and independent backup capability to perform reliability coordinator functions in an emergency is to have a redundant control center. NERC contends that while this may be an option, it may not be the only one for achieving the necessary reliability objective. NERC proposes that the Reliability Standard be modified to define the performance results expected rather than how an entity should meet the requirements.

667. NERC, SoCal Edison and Otter Tail state that the question of what other entities should have full backup centers is best addressed through the Reliability Standards development process. Otter Tail requests that the Commission not require all balancing authorities to have full backup centers since the loss of a small balancing authority's

control center would not have a substantial impact on the reliability of the Bulk-Power System. Northern Indiana states that requiring transmission operators and balancing authorities to have full backup centers would result in significant unnecessary facility duplication, at great cost to consumers, and without a material increase in reliability.

668. FirstEnergy comments that the Reliability Standard should not require a fully redundant SCADA system for the backup control center for balancing authorities or transmission operators because the cost would be prohibitive. It states that balancing authorities, transmission operators and centrally-located generation owners should be permitted to have a single distributed computer system in place to diminish the probability of a complete system shutdown due to a natural disaster or a single man-made physical act of sabotage.

669. Nevada Companies also questions whether the significant cost of full replication could ever be cost-effective, especially considering the very high level of control center reliability achieved now with the existing solution of a single control center plus backup of critical systems.

(b) Commission Determination

670. Several commenters agree with the Commission that reliability coordinators at a minimum should have full backup control centers. They also propose that this requirement be extended to large balancing authorities, transmission operators and centrally dispatched generation facilities. Others caution on the cost implications of requiring full duplication given the very high level of control center reliability achieved with the existing technology and backup of critical systems. Having carefully considered all the issues raised by commenters and taking into account the reliability impacts of loss of primary control centers and the role of reliability coordinators as the highest level of authority responsible for reliability of the Bulk-Power System, the Commission is persuaded that all reliability coordinators must have fully redundant independent backup control centers. In response to NERC, any proposed modification that is independent from the primary center, provides for continuous monitoring and has the full functionality of the primary center would satisfy our concerns. Other entities, including balancing authorities, transmission operators and centrally dispatched generation control centers, must provide for the minimum backup capabilities discussed above but may do so through other means, such as contracting for these services instead of through dedicated backup control centers.

671. In addition, in response to FirstEnergy's concern regarding balancing authorities and transmission operators having fully redundant SCADA systems and distributed computer systems, the Commission requires the primary and backup capabilities to replicate critical reliability functionalities and be independent from the primary control

center, including telemetered data and control from remote terminal units. This can be achieved through a variety of design alternatives, e.g., developing a SCADA management platform that will allow telemetered data and control to be shared among SCADA systems so that data and control is not lost during a SCADA or communications failure.. The Commission's focus is on function, not design.

iii. Summary of Commission Determination

672. Accordingly, the Commission approves Reliability Standard EOP-0081-0 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to EOP-008-0 through the Reliability Standards development process that includes a Requirement that provides for backup capabilities that, at a minimum, must: (1) be independent of the primary control center; (2) be capable of operating for a prolonged period of time, generally defined by the time it takes to restore the primary control center; (3) provide for a minimum functionality to replicate the critical reliability functions of the primary control center; (4) provides that the extent of the backup capability be consistent with the impact of the loss of the entity's primary control center on the reliability of the Bulk-Power System; (5) includes a Requirement that all reliability coordinators have full backup control centers and (6) requires transmission operators and balancing authorities that have operational control over significant portions of generation and load to have minimum backup capabilities discussed above but may do so through contracting for these services instead of through dedicated backup control centers.

i. Documentation of Blackstart Generating Unit Tests Results (EOP-009-0)

673. Proposed Reliability Standard EOP-009-0 deals with documentation of blackstart generating unit test results. In the NOPR, the Commission proposed to approve EOP-009-0 as mandatory and enforceable without modifications.

i. Comments

674. APPA agrees that EOP-009-0 is sufficient for approval as a mandatory and enforceable Reliability Standard. Xcel states that the Reliability Standard should provide details on what constitutes a blackstart test and FirstEnergy states that EOP-009-0 should be consolidated with EOP-007-0 because the Requirements of EOP-009-0 already exist in EOP-007-0.

ii. Commission Determination

675. The Commission believes that this Reliability Standard sufficiently addresses documentation of blackstart generating unit test results. Accordingly, the Commission approves Reliability Standard EOP-009-0 as mandatory and enforceable.

676. Two commenters made suggestions for improving the Reliability Standard. The Commission directs the ERO to take these suggestions into consideration when revising the Reliability Standard through the Reliability Standards development process.

5. FAC: Facilities Design, Connections, Maintenance, and Transfer Capabilities

677. The nine Facility (FAC) Reliability Standards address topics such as facility connection requirements, facility ratings, system operating limits and transfer capabilities. The FAC Reliability Standards also establish requirements for maintaining equipment and rights-of-way, including vegetation management. The NOPR provided direction for seven of the nine FAC Reliability Standards; NERC withdrew two others, Reliability Standards FAC-004-0 and FAC-005-0. NERC, in its November 15, 2006 filing requests approval of three additional FAC Reliability Standards: FAC-010-0, FAC-011-0 and FAC-014-0. These Reliability Standards are being addressed in a separate docket.

a. Facility Connection Requirements (FAC-001-0)

678. Proposed Reliability Standard FAC-001-0 is intended to ensure that transmission owners establish facility connection and performance requirements to avoid adverse impacts to the Bulk-Power System. In the NOPR, the Commission proposed to approve FAC-001-0 as mandatory and enforceable.

i. Comments

679. APPA agrees with the Commission's proposal to approve FAC-001-0 as mandatory and enforceable.

ii. Commission Determination

680. As discussed in the NOPR, the Commission believes that Reliability Standard FAC-001-0 is just, reasonable, not unduly discriminatory or preferential and in the public interest and approves it as mandatory and enforceable.

b. Coordination of Plans for New Generation, Transmission, and End-User Facilities (FAC-002-0)

681. Proposed Reliability Standard FAC-002-0 requires that each generation owner, transmission owner, distribution provider, LSE, transmission planner and planning authority assess the impact of integrating generation, transmission and end-user facilities into the interconnected transmission system.

682. In the NOPR, the Commission proposed to approve Reliability Standard FAC-002-0 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission proposed to direct that NERC submit a modification to FAC-002-0 that amends Requirement R1.4 to require evaluation of system performance under both normal and contingency conditions by referencing TPL-001 through TPL-003.

i. Applicability and Assessment Responsibility

(a) Comments

683. APPA, Xcel and FirstEnergy state that this Reliability Standard is not clear about who will perform the required assessment and how many assessments are required under this Reliability Standard. APPA requests that the Reliability Standard be clarified to state that the required assessment must be performed only by the transmission planner and the planning authority. Xcel requests that the Commission clarify that only one required assessment needs to be done when new facilities are added, and that all the listed entities should participate in that single assessment.

684. FirstEnergy requests that NERC clarify what is considered a new facility and asks if, for example, up-rates should be included as new facilities. MRO is concerned that the impact of the Commission's directive is too broad and may have a substantial affect on those individual entities that are responsible for performing the studies; MRO asks the Commission to clarify FAC-002-0 to the extent necessary, but does not propose a specific change.

685. Six Cities requests that this Reliability Standard clarify that all applicable entities must make available data necessary for all other responsible entities to perform the required assessment. Six Cities also suggests that the transmission operator be added as an entity to which this Reliability Standard is applicable, at least from the perspective that it make necessary data available to all other entities responsible for assessment. TAPS believes that this Reliability Standard seems to assume that the LSE and distribution provider actively participate in planning of new facilities in the Bulk-Power System. TAPS states that very few LSEs or distribution providers have the expertise to perform

the tasks outlined in this Reliability Standard and that these two entities provide only certain data regarding certain new facilities to some or all of the other entities identified in this Reliability Standard. TAPS therefore believes that it would be unreasonable to require LSEs to provide the transmission planning evaluations and assessments called for by R1. California Cogeneration believes that the Reliability Standard implies that generator owners will perform an independent assessment and if so, it believes that such task is impossible, since generators do not have the relevant information about the power system to perform such evaluations. California Cogeneration believes that the Reliability Standard should be clarified so that generator owners cooperate with and provide input to the assessment performed by the transmission operator and the balancing authority.

686. FirstEnergy states that both MISO and PJM already have Large Generator Interconnection Procedures (LGIP) in place that provide a formal process that meets the requirements listed under R1, and asks that the Commission state that complying with the interconnection agreement and/or OATT satisfies this requirement. MISO states that their procedures for coordinating plans for new generation, transmission and end-user facilities includes modeling of normal system and contingency conditions.

(b) Commission Determination

687. All of the above commenters request clarification of Requirement R1 in the Reliability Standard that states that various functional entities "shall each coordinate and cooperate on its assessments with its transmission planner and planning authority."[259] The Commission believes that all entities listed in the Applicability section have a stake in the performance of the system and should have the opportunity to provide input in the assessment under R1. The Commission believes that commenters have raised valid concerns that, if addressed, would make the Reliability Standard better. The wording would allow a number of organizational approaches to achieving the goal of performing an analysis. The Commission does not intend to limit which organizational approach is used by the entities, only to assure that a single competent and collaborative analysis is performed. Therefore, the Commission directs the ERO to address these concerns in the Reliability Standards development process.

688. FirstEnergy asks the Commission to state that complying with MISO's and PJM's interconnection agreements and/or OATT satisfies requirement R1 under this Reliability Standard. We will not make that determination here. If FirstEnergy believes that complying with the MISO and PJM interconnection procedures meets the applicable

[259] FAC-002-0.

Reliability Standards, then it should follow those procedures, it should not be concerned about violating the Reliability Standard.

ii. Standards of Conduct

(a) Comments

689. Xcel and MidAmerican believe that the assessment required under this Reliability Standard may conflict with the Commission's Standards of Conduct[260] since the assessment requires coordination among several different functional groups within a vertically integrated public utility. MidAmerican asserts that, since direct communication between the generation and transmission entities would result in more efficient overall planning, the Commission should clarify its intended application of Standards of Conduct restrictions on joint planning activities. Xcel asks the Commission to clarify that actions taken to comply with this Reliability Standard will not result in a transmission provider being in violation of the Standards of Conduct.

(b) Commission Determination

690. The Commission disagrees with MidAmerican and Xcel that this Reliability Standard may conflict with the Standards of Conduct. This type of system assessment is being performed today with the cooperation of the entities listed in the Applicability section. Further, we note that the Standards of Conduct were designed to address such interactions. The entities participating in the assessment effort can continue to contribute to this assessment and observe the Standards of Conduct at the same time. If any entity finds an area where it believes the Standards of Conduct prevent it from cooperating with the assessment process, it may seek clarification from the Commission as to whether that area of involvement is in conflict with the Standards of Conduct.

iii. Reference to TPL Reliability Standards

(a) Comments

691. While APPA and EEI agree with the Commission's proposal to direct NERC to submit a modification to FAC-002-0 that amends Requirement R1.4 to require evaluation

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[260] Standards of Conduct for Transmission Providers, Order No. 2004, FERC Stats. & Regs., Regulations Preambles ¶ 31,155 (2003), order on reh'g, Order No. 2004-A, III FERC Stats. & Regs. ¶ 31,161 (2004), order on reh'g, Order No. 2004-B, III FERC Stats & Regs. ¶ 31,166 (2004).

of system performance under both normal and contingency conditions by referencing TPL-001-0 through TPL-003-0, Entergy disagrees and proposes that evaluation of system performance under Reliability Standards TPL-001-0 and TPL-002-0 should be sufficient. Entergy states that given the large number of small end-user requests that transmission operators may receive, expanding the scope of Requirement R1.4 may lead to additional work and documentation that ultimately will not benefit reliability. First Entergy states that the proposed reference to TPL Reliability Standards should be expanded to include TPL-001-0 through TPL-004-0.

(b) <u>Commission Determination</u>

692. The Commission notes that APPA and EEI agree with the Commission's proposed directive to NERC to modify FAC-002-0 to require evaluation of system performance under both normal and contingency conditions by referencing TPL-001-0 through TPL-003-0. The Commission also notes that NERC, in response to the Staff Preliminary Assessment, has also agreed with the same proposal.[261] These three TPL Reliability Standards cover normal operation, first contingency operation and multiple contingency operations respectively. The Commission disagrees with Entergy that TPL-001-0 and TPL-002-0 are sufficient because it is important to plan for new facilities taking into account not only normal circumstances but also contingencies. In addition, we note that including TPL-001-0 through TPL-003-0 will result in the FAC-002 Reliability Standard being consistent with Order No. 2003, which requires interconnecting entities to take into account multiple contingencies in interconnection studies. With respect to FirstEnergy's suggestion to also include a reference to Reliability Standard TPL-004-0, we direct the ERO to consider it through the Reliability Standards development process.

693. Accordingly, the Commission approves Reliability Standard FAC-002-0 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to FAC-002-0 through the Reliability Standards development process that amends Requirement R1.4 to require evaluation of system performance under both normal and contingency conditions by referencing TPL-001 through TPL-003. Further, the Commission also directs the ERO to consider the above commenters' concerns through the Reliability Standards development process.

[261] NOPR at P 352.

c. Transmission Vegetation Management Program (FAC-003-1)

694. According to NERC, FAC-003-1 is designed to minimize transmission outages from vegetation located on or near transmission rights-of-way by maintaining safe clearances between transmission lines and vegetation, and establishing a system for uniform reporting of vegetation-related transmission outages. FAC-003-1 would apply to transmission lines operated at 200 kV or higher voltage (and lower-voltage transmission lines which have been deemed critical to reliability by a regional reliability organization). It would require each transmission owner to have a documented vegetation management program in place, including records of its implementation. Each program must be designed for the geographical area and specific design configurations of the transmission owner's system.

695. This Reliability Standard requires a transmission owner to define a schedule for and the type (aerial or ground) of right-of-way vegetation inspections. In addition, it requires a transmission owner to determine and document the minimum allowable clearance between energized conductors and vegetation before the next trimming, and it specifically provides that "Transmission-Owner-specific minimum clearance distances shall be no less than those set forth in the IEEE Standard 516-2003 (IEEE Guide for Maintenance Methods on Energized Power Lines)."[262]

696. In the NOPR, the Commission proposed to approve Reliability Standard FAC-003-1 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission proposed to direct NERC to submit a modification to FAC-003-1 that: (1) requires the ERO develop a minimum vegetation inspection cycle that allows variation for physical differences and (2) removes the general limitation on applicability to transmission lines operated at 200 kV and above so that the Reliability Standard applies to Bulk-Power System transmission lines that have an impact on reliability as determined by the ERO.

i. Applicability

(a) Comments

697. Entergy agrees with the Commission's proposal and supports applying the Reliability Standard to only those lines that have an impact on reliability as determined

[262] FAC-003-1 (Requirement R1.2.2).

by the ERO, as supported by reliability studies using consistent reliability contingency criteria.

698. LPPC supports using an impact-based definition of the Bulk-Power System to determine applicability and suggests that the definition of significant adverse impact should be determined through the NERC process. Further, LPPC asserts that actual facilities meeting that criteria should be determined by Regional Entities, which best understand the impacts of facilities on the regional system. LPPC notes that Regional Entities can continue to use such tools as modeling and power flow analyses to determine which facilities are critical to the reliability of the Bulk-Power System.

699. APPA and Avista believe that Regional Entities should determine what transmission facilities this standard applies to, since Regional Entities have detailed knowledge regarding the transmission facilities within their regions. APPA would have the Regional Entities create a regional Reliability Standard to do so, subject to ERO review for reasonableness and consistency. Avista points out that WECC and the other Regional Entities have already reviewed and designated critical lower voltage transmission facilities, and the Reliability Standards currently apply to such facilities.

700. MISO asks for clarification with respect to the intent of adding transmission lines below 200 kV "that impact reliability" and whether the included lines are IROL-related facilities[263] or some other facilities. Progress and SERC suggest that it may be appropriate to limit the applicability of the Reliability Standard to all lines that are operated at 200 kV and above and to operationally significant circuits between 100 kV and 200 kV that are elements of IROLs.

701. California PUC believes that discretion about determining which lines are critical to the Bulk-Power System should be left to the individual state (working in concert with RTOs and ISOs), which has much greater knowledge of what is needed on the local level, rather than to NERC or the Regional Reliability Organization.

702. Progress, SERC, FirstEnergy and Avista argue that automatically subjecting lines below 200 kV to Reliability Standard FAC-003-1 would increase maintenance, documentation and reporting costs and impacts to land owners, but would not necessarily increase the reliability of the grid. LPPC does not object to eliminating the 200 kV bright line threshold, but believes that extending vegetation management practices to all facilities of 100 kV and above would unnecessarily extend the scope of the vegetation

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[263] An IROL-related facility is a facility whose outage would result in an Interconnection Reliability Operating Limit (IROL) violation.

management requirements, creating large cost increases for many utilities without creating a material increase in the reliability of the Bulk-Power System. FirstEnergy recommends that if the voltage level is lowered, implementation, especially for reporting requirements, should be spread over at least one year. Similarly, Xcel asks the Commission to allow flexibility in complying with this Reliability Standard for lower-voltage facilities that previously were not subject to this Reliability Standard.

703. EEI maintains that not changing this Reliability Standard would best maintain reliability, since removing the existing 200 kV threshold requirement could inadvertently expose the Bulk-Power System to a new set of risks. SoCal Edison argues that the Reliability Standard already covers transmission lines rated less than 200 kV, because Requirement 4.3 of FAC-003-1 states that this Reliability Standard "shall apply to all transmission lines operated at 200 kV and above and to any lower voltage lines designated by the regional reliability organization as critical to the reliability of the electric system in the region."

704. APPA opposes the Commission's proposal to direct NERC to change the applicability of this Reliability Standard. APPA argues that the Commission should deal with this concern by having NERC reevaluate the Reliability Standard. National Grid argues that expanding the applicability of Reliability Standards would not be appropriate because it could dramatically change the meaning of the Reliability Standards and would undermine the Reliability Standard development process which yielded the careful balances struck in developing the standards.

705. NERC argues that the Commission's proposed modification should be vetted through the Reliability Standards development process to better understand what will be gained in terms of impacts to the reliability of the Bulk-Power System. NERC notes that the current applicability of the Reliability Standard to 200 kV and above transmission lines was debated extensively by the industry, and any change to this requirement should be vetted again.

(b) Commission Determination

706. We will not direct NERC to submit a modification to the general limitation on applicability as proposed in the NOPR. However, we will require the ERO to address the proposed modification through its Reliability Standards development process. As explained in the NOPR, the Commission is concerned that the bright-line applicability threshold of 200 kV will exclude a significant number of transmission lines that could impact Bulk-Power System reliability. Although the regional reliability organizations are given discretion to designate lower voltage lines under the proposed Reliability Standard, none have designated any operationally significant lines even though there are lower voltage lines involving IROL as suggested by Progress and SERC. We continue to be

concerned that this approach will not prospectively result in the inclusion of all transmission lines that could impact Bulk-Power System reliability. In proposing to require the ERO to modify the Reliability Standard to apply to Bulk-Power System transmission lines that have an impact on reliability as determined by the ERO, we did not intend to make this Reliability Standard applicable to fewer facilities than it currently is with the 200 kV bright line applicability, but to extend the applicability to lower-voltage facilities that have an impact on reliability. We support the suggestions by Progress Energy, SERC and MISO to limit applicability to lower voltage lines associated with IROL and these suggestions should be part of the input to the Reliability Standards development process. Similarly, the ERO should evaluate the suggestions proposed by LPPC, APPA and Avista.

707. California PUC suggests that states should have discretion over what lines are critical to Bulk-Power System reliability. The Commission has been given the responsibility to approve Reliability Standards that assure the Reliable Operation of the Bulk-Power System, including which facilities are covered by the Reliability Standards. We cannot delegate that responsibility as proposed by California PUC. Further, since many transmission facilities traverse multiple states, we are concerned that this proposal could result in the Reliability Standard applying to a section of a line in one state but not applying to the same line in a neighboring state. Since a vegetation-related outage affects all customers connected to that transmission line, customers in both states could potentially have lower reliability as a result of one state having a less stringent standard than another.

708. Avista, LPPC, Progress and SERC raise concerns about the cost of implementing this Reliability Standard if the applicability is expanded to lower-voltage facilities. We recognize these concerns, and this was one of the reasons we proposed to apply this Reliability Standard to Bulk-Power System transmission lines that have an impact on reliability as determined by the ERO. We recognize that many commenters would like a more precise definition for the applicability of this Reliability Standard, and we direct the ERO to develop an acceptable definition that covers facilities that impact reliability but balances extending the applicability of this standard against unreasonably increasing the burden on transmission owners.

709. FirstEnergy and Xcel suggest that if the applicability of this Reliability Standard is expanded, the Commission should allow flexibility in complying with this Reliability Standard for lower-voltage facilities, or allow lower-voltage facilities one year before the Reliability Standard is implemented. The ERO should consider these comments when determining when it would request that the modification of this Reliability Standard to go into effect.

710. In response to EEI's concerns that removing the existing 200 kV threshold could expose the Bulk-Power System to a new set of risks, we clarify that we are not immediately modifying this Reliability Standard. Instead, it will go into effect as written and the ERO will revise it through the Reliability Standards development process, with the expectation that the applicability of this Reliability Standard will expand to include additional facilities that impact reliability that currently are not covered by this Reliability Standard. A modification that reduces the applicability of this Reliability Standard would not meet the Commission's directives. In response to SoCal Edison's argument that the Reliability Standard already addresses the Commission's concerns, the Commission agrees that while there appears to be a mechanism for inclusion of additional lines, none have been included. This lack of inclusion is in spite of the evidence that some lower voltage lines can have significant impacts on the Bulk-Power System, including IROLs and SOLs.

711. In response to APPA, NRECA and NERC we agree that the proposed modifications should be vetted through the Reliability Standards development process. The Commission's goal is to promote the Reliable Operation of the Bulk-Power System by including all of those entities necessary to comply with this Reliability Standard. We believe that requiring the Reliability Standard to include a greater number of entities and exclude those that will not affect reliability will more effectively sustain reliability than an overly exclusive list of applicable entities.

ii. Inspection Cycles

712. In the NOPR, the Commission proposed to direct NERC to submit a modification to FAC-003-1 that requires the ERO to develop a minimum vegetation inspection cycle that allows variation for physical differences.

(a) Comments

713. FirstEnergy states that a designation of a minimum annual inspection cycle is appropriate and the method of inspection (aerial or by ground) should be left to the transmission owner. Dominion cautions that if there is a requirement for annual inspections, it should be flexible and allow for different approaches to transmission line inspections.

714. APPA, Entergy, EEI, LPPC, Progress Energy, SERC and SoCal Edison disagree with the Commission's proposal to require the ERO to set minimum vegetation inspection cycles that allow for physical differences. APPA, Entergy and LPPC say that, instead of proposing the development of a Reliability Standard for minimum vegetation inspection cycles, the Commission should permit the transmission system owner or local

utility to determine the inspection cycle best suited for its system and adhere to that cycle, with compliance enforcement performed by the Regional Entities and the ERO.

715. Progress Energy and SERC believe that the Reliability Standard as written provides flexibility regarding vegetation inspection cycles and that the Commission should not impose requirements on the ERO to develop minimum inspection intervals on a continent with such regional diversity in climate and vegetation. In addition, Progress Energy argues that, where a particular region is heavily forested and has heavy rainfall along with extended or year round growing seasons, a "back stop" minimum inspection frequency could lead transmission owners to conduct inspections less frequently than what the local conditions require, which would lead to a lowest common denominator Reliability Standard. This could result in a transmission owner complying with the Reliability Standard while not adequately protecting the reliability of that region's transmission system.

716. Progress Energy and SERC argue that, since the performance metrics in FAC-003-1 require reporting of applicable transmission interruptions caused by vegetation, the compliance process associated with this Reliability Standard should appropriately identify transmission owners' inspection cycles that are not adequate, and the ERO can use its authority to remedy any vegetation-related outage that is attributed to the transmission owner's inspection frequency.

717. SoCal Edison states that transmission owners are already obligated by Requirement R1.1 to establish a minimum vegetation inspection schedule that allows adjustment for changing conditions. SoCal Edison believes that the best measure of an effective transmission vegetation management program is whether or not tree-to-line contacts are occurring. SoCal Edison recommends the Commission rescind the two proposed directives and order no further revisions to FAC-003-1 until such time as Reliability Standard is deemed unenforceable by the ERO or is not otherwise achieving its stated goals.

718. APPA and Progress Energy state that a minimum vegetation inspection cycle could result in an undue financial burden for some regions of the country, because they would be forced into a minimum cycle that might be inappropriate for their own region. For example, Progress Energy states that, where a particular region is arid, sparsely forested or has a minimum growing season, a "back stop" minimum could require a more frequent interval than is realistically needed. This would result in increased and unnecessary costs to the transmission owner and its customers without providing a comparable increase in reliability. EEI believes that a minimum inspection cycle will add nothing to the strength of the existing practices and could add a requirement that is not merited by actual circumstances in many locations.

(b) Commission Determination

719. The Commission is concerned about minimizing outages and supports a realistic inspection cycle. In the NOPR, the Commission proposed a minimum inspection cycle that takes account of physical differences as one way to address this concern. However, we recognize that there may be other options to achieve the same reliability goal. For example, the ERO could determine whether a prepared company-tailored inspection cycle is appropriate given the physical and geographic factors and, through audits, inspect individual vegetation management programs for compliance.

720. While the Commission disagrees that incorporating a backstop would lead to a lowest common denominator Reliability Standard, the Commission is dissuaded from requiring the ERO to create a backstop inspection cycle at this time. Instead, the Commission agrees that an entity's vegetation management program should be tailored to anticipated growth in the region and take into account other environmental factors. The goal is to assure that transmission owners conduct inspections at reasonable intervals. In the Commission's Vegetation Management Report, we found that many entities performed aerial or ground inspections less than every three years or even "as needed."[264]

721. The Commission continues to be concerned with leaving complete discretion to the transmission owners in determining inspection cycles, which limits the effectiveness of the Reliability Standard. Accordingly, the Commission directs the ERO to develop compliance audit procedures, using relevant industry experts, which would identify appropriate inspection cycles based on local factors. These inspection cycles are to be used in compliance auditing of FAC-003-1 by the ERO or Regional Entity to ensure such inspection cycles and vegetation management requirements are properly met by the responsible entities.

iii. Minimum Clearances on National Forest Service Lands

722. In the NOPR, the Commission did not propose to modify the ERO's general approach with respect to clearances. However, the Commission expressed its belief that any potential issues regarding minimum clearances on National Forest Service (Forest Service) lands should be dealt with on a case-by-case basis. The Commission requested comments on whether another approach would be more appropriate to address this issue.

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[264] Utility Vegetation Management snd Bulk Electric Reliability Report at 10-11, available at http://www.ferc.gov/industries/electric/indus-act/reliability/2004.asp (Vegetation Management Report).

(a) Comments

723. APPA believes that a case-by-case approach may have to be employed, since Forest Service lands are located all across the country and have different regional characteristics. APPA notes that U.S. Fish and Wildlife Service personnel have begun to take action regarding vegetation management on non-federal lands, and reports that APPA members have been told by U.S. Fish and Wildlife personnel to refrain from cutting vegetation at certain times of the year in the absence of an imminent reliability threat. APPA concludes that this information conflicts with specifying minimum nation-wide vegetation inspection/cutting cycles and clearances. In addition, APPA requests clarification of the Commission interpretation "we interpret the FAC-003-1 to require trimming that is sufficient to prevent outages due to vegetation management practices under all applicable conditions."

724. Several commenters express concern about the Commission's position that any potential issues regarding minimum clearances on National Forest Service lands should be dealt with on a case-by-case basis.[265] EEI, Progress Energy and SERC believe that this approach is inconsistent with the Reliability Standard's intent to use consistent approaches in setting minimum vegetation clearance distances on both private and public lands and the Commission's statement that this Reliability Standard requires minimum clearances that are "sufficient to prevent outages due to vegetation management practices under all applicable conditions."[266] Therefore, International Transmission, EEI, LPPC, Progress Energy and SERC assert that Reliability Standard FAC-003-1 should be applicable to all responsible entities including those with transmission on both private and public lands because consistency is the only way to provide a uniform and reliable electrical system. Dominion suggests the Commission defer to NERC and the stakeholder process to develop specifications for clearances.

725. Progress Energy and SERC note that EEI and certain federal agencies[267] have jointly addressed the issue of consistency in vegetation management work on federal

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[265] See, e.g., EEI, Energy, International Transmission, Progress Energy, SERC, LPPC and MISO.

[266] The NOPR states that "Accordingly, we interpret the FAC-003-1 to require trimming that is sufficient to prevent outages due to vegetation management practices under all applicable conditions…" NOPR at P 380.

[267] Forest Service, Bureau of Land Management, Fish & Wildlife Service, National Park Service, and U.S. Environmental Protection Agency.

lands, and developed a memorandum of understanding (Vegetation MOU) which sets the framework for managing vegetation on transmission line rights-of-way under federal agency jurisdiction.[268] Progress Energy and SERC recommend using the EEI's Vegetation MOU framework for managing vegetation on transmission line rights-of-way under federal agency jurisdiction rather than the case-by-case approach proposed in the NOPR. LPPC recommends creating a bright-line when it comes to utilities' obligations (and rights) for trimming vegetation located on Forest Service lands. Avista and Portland General ask that the Vegetation MOU be affirmed by the Commission and permitted to govern transmission line rights-of-ways located on lands managed by federal land management agencies.

726. SoCal Edison believes that transmission owners should be allowed the latitude to establish measures/procedures for less rigid tree-to-line clearances in response to state and federal agency demands or requests but is concerned that these measures/procedures will prove to be of little or no value in the event of an ERO investigation into a tree-to-line contact occurring within national/state forestry boundaries or on private property.

727. California PUC points out that California already has requirements applicable to minimum vegetation clearance, and that the Commission must take care to assure that any mandatory Reliability Standard does not preempt the ability of California (and other states with similar state standards) to impose stricter requirements that have no adverse impacts on reliability.

728. FirstEnergy states that the standard should define rights-of-way to encompass the required clearance area instead of the corresponding legal land rights. Some rights-of-way may be larger to accommodate future needs and therefore may exceed clearances needed for existing lines. FirstEnergy believes that Reliability Standards should not require clearing entire rights-of-way when the required clearance for existing lines does not take up the entire right-of-way.

(b) Commission Determination

729. As proposed in the NOPR, the Commission approves Reliability Standard FAC-003-1 with no proposed modification on the issue of clearances. The Commission reaffirms its interpretation that FAC-003-1 requires sufficient clearances to prevent outages due to vegetation management practices under all applicable conditions. As to

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[268] The Vegetation MOU is available at http://www.eei.org/industry_issues/environment/land/vegetation_management/EEI_MOU_FINAL_5-25-06.pdf

APPA's requests for clarification concerning the term "under all applicable conditions," the Reliability Standard already addresses this issue in Requirement R3.2 by allowing for exceptions for natural disasters (including wind shears and major storms) that cause vegetation to fall into the transmission lines from outside the ROW. The Commission therefore finds that no clarification is required in response to APPA.

730. The Commission agrees that ownership of the land does not change the impact of a vegetation-related outage on the Bulk-Power System. However, the present Reliability Standard leaves the determination and documentation of "clearance 1" to transmission owners. As such, there are no specific clearances, or criteria/procedures to develop clearances, before the Commission for approval. What is in front of the Commission relative to "locations on the right-of-way where the Transmission Owner is restricted from attaining the clearances specified in Requirement R1.2.1" is addressed in Requirement R1.4. Requirement R1.4 states that "Each Transmission Owner shall develop mitigation measures to achieve sufficient clearances for the protection of the transmission facilities when it identifies locations on the right-of-way where the Transmission Owner is restricted from attaining the clearances specified in Requirement R1.2.1." This Requirement addresses the instances when an entity cannot attain the clearances that it needs on land that it controls. Since there are multiple mitigation measures that the entity can employ to achieve the goal of preventing outages due to vegetation management practices, the Commission has stated that any potential issues regarding minimum clearances on Forest Service lands should be dealt with on a case-by-case basis.

731. Avista and Portland General ask the Commission to endorse the Vegetation MOU. The Commission reiterates its direction that the minimum clearances must be sufficient to avoid any sustained vegetation-related outages for all applicable conditions. The Vegetation MOU references IEEE 516 as the only way to determine applicable minimum clearances. The Commission declines to endorse the use of IEEE 516 as the only minimum clearance because it is intended for use as a guide by highly-trained maintenance personnel to carry out live-line work using specialized tools under controlled environments and operating conditions, not for those conditions necessary to safely carry out vegetation management practices.[269] Further, the allowable clearances in the IEEE standard are significantly lower than those specified by the relevant U.S. safety codes. As such, use of IEEE clearance provision as a basis for minimum clearance prior to the next tree trimming as a Requirement in vegetation management is not appropriate for safety and reliability reasons. For example, the IEEE Standard 516-2003 specifies a

[269] Controlled environments and operating conditions include clear days without precipitation, high winds or lightning.

2.45-foot clearance from a live conductor for the 120 kV voltage class,[270] whereas the ANSI Z-133 standard specifies 12 feet, 4 inches as the approach distance for the 115 kV voltage class.[271]

732. Accordingly, the Commission directs the ERO to develop a Reliability Standard that defines the minimum clearance needed to avoid sustained vegetation-related outages that would apply to transmission lines crossing both federal land and non-federal land. While this consensus is developed, the Commission directs the ERO to address any potential issues regarding mitigation measures needed to assure these minimum clearances on Forest Service lands are appropriate on a case-by-case basis. The Commission also directs the ERO to collect outage data for transmission outages of lines that cross both federal and non-federal lands, analyze it, and use the results of this analysis and information to develop a Reliability Standard that would apply to transmission lines crossing both federal and non-federal land.

733. In regard to California PUC's concern about its ability to impose stricter requirements on vegetation clearances, the Commission notes that section 215(i)(3) of the FPA states that nothing in section 215 shall be construed to preempt the authority of a state to take action to ensure the reliability of electric service within that state, as long as the action is not inconsistent with any Reliability Standard. Therefore, the State of California may set its own vegetation management requirements that are stricter than those set by the Commission as long as they do not conflict with those set by the Commission. Further, the Commission notes that once a Reliability Standard is established, California PUC can develop stricter rules to be applied within the state of California, and if it wants them to be enforceable under section 215 of the FPA, could submit those Reliability Standards to the ERO and the Commission for approval as a regional difference.

734. FirstEnergy suggests that rights-of-way be defined to encompass the required clearance areas instead of the corresponding legal rights, and that the standards should not require clearing the entire right-of-way when the required clearance for an existing line does not take up the entire right-of-way. The Commission believes this suggestion is

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[270] Institute of Electrical and Electronics Engineers, Inc. (IEEE) Standard 516-2003, IEEE Guide for Maintenance Methods at 20.

[271] ANSI Z133, American National Standards Institute Standard for Tree Care Operations – Pruning, Trimming, Repairing, Maintaining and Removing Trees, and Cutting Brush – Safety Requirements.

reasonable and should be addressed by the ERO. Accordingly, the Commission directs the ERO to address this suggestion in the Reliability Standards development process.

iv. Summary of Commission Determinations

735. The Commission approves FAC-003-1 as mandatory as enforceable. In addition, while we do not direct the ERO to submit a modification to the general limitation on applicability as proposed in the NOPR, we require the ERO to address the proposed modification through its Reliability Standards development process as discussed above. Further, while the Commission is dissuaded from requiring the ERO to create a backstop inspection cycle at this time, it directs the ERO to develop compliance audit procedures to identify appropriate inspection cycles based on local factors. These inspection cycles are to be used in compliance auditing of FAC-003-1 by the ERO or Regional Entity to ensure such inspection cycles and vegetation management requirements are properly met by the responsible entities. Finally, the Commission directs the ERO to develop a Reliability Standard through the Reliability Standard development process that defines the minimum clearance needed to avoid sustained vegetation-related outages that would apply to transmission lines crossing both federal land and non-federal land. While this consensus is developed, the Commission directs the ERO to address any potential issues regarding mitigation measures needed to assure these minimum clearances on Forest Service lands are appropriate on a case-by-case basis. The Commission also directs the ERO to collect outage data for transmission outages of lines that cross both federal and non-federal lands, analyze it, and use the results of this analysis and information to develop a Reliability Standard that would apply to transmission lines crossing both federal and non-federal land.

d. Facility Ratings Methodology (FAC-008-1)

736. FAC-008-1 requires each transmission owner and generation owner to develop a facility rating methodology for its facilities, which should consider manufacturing data, design criteria (such as IEEE, ANSI or other industry methods), ambient conditions, operating limitations and other assumptions. This methodology is to be made available to reliability coordinators, transmission operators, transmission planners and planning authorities who have responsibility in the same areas where the facilities are located for inspection and technical reviews.

737. In the NOPR, the Commission proposed to approve Reliability Standard FAC-008-1 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission proposed to direct NERC to develop a modification to FAC-008-1 through the Reliability Standards development process that requires transmission and generation facility owners to: (1) document underlying assumptions and methods used to determine normal and emergency facility

ratings; (2) develop facility ratings consistent with industry standards developed through an open process such as IEEE or CIGRE and (3) identify the limiting component(s) and define the increase in rating based on the next limiting component(s) for all critical facilities.

i. Methodology Used To Determine Facility Ratings and Documentation of Underlying Assumptions

(a) Comments

738. EEI, Valley Group, MidAmerican and TANC support the Commission's proposal to require additional documentation as a reasonable means to provide more transparency and consistency. EEI suggests that this requirement could be accommodated with a provision for the disclosure of such information upon request by a registered user, owner or operator. TANC supports the Commission's proposal to not require a uniform facility rating methodology and recommends that the Commission adopt a policy that provides for each transmission owner and generation owner to develop and document a facility rating methodology, which is consistent with industry methodologies, for their facilities. TANC also states that the methodology used for developing facility ratings should include a description of and justification for all of the assumptions. Valley Group states that it is extremely important that the underlying assumptions and methods are documented and known to all parties. Valley Group maintains that this will also ensure that the rating assumptions used by operating and planning functions are consistent with each other. Valley Group emphasizes that making these assumptions open is important, especially regarding paths between different transmission owners, to ensure that transmission owners cannot exercise market power. It argues that open assumptions will also provide rational grounds for dispute resolution.

(b) Commission Determination

739. As EEI, TANC, Valley Group and MidAmerican discuss in their comments, the Commission's proposal to modify FAC-008-1 to require additional documentation supports the Commission's goals of improving uniformity and transparency in the facility ratings process. EEI's suggestion that having this information available for review upon request of a registered user, owner or operator should be considered by the ERO in its Reliability Standards development process. As proposed in the NOPR, the Commission directs the ERO to submit a modification to FAC-008-1 that requires transmission and generation facility owners to document underlying assumptions and methods used to determine normal and emergency facility ratings. As stated in the NOPR, the Commission believes that this added transparency will allow customers, regulators and other affected users, owners and operators of the Bulk-Power System to understand how

facility owners set facility ratings through differing methods that provide equivalent results.

ii. Rating Facilities Consistent with Industry Standards Developed Through an Open Process such as IEEE and CIGRE

(a) Comments

740. The Valley Group states that the Commission correctly identifies IEEE and CIGRE as examples of open process methodologies suitable for overhead transmission line ratings calculations. It claims that IEEE and CIGRE are the only methodologies which make their algorithms available to everybody, and clearly document their assumptions. Valley Group notes that both of these methodologies will undergo a revision for accuracy regarding calculations for high temperatures and high current densities in the next two years, which may lead in some cases to slightly lower line ratings, although the changes are not expected to be substantial.

741. APPA suggests that the proposal to rate facilities consistent with industry methodologies developed through an open process such as IEEE and CIGRE should be considered in the ERO's Reliability Standards development process rather than ordered by the Commission. LPPC asks the Commission to require only that facility ratings be consistent with good utility practice. According to LPPC, to the extent facility rating methodologies need to be more prescriptive than good utility practice, the details must be spelled out in the ERO Reliability Standards themselves, not by reference to other unspecified industry methodologies. LPPC believes that it would be poor policy for the Commission to endorse these methodologies since it would be impossible to police the processes by which such organizations develop their methodologies. MidAmerican states that the Commission should recognize that the proposal to require facility ratings be consistent with industry methodologies developed through an open process is potentially problematic, noting that certain aspects of the development of facility ratings are based on industry standards that are not developed through an open process, such as information provided by engineering textbooks or manufacturer information that is not specifically referenced in any current standard. MidAmerican recommends that the Commission delete the requirement that facility ratings be "developed through an open process such as IEEE or CIGRE" or add other sources that the Commission would find appropriate, such as the results of accepted scientific and engineering investigations and common sense. MRO requests that the Commission clarify whether its directive to modify FAC-008-1 to develop facility ratings consistent with industry standards developed through an open process such as IEEE or CIGRE would allow for legitimate regional differences such as climate, terrain or population density.

(b) **Commission Determination**

742. In the NOPR, the Commission stated, "While not proposing to mandate a particular methodology, we do propose that the methodology chosen by a facility owner be consistent with industry standards developed through an open process such as IEEE or CIGRE."[272] These processes have been validated through actual testing and have been shown to provide appropriate results. Information from engineering textbooks, common sense or manufacturer information would be part of the underlying assumptions. The Commission's intent in the NOPR was to require that FAC-008-1 be modified to require that facility ratings be developed consistent with industry standards developed through an open, transparent and validated process. The Commission agrees with Valley Group that IEEE and CIGRE are two examples of such processes and disagrees with LPPC that reference to industry standards is poor policy. Industry standards that have been verified by actual testing are appropriate. However, the Commission agrees with MidAmerican that IEEE and CIGRE are just two examples of such bodies; any other open process that has been technically validated for its provision of accurate, consistent ratings is also acceptable. The ERO should consider the concerns raised by LPPC and MRO in its Reliability Standards development process, and is hereby directed to do so. The Commission does not expect there to be any regional differences because the only differences should be from different underlying assumptions that are not defined by the Reliability Standard.

iii. **Identify the Limiting Component(s) and Define for all Critical Facilities the Rating Based on the Next Limiting Component within the Same Facility**

(a) **Comments**

743. TANC maintains that the rating information provided by the transmission owners and generator owners should include additional information about all of the limiting components of the elements (e.g., transmission lines, transformers, etc.) for all critical facilities. Access to such information will enable neighboring systems to accurately study the effects of other facilities on their own systems and determine the critical elements for increasing facility ratings.

744. Valley Group states that identifying the limiting elements is an excellent objective for reliability enhancement, but notes that its granularity must be limited to major elements of the circuits, such as transformers and breakers, while treating the

[272] NOPR at P 404.

transmission lines as single elements. Valley Group also notes that, of the two examples discussed in the NOPR, the example regarding relay settings is technically well justified, whereas rating the line based on a single limiting span is generally impractical because line design engineers add to the National Electric Safety Code minimum requirements "safety buffers," which vary depending on their confidence in the accuracy of design calculations.

745. APPA is concerned about the possible "unintended consequences" of this modification and questions whether this proposed Requirement can be done as a practical matter; how many critical facilities and limiting components would have to be modeled to meet such a Requirement; and whether the cost of such modeling is justified by the reliability benefits. Dynegy, MISO and Wisconsin Electric also oppose this requirement because it is ambiguous, the additional work required to identify the increase in rating based on the next limiting component(s) is unwarranted and potentially costly, and the need for any such specific information is questionable. Dynegy and Wisconsin Electric do not believe there is a widespread need for this type of information and recommend that the need for it be explored on a case-by-case basis rather than including a global requirement in the standards.

746. Dynegy, FirstEnergy and MISO state that it is not clear what specific criteria would be used to define "critical facilities" and "limits." EEI also states that developing a practical definition of "critical facilities" presents a challenge, and that compliance would require the analysis of possibly hundreds of thousands of "limiting" transmission elements to determine whether a limit is of primary concern or is contingent on the status of other nearby elements or system conditions at a particular time. EEI suggests that, rather than requesting that the industry develop a definition, it may be more useful for the Commission to recommend that the industry develop a set of high-level criteria that could be used to identify those transmission elements that create significant potential limits that are independent of other factors and considerations.

747. EEI and TVA assert this recommendation does not seem to be intended to enhance reliability but to provide additional commercial information to the market, and may not be appropriate to include in a Reliability Standard. Portland General further points out that this information can be obtained from a transmission provider by submitting a transmission or interconnection request when ATC is not posted or not available. TVA comments that, since the focus of this proceeding is the Reliable Operation of the Bulk-Power System, changes to a proposed Reliability Standard, such as FAC-008-1, that appear designed to promote maximum commercial use of the grid are unwarranted in this proceeding and could jeopardize, rather than further, reliable transmission system operations.

748. MRO seeks clarification about whether the proposed modification will require that all limiting facilities elements be published. MRO believes that serious confidentiality issues are raised due to the security-sensitive nature of the information and urges the Commission not to require the publication of such information.

749. Dominion states that the Commission should exclude from this requirement facilities that are covered under an open, regional transmission expansion planning process, such as the Regional Transmission Expansion Plan process in PJM, where any interested party can be involved in the studies and determine what the limitations are and what could be done to increase transmission capacity.

750. International Transmission states that, if the Commission were to require defining the increase in facility rating based on the next limiting element, it should restrict such application to transmission elements where the conductor itself is not the limiting element. International Transmission explains that in cases where the line must be completely rebuilt, it would not be feasible to estimate the increase in facility rating, since the new line could be specified to carry virtually any amount of power.

751. MISO questions how a generator operator or generation owner would identify the increase in rating based on the next most limiting component(s) associated with generator output. FirstEnergy believes that this modification should recognize that generators may need to rely on transmission owners to point out facilities that are more limiting than the generator facilities.

752. Manitoba's technical experts disagree with the Preliminary Staff Assessment regarding FAC-008-1. The Reliability Standard properly places the responsibility of determining facility ratings with the facility owners. Manitoba also states that, since this Reliability Standard requires that the "Facility Rating shall be equal to the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility," information on the next limiting component is already identified. Contrary to the Commission's view, Manitoba does not believe it would be appropriate in this Reliability Standard to identify the increase in rating for all critical facilities based on the next limiting component. In a networked system, there may be other limitations that set the current carrying capability of the critical facility.

753. Manitoba further notes that the Commission proposal may lead to international conflicts in Reliability Standards. Manitoba states that a mandated change to FAC-008-1, which forces an entity to accept facility ratings beyond its risk tolerance, would be grounds for Manitoba to recommend that the provincial government of Manitoba not approve this Reliability Standard because it would degrade reliability.

754. APPA suggests that the proposal to identify the limiting component and define for all critical facilities the rating based on the next limiting component be considered in the ERO's Reliability Standards development process rather than ordered by the Commission.

(b) Commission Determination

755. The Commission agrees with TANC that this modification would provide useful information to neighboring systems and users, owners and operators of the Bulk-Power System. The Commission also agrees with Valley Group that identifying the limiting elements of facilities enhances reliability by providing operators specific information about the limiting elements and therefore allowing them to assess the risks associated with circuit loadings.

756. In response to the comments of APPA, Dynegy, EEI, MISO and Wisconsin Electric, the Commission clarifies that this Reliability Standard and the Commission's proposed modification apply to facilities. As defined in the NERC glossary, a facility is "a set of electrical equipment that operates as a single Bulk Electric System Element[273] (e.g., a line, a generator, a shunt compensator, transformer, etc.)." The most limiting component in a facility determines its rating, just like the rating of a chain is determined by the weakest link. The Commission's proposed modification would require identifying and documenting the limiting component for all facilities and the increase in rating if that component were no longer the most limiting component; in other words, the rating based on the second-most limiting component. The Commission further clarifies that this Reliability Standard will require this additional thermal rating information only for those facilities for which thermal ratings cause the following: (1) an IROL; (2) a limitation of TTC; (3) an impediment to generation deliverability or (4) an impediment to service to major cities or load pockets.

757. EEI and TVA raise concerns that this modification promotes commercial use of the grid rather than ensuring Reliable Operation of the Bulk-Power System, and relates more to transmission access than reliable operations. The Commission disagrees that this modification relates primarily to transmission access. When the transmission operators know which component within the transmission element is limiting they have more information to inform their decisions about how to provide for the Reliable Operation of the Bulk-Power System. Our proposed modification does not require any entity to invest in equipment to increase ratings of any facility; it simply requires the next limiting componet of each facility to be identified in order to understand what components are

[273] An element is made up of one or more components.

causing the limits that are to be used in reliability mitigation assessments. The identification of the first limiting component is already an inherent requirement in the existing rating process. As clarified above, the modification to identify an increase in rating of the transmission element that would result from removing the first limitating component applies only to critical facilities whose thermal ratings have been reached causing an SOL or IROL condition. As Dominion highlights in its comments, this information is already identified in the planning processes of some RTOs and ISOs.

758. In response to the concerns raised by EEI and MRO about sharing confidential, market-sensitive information, the Commission disagrees that ratings information is confidential or market-sensitive. All users, owners and operators should have access to the facility ratings in order to operate the system reliably. Section 215(a)(4) of the FPA defines Reliable Operation, in part, as operating the elements of the Bulk-Power System within equipment and electric system thermal stability limits.[274] Without knowing the ratings, it is not possible to know whether this requirement is being met. As to the argument that this information is confidential, the Commission clarifies that, as with the other information required by this Reliability Standard, the additional information required by this modification would be shared only with users, owners and operators of the Bulk-Power System.

759. In response to Dominion's comments, if the PJM Regional Transmission Expansion Planning process meets the criteria, there is no need to exclude facilities covered by that process from this requirement.

760. The Commission directs the ERO to consider International Transmission's comments regarding requiring information about the increase in facility rating based on the next limiting element only for lines where the conductor itself is not the limiting element in its Reliability Standards development process. Similarly, the ERO should also consider the comments from MISO and FirstEnergy that generators will have difficulty determining the increase in ratings due to the next limiting element, since in most cases the generator itself would be the most limiting element.

761. We agree with Manitoba that this Reliability Standard properly places the responsibility to determine facility ratings on the facility owner. The Commission is not proposing to change this. We also agree with Manitoba that the most limiting component is already identified when facility ratings are determined. The Commission is only directing transmission and generation owners to provide additional information on the next limiting component within the facility so that facility ratings are more transparent.

[274] 16 U.S.C. 824o(a)(4).

762. In response to Manitoba's and APPA's concerns, we recognize that this is an additional requirement with some complexities, and this modification will go through the ERO Reliability Standards development process. We do not intend to usurp the Reliability Standards development process, where Manitoba may raise its concerns for the ERO to consider.

iv. Applicability to Generator Owners

(a) Comments

763. Xcel states that this Reliability Standard should not apply to generator owners because capability testing, rather than using mathematical calculations, is the preferred method of determining generating unit capability. Capability testing clearly includes the capability of all the supporting components behind the generator that are required to produce a MW of capability. Xcel also states that this proposed Reliability Standard, if applied to generating units, would not improve system reliability and could result in conflicting and confusing unit capability ratings. Xcel notes that generating units already are required to be capability-tested on a periodic and seasonal basis to demonstrate unit gross and net capability in accordance with proposed standards MOD-024-1 and MOD-025-1.

764. FirstEnergy also points out that facility ratings for nuclear units are part of NRC license agreements and that the ratings methodologies included in NRC license agreements are approved by NRC. FirstEnergy proposes that compliance with NRC ratings methodology requirements should be assumed to comply with this Reliability Standard.

(b) Commission Determination

765. The Commission agrees with Xcel that an actual test could be used as a substitute for a mathematical calculation of capability, and we ask the ERO to consider these comments in its Reliability Standards development process. The Commission understands that NRC provides ratings methodologies for nuclear power plants and not for the transmission system. Capacity ratings of nuclear generators determined using this methodology are acceptable for reliability purposes. We also direct the ERO to consider FirstEnergy's comments in its Reliability Standards development process.

v. Compliance with Blackout Report Recommendation No. 27

(a) Comments

766. Manitoba believes this Reliability Standard meets the requirement of Blackout Report Recommendation No. 27 because the recommendation does not require a uniform set of methodologies for rating facilities, but instead only recommends that there be a clear, unambiguous requirement to rate transmission lines.

767. Valley Group notes that, while the Commission's proposal would direct the ERO to respond to a part of Blackout Report Recommendation No. 27, it does not address the important second part of the Recommendation, namely dynamic ratings. Valley Group notes that dynamic ratings offer a very powerful tool both for maximizing the capabilities of transmission paths and for avoiding unnecessary transmission line loading relief. Valley Group also notes that dynamic ratings, based either on ambient-adjusted ratings or ratings generated by real-time monitoring systems, are widely used in the PJM system, while broader real-time ratings are applied on certain lines in SPP and ERCOT and at several individual utilities. Valley Group states that controlling unnecessary operator interventions with dynamic ratings both increases the reliability of Bulk-Power System and improves its economy. Valley Group concludes that it would be highly desirable for the ERO to establish policies and procedures regarding dynamic ratings – as recommended by the Blackout Report, and recommends that the Commission include such guidance in its Final Rule.

(b) Commission Determination

768. The Commission believes that implementation of the modifications discussed earlier to Reliability Standard FAC-008-1 meets our goal of implementing Blackout Report Recommendation No. 27, which is to "develop enforceable standards for transmission line ratings."[275] To achieve a clear and unambiguous Requirement to rate transmission lines, it is important to understand the underlying assumptions and the methodologies that will be used to develop those ratings. The Commission recognizes that dynamic line ratings are an innovative application, and directs the ERO to consider the comments from Valley Group in future revisions of this Reliability Standard.

[275] Blackout Report at 162.

vi. General Comments

769. APPA notes that FAC-008-1 should be revised to replace Levels of Non-Compliance with Violation Security Levels, and to include Violation Risk Factors on all FAC-008-1 requirements.

(a) Commission Determination

770. The Commission acknowledges that the Reliability Standards are changing. In this Final Rule, we are ruling on the Reliability Standards as they were filed, and these documents use the term Levels of Non-Compliance. The ERO should address APPA's comments in its Reliability Standards development process.

vii. Summary of Commission Determination

771. Accordingly, as discussed in the responses to comments above, the Commission approves FAC-008-1 as mandatory and enforceable. In addition, we direct the ERO to develop modifications to FAC-008-1 through its Reliability Standards development process requiring transmission and generation facility owners to: (1) document underlying assumptions and methods used to determine normal and emergency facility ratings; (2) develop facility ratings consistent with industry standards developed through an open, transparent and validated process and (3) for each facility, identify the limiting component and, for critical facilities, the resulting increase in rating if that component is no longer limiting.

e. Establish and Communicate Facility Ratings (FAC-009-1)

772. FAC-009-1 requires each transmission owner and generation owner to establish facility ratings consistent with its associated facility ratings methodology and provide those ratings to its reliability coordinator, transmission operator, transmission planner and planning authority. In the NOPR, the Commission proposed to approve FAC-009-1 as mandatory and enforceable.

i. Comments

773. APPA supports approval of FAC-009-1 as a mandatory and enforceable Reliability Standard.

ii. Commission Determination

774. FAC-009-1 serves an important reliability purpose of ensuring that facility ratings are determined based on an established methodology. Further, the proposed Requirements set forth in FAC-009-1 are sufficiently clear and objective to provide

guidance for compliance. Accordingly, the Commission approves Reliability Standard FAC-009-1 as mandatory and enforceable.

f. Transfer Capability Methodology (FAC-012-1)

775. Proposed Reliability Standard FAC-012-1 requires each reliability coordinator and planning authority to document the methodology used to develop its inter-regional and intra-regional transfer capabilities. This methodology must describe how it addresses transmission topology, system demand, generation dispatch and use of projected and existing commitment of transmission.

776. In the NOPR, the Commission explained that, because the methodology to calculate transfer capability used by a reliability coordinator or planning authority has not been submitted to the Commission, it is not possible to determine at this time whether FAC-012-1 satisfies the statutory requirement that a proposed Reliability Standard be just, reasonable, not unduly discriminatory or preferential, and in the public interest. Thus, the NOPR did not propose to approve or remand this Reliability Standard until the regional procedures are submitted.

777. The NOPR explained that FAC-012-1 only requires that the regional reliability organization provide documentation on transfer capability methodology and provide it to entities such as the relevant transmission planner, planning authority, reliability coordinator and transmission operator. The Reliability Standard does not contain clear requirements on how transfer capability should be calculated, which has resulted in diverse interpretations of transfer capability and the development of various calculation methodologies. The NOPR suggested that FAC-012-1 should, as a minimum, provide a framework for the transfer capability calculation methodology including data inputs and modeling assumptions. In addition, the NOPR asked for comments on the most efficient way to make the above information transparent for all participants.

i. Methodology

(a) Comments

778. APPA, International Transmission and MidAmerican agree that the proposed FAC-012-1 is not sufficient and should not be accepted for approval as a mandatory Reliability Standard. They suggest that, at a minimum, this Reliability Standard should provide a framework for the transfer capability calculation methodology, including data inputs and modeling assumptions. APPA notes that, in the Western Interconnection and ERCOT, the sets of rules for long-range and operational planning studies are transparent to all users, owners and operators and suggests that in the Eastern Interconnection, where multiple regions exist, the Regional Entities should consider developing an umbrella

organization or process comprised of representatives from each of the Eastern Interconnection's Regional Entities to establish the planning and operational rules for the Interconnection. APPA suggests that this approach would work well to identify critical facilities, by using consistent and transparent study assumptions, and it would also minimize seams issues when establishing facility rating and transfer capabilities throughout the entire Interconnection. International Transmission states that this Reliability Standard should identify the performance that is required, that specifics of how transfer capability should be calculated do not belong in this Reliability Standard, and that a reference document could be developed for this purpose.

(b) Commission Determination

779. Although we are not proposing to approve or remand this Reliability Standard, because it is applicable to the regional reliability organization, the Commission agrees with APPA, International Transmission and MidAmerican that, at a minimum, this Reliability Standard should provide a framework for the transfer capability calculation methodology, including data inputs and modeling assumptions. The Commission agrees with APPA that there should be an umbrella organization to assure consistency within the Eastern Interconnection and the other interconnections. We believe that the best organization to do this would be the ERO, because it is the only organization with knowledge of all of the individual Regional Entities that can carry out this function. Therefore, we direct the ERO to modify this Reliability Standard to provide such a framework.

ii. Transparency and Confidentiality

(a) Comments

780. International Transmission cautions that, in making information regarding the framework for calculating transfer capability transparent to all participants, a balance must be maintained between the need for transparency and the need to maintain the confidentiality of sensitive critical energy infrastructure information (CEII). The results of certain critical contingency analyses would not be appropriate for public disclosure, but may be the basis for transfer capability limits imposed on some interfaces.

781. MidAmerican suggests that transparency could be provided in the Eastern Interconnection by each reliability coordinator and each planning authority posting the transfer capability calculations performed pursuant to FAC-012-1, along with a document outlining how they were determined and the purposes for which they are used on a protected website. The protected site should be accessible only to qualified entities. MidAmerican suggests that the Western Interconnection's approach, the WECC message system used for certain qualified paths, is an appropriately transparent system.

(b) Commission Determination

782. Although we are not proposing to approve or remand this proposed Reliability Standard, the Commission believes that it can be improved. The Commission believes that the process used to determine transfer capabilities should be transparent to the stakeholders, and agrees with International Transmission and MidAmerican that the results of those calculations should not be available for public disclosure but only for qualified entities on a confidential basis. In addition, the process and criteria used to determine transfer capabilities must be consistent with the process and criteria used for other users of the Bulk-Power System. Simply stated, the criteria used to calculate transfer capabilities for use in determining ATC must be identical to those used in planning and operating the system. The Commission directs the ERO to take this into account in its Reliability Standards development process, and to modify the Reliability Standard consistent with Order No. 890 in Docket No. RM05-25-000.

783. Accordingly, the Commission affirms the NOPR proposal to not approve or remand this Reliability Standard. We understand that the ERO implemented its Reliability Standards development process to revise the Reliability Standard and will be submitting it in accordance with the schedule identified in Order No. 890.

g. Establish and Communicate Transfer Capability (FAC-013-1)

784. FAC-013-1 requires either the reliability coordinator or the planning authority, as determined by the regional reliability organization, to calculate transfer capabilities consistent with its transfer capability methodology and provide those capabilities to its transmission operators, transmission service providers and planning authorities.

785. In the NOPR, the Commission proposed to approve Reliability Standard FAC-013-1 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission proposed to direct NERC to develop a modification to FAC-013-1 that: (1) makes it applicable to all reliability coordinators and (2) removes the regional reliability organization as the entity that determines whether a planning authority has a role in determining transfer capabilities.

i. Comments

786. APPA supports the Commission's proposal to approve FAC-013-1 as a mandatory and enforceable Reliability Standard, but disagrees with the Commission's proposed modification to remove the regional reliability organization as the entity that determines whether a planning authority has a role in determining transfer capabilities. APPA believes that regional committee processes are essential to determine, through their

planning and operating committees, which planning authorities and reliability coordinators are responsible for determining and distributing each of the specific transfer capability values within each regional footprint. APPA proposes that in the Eastern Interconnection, where multiple regional reliability organizations and Regional Entities exist, the Regional Entities should consider developing an umbrella organization or process comprised of representatives from each of the Eastern Interconnection's Regional Entities, to establish the planning and operational planning rules for the Interconnection. APPA believes that such a program would minimize seams issues when establishing facility ratings and transfer capabilities throughout the entire Interconnection.

787. MidAmerican supports the Commission's proposal to make this Reliability Standard applicable to all reliability coordinators and planning authorities. MidAmerican believes in a clear separation of responsibilities between the reliability coordinators and planning authorities. MidAmerican believes that reliability coordinators should calculate transfer capabilities in the operating horizon, while planning authorities calculate transfer capabilities in the planning horizon, and would support additional clarification of the standard by explicitly stating the continued responsibility of planning authorities to calculate transfer capabilities for the planning horizon.

788. TANC is concerned that, if the transmission service provider and the transmission operators are specifically named in Requirement R2.1 of this Reliability Standard, but are not included in the Applicability section, this will cause ambiguity. TANC questions whether a transmission service provider or transmission operator that does not receive the transfer capabilities from the reliability coordinator will be held accountable and penalized for not producing the transfer capabilities when the reliability coordinator never provided them. If this is the case, TANC questions whether there will be different penalties for the transmission service provider and transmission operator, or whether they will be subject to the same penalties as the entities listed in the Applicability section.

789. EEI believes that the full range of issues discussed here are currently under review under Docket No. RM05-25 and proposes that these issues remain in a single forum to avoid confusion.

ii. **Commission Determination**

790. The Commission does not believe that the regional reliability organization should be able to decide the type of entity to which this Reliability Standard applies. The Commission disagrees with APPA that regional committee processes are essential to determine which planning authorities and reliability coordinators are responsible for determining and distributing each of the specific transfer capability values. Reliability coordinators have a wider-area view of the transmission system than planning authorities, which is important in calculating inter- and intra-regional transfer capabilities.

Therefore, the Commission agrees with MidAmerican that reliability coordinators should calculate transfer capabilities in the operating horizon. The Commission will not address MidAmerican's proposal regarding calculating transfer capabilities in the planning horizon because those Reliability Standards are being considered in Docket No. RM07-3-000 and are therefore beyond the scope of this proceeding.

791. The Commission, as discussed elsewhere in this Final Rule, has considered APPA's proposal concerning creating an umbrella organization in regard to FAC-012-001.[276]

792. In regard to TANC's concern that transmission service providers and transmission operators may be liable because they are specifically named in Requirement R2.1, the Commission clarifies that, because the Reliability Standard only provides that the transmission service providers and transmission operators receive information regarding transfer capabilities, and does not require an affirmative action on the part of transmission service providers or transmission operators, a transmission service provider or transmission operator cannot be liable for violating the Reliability Standard.

793. The Commission disagrees with EEI that these matters should be evaluated only in the OATT Reform Proceeding. In Order No. 890, the Commission directed transmission owners to use the ERO's Reliability Standards development process to implement changes required in that Final Rule.[277]

794. Accordingly, the Commission approves Reliability Standard FAC-013-1 as mandatory and enforceable, and, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to FAC-013-1 through the Reliability Standards development process that makes it applicable to reliability coordinators.

6. INT: Interchange Scheduling and Coordination

795. The Interchange Scheduling and Coordination (INT) group of Reliability Standards addresses interchange transactions,[278] which occur when electricity is transmitted from a seller to a buyer across the power grid. Specific information regarding

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[276] See supra P 779.

[277] Order No. 890 at P 196.

[278] The NERC glossary defines "interchange" as "Energy transfers that cross Balancing Authority boundaries." NERC Glossary at 9.

each transaction must be identified in an accompanying electronic label, known as a "Tag" or "e-Tag" which is used by affected reliability coordinators, transmission service providers and balancing authorities to assess the transaction for reliability impacts. Communication, submission, assessment and approval of a Tag must be completed for reliability consideration before implementation of the transaction.

a. Interchange Authority

796. The Version 1 INT Reliability Standards submitted with NERC's August 28, 2006 supplemental filing include a new entity, the interchange authority, which oversees interchange transactions and is included as an applicable entity or referenced in the Requirements sections of INT-005-1, INT-006-1, INT-007-1, INT-008-1, INT-009-1 and INT-010-1.[279] The Commission requested in the NOPR that NERC provide additional information regarding the role of the interchange authority so that the Commission could determine whether the interchange authority is a user, owner or operator of the Bulk-Power System required to comply with mandatory Reliability Standards.

i. Comments

797. ISO-NE states that it is unclear who the interchange authority should be, how its tasks could be performed operationally and how the interchange authority function relates to other reliability and market functions. ISO-NE states that NERC has not yet fully incorporated the concept of an interchange authority into its Functional Model and has not provided a means for an entity to register as an interchange authority under the Functional Model. Finally, ISO-NE states that NERC must still create a process to allow the appropriate entities to register as interchange authorities so that their status is clear to all applicable entities, and it urges that approval of the Reliability Standards that have the interchange authority as an applicable entity be withheld until these issues are resolved.

798. APPA agrees that applicability of the Reliability Standards to the interchange authority is confusing. However, APPA suggests the best approach to the problem is for NERC to identify the source and sink balancing authorities as the applicable entity in these Reliability Standards until the Functional Model is revised to better specify the status and responsibility of interchange authorities.

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[279] The NERC Glossary defines an "interchange authority" as "the responsible entity that authorizes implementation of valid and balanced Interchange Schedules between Balancing Authority Areas, and ensures communication of Interchange information for reliability assessment purposes." Id.

799. EEI observes that there is considerable confusion throughout the industry regarding the registration process and the relationship between registration and applicability of standards, with the interchange authority being an example of that confusion. However, EEI states it understands that the role of an interchange authority is currently being addressed and revisions to the Functional Model are currently moving through the approval process. If Version 3 of the Functional Model is approved by the NERC Board, EEI believes it will clarify that a sink balancing authority performing a Tag authority service could serve as an interchange authority and this modification would address the Commission's concern.

800. The CAISO suggests that it is premature to place any INT Reliability Standards involving an interchange authority into effect until more information is provided concerning the interchange authority's role.

ii. Commission Determination

801. The NERC glossary definition of interchange authority indicates that it is intended to provide essentially a quality control function in verifying and approving interchange schedules and communicating that information. Our understanding is that, in the interim, sink and source balancing authorities will serve as interchange authorities until the ERO has further clarified an interchange authority's role and responsibility in the modification of the Functional Model and in the registration process. The new interchange authority function allows an entity other than a balancing authority to perform this function in the future; the pre-existing INT-001-1 Reliability Standard identified the balancing authority as the responsible entity to perform this function. Any such entity should be registered by the ERO in the ERO compliance registry, so that the responsibility of an entity, other than a balancing authority, that takes on this role in the future would be clear.

802. In short, there is sufficient clarity concerning the nature and responsibilities of this function for it to be implemented at this time. Withholding approval of INT Reliability Standards pending further clarification on this matter would create an unnecessary gap in the coverage of the Reliability Standards that potentially could threaten the reliability of the Bulk-Power System.

b. Interchange Information (INT-001-2)

803. INT-001-1 seeks to ensure that interchange information is submitted to the reliability analysis service identified by NERC.[280] This Reliability Standard applies to

[280] Currently, the reliability analysis service used by NERC is the Interchange Distribution Calculator.

purchasing-selling entities and balancing authorities. It specifies two Requirements that focus primarily on establishing who has responsibility in various situations for submitting the interchange information, previously known as transaction tag data, to the reliability analysis service identified by NERC. The Requirements apply to all dynamic schedules, delivery from a jointly owned generator and bilateral inadvertent interchange payback.

804. The Commission proposed in the NOPR to approve Reliability Standard INT-001-1 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of its regulations, the Commission proposed to direct NERC to submit a modification to INT-001-1 that: (1) includes Measures and Levels of Non-Compliance and (2) includes a Requirement that interchange information must be submitted for all point-to-point transfers entirely within a balancing authority area, including all grandfathered and "non-Order No. 888" transfers.[281]

805. The Commission also noted in the NOPR that certain Requirements of INT-001-0 that relate to the timing and content of e-Tags had been deleted in the Version 1 Reliability Standard. NERC indicated that these Requirements are business practices that would be included in the next version of the NAESB Business Practices. The Commission stated in the NOPR that NERC's explanation of this change was acceptable and proposed to approve INT-001-1 with the deletion of Requirements R1.1, R3, R4 and R5. However, the Commission also noted that NAESB had not yet filed the e-Tagging requirements as part of its business practices, and that if no such business practice has been submitted at the time of the Final Rule, the Commission may reinstate these Requirements in the Final Rule.

806. NERC submitted INT-001-2, which supersedes the Version 1 Reliability Standards, in its November 15, 2006 filing. INT-001-2 adds Measures and Levels of Non-Compliance to the Version 0 Reliability Standard. In this Final Rule, the Commission addresses INT-001-2, as filed with the Commission on November 15, 2006.

i. <u>Comments</u>

807. APPA states that NERC's submission of INT-001-2 on November 15, 2006 has fulfilled the Commission's proposed directive to include Measures and Levels of Non-Compliance in this Reliability Standard. APPA also states that, while it does not oppose NERC consideration of the Commission's proposed directive regarding the submission of interchange information for all point-to-point transfers entirely within a balancing

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[281] This Requirement was included in INT-001-0 as Requirement R1.2.

authority area, it does not understand the Commission's reliability concerns in this connection.

808. MidAmerican states that it favors the Commission's proposed directive to NERC for a modification of the Reliability Standard as a substantial improvement for reliability. Constellation supports this proposal and states that the proposal, together with other initiatives, such as OATT reform, represent additional steps to achieving not only Bulk-Power System reliability, but also a reduction of undue discrimination in transmission services.

809. NERC disagrees with the Commission's proposal to direct the submission of interchange information on all point-to-point transfers within a balancing area. NERC contends that this issue was discussed at great length in the Reliability Standards development process and the vast majority of commenters and voters agreed that such a requirement would have no merit from a reliability perspective. It also states that such data is not used today by the NERC interchange distribution calculator for reliability.[282] Finally, NERC concludes that while it may be appropriate for this issue to be reconsidered in revisions to the Reliability Standards, a Commission directive to include a requirement that the collective expertise and the consensus of the industry have determined to be unnecessary for reliability constitutes "setting the standard."

810. LPPC agrees with the Commission that Requirements R1.1, R3, R4 and R5 are good business practices, and it states that for this reason they should not be included in the Reliability Standards. These business practices should more appropriately be contained in NAESB standards, or perhaps the pro forma OATT.

811. ERCOT maintains that INT-001-1 is not appropriate for the ERCOT region. ERCOT states that it is a single balancing authority. To the extent that INT-001-1 requires tagging transfers within a single balancing authority, it cannot be applied to ERCOT as written because all point-to-point transfers within ERCOT are financial transactions only. ERCOT notes that it tags transfers outside the ERCOT region.

812. Allegheny states that the requirement to tag point-to-point transactions cannot be met in the PJM market where Tags are not used when a transaction's source and sink are

[282] The NERC glossary defines the interchange distribution calculator as "[t]he mechanism used by Reliability Coordinators in the Eastern Interconnection to calculate the distribution of Interchange Transactions over specific Flowgates. It includes a database of all Interchange Transactions and a matrix of the Distribution Factors for the Eastern Interconnection." NERC Glossary at 9.

within the PJM footprint. Such transactions are reported through the PJM eSchedule system, which already provides adequate information for the PJM region to conduct reliability and curtailment analyses. Allegheny states that there is no reliability gap in the PJM market arising from this issue.

813. Santa Clara submits that LSEs should be applicable entities under proposed revised INT-001-2 to ensure that they have adequate notice of the requirements of this Reliability Standard. It states that the actions of LSEs are implicated in Requirement R1 of this proposed Reliability Standard.[283]

ii. Commission Determination

814. The Commission approves INT-001-2 as a mandatory and enforceable Reliability Standard. In addition, we direct the ERO to develop modifications to the Reliability Standard through the Reliability Standards development process, as discussed below.

815. We agree with APPA that INT-001-2, submitted on November 15, 2006 includes Measures and Levels of Compliance, and we will not direct any further action regarding Measures and Levels of Compliance at this time.

816. MidAmerican and Constellation support the Commission's proposal that this Reliability Standard include a Requirement that interchange information must be submitted for all point-to-point transfers entirely within a balancing authority area, including all grandfathered and "non-Order No. 888" transfers. The Commission points out that unless these grandfathered and "non-Order No. 888" transfers are included in one of the INT Reliability Standards, they might not be subject to appropriate curtailment as necessary due to system conditions. Curtailments are determined using the interchange distribution calculator. Unless transactions internal to a balancing authority area are included in the calculator as we proposed, they are not recognized by the calculator and may never be curtailed. For instance, even if a transaction internal to a balancing authority area is non-firm and some inter-balancing authority trades are firm, the latter could be cut before the former, despite the curtailment priorities in the Order No. 888 tariff. While we recognize that most trades internal to a balancing authority area do not affect interchange, some do, since electricity flows do not necessarily follow the contract path.

[283] INT-001-2 Requirement R1 provides that the LSE and purchasing-selling entity shall ensure that arranged interchange is submitted to the interchange authority.

817. In addition, e-Tagging of such transfers was previously included in INT-001-0 and the Commission is aware that such transfers are included in the e-Tagging logs. In short, the practice already exists, but if this Requirement is removed from INT-001-2, no Reliability Standard would require that such information be provided. We therefore will adopt the directive we proposed in the NOPR and direct the ERO to include a modification to INT-001-2 that includes a Requirement that interchange information must be submitted for all point-to-point transfers entirely within a balancing authority area, including all grandfathered and "non-Order No. 888" transfers.

818. The Commission agrees with ERCOT's conclusion that the Reliability Standard does not apply to financial point-to-point transfers within the ERCOT region. This interpretation is consistent with the proposed INT Reliability Standards. Likewise, Allegheny's views on tagging point-to-point transactions within the PJM market are consistent with the proposed INT Reliability Standards.

819. With respect to Santa Clara's position that LSEs should be applicable entities under the Reliability Standard, the Commission notes that in situations where a LSE is securing energy from outside the balancing authority to supply its end-use customers, it would function as a purchasing-selling entity, as defined in the NERC glossary, and would be included in the NERC registry on that basis. This interpretation flows from the language of the Reliability Standards, and the Commission does not perceive any ambiguity in this connection. Nevertheless, the Commission directs the ERO to consider Santa Clara's comments, and whether some more explicit language would be useful, in the course of modifying INT-001-2 through the Reliability Standards development process.

820. The Commission accepts NERC's explanation that Requirements R1.1, R3, R4 and R5 of INT-001-0 that were deleted in INT-001-1 are business practices. NAESB voluntarily filed "Standards for Business Practices and Communication Protocols for Public Utilities" in Docket No. RM05-5-000 on November 16, 2006. This filing contains wholesales electric business practice standards that incorporate e-Tagging requirements and is the subject of a separate rulemaking process that is expected to result in rules that will become effective on or about the same time as the Reliability Standard becomes mandatory.

821. Accordingly, the Commission approves Reliability Standard INT-001-2 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification to INT-001-2 through its Reliability Standards development process that includes a Requirement that interchange information must be submitted for all point-to-

point transfers entirely within a balancing authority area, including all grandfathered and "non-Order No. 888" transfers.[284]

c. Regional Difference to INT-001-2 and INT-004-1: WECC Tagging Dynamic Schedules and Inadvertent Payback

822. NERC proposed a regional difference that would exempt WECC from requirements related to tagging dynamic schedules and inadvertent payback. The Commission noted in the NOPR that WECC is developing a tagging requirement for dynamic schedules. The Commission requested information from NERC on the status of the proposed tagging requirement, the time frame for its development, its consistency with INT-001-1 and INT-004-1 and whether the need for an exemption would cease when the tagging requirements become effective. The Commission stated that it would not approve or remand an exemption until NERC submits this information.[285] Rather, we stated that we would consider any regional differences contained in a proposed WECC tagging requirement for dynamic schedules when submitted by NERC for Commission review.

i. Comments

823. APPA agrees with the Commission's proposed course of action addressing this regional difference.

824. Xcel requests that the Commission accept the proposed regional difference; tagging requirements for dynamic schedules do not apply now in WECC, and it would be burdensome and would provide little reliability benefit to apply those requirements to WECC by June 2007. The Commission therefore should approve the proposed variance for an interim period until WECC's tagging requirements for dynamic schedules are developed and approved.

ii. Commission Determination

825. The Commission stressed in Order No. 672 that uniformity of Reliability Standards should be the goal and practice, "the rule rather than the exception."[286] The Commission therefore stated in the NOPR that the absence of a tagging requirement for

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[284] The Requirement was included in INT-001-0 as Requirement R1.2.

[285] To date, the Commission has not received the requested information.

[286] Order No. 672 at P 290.

dynamic schedules in WECC is a matter of concern, and that for this reason it could not approve or remand this regional difference without the additional information it requested. To date the Commission has not received this information. Of particular importance in this compliance filing will be the ERO's demonstration that this practice is due to a physical difference in the system or results in a more stringent Reliability Standard. Without this information, we are unable to address Xcel's comments further. The Commission therefore directs the ERO to submit a filing within 90 days of the date of this order either withdrawing this regional difference or providing additional information.

d. Regional Difference to INT-001-2 and INT-003-2: MISO Energy Flow Information

826. NERC proposed a regional difference that would allow MISO to provide market flow information in lieu of tagging intra-market flows among its member balancing authorities; the MISO energy flow information waiver is needed to realize the benefits of locational marginal pricing within MISO while increasing the level of granularity of information provided to the NERC TLR Process. The waiver request text states that it is understood that the level of granularity of information provided to reliability coordinators must not be reduced or reliability will be negatively affected. The waiver request text includes a condition specifying that the "Midwest ISO must provide equivalent information to Reliability Authorities as would be extracted from a transaction tag." The Commission proposed in the NOPR to approve this regional difference. It explained there that, based on the information provided by NERC, the proposed regional difference is necessary to accommodate MISO's Commission-approved, multi-control area energy market. Thus, the Commission stated it believed that the regional difference is appropriate, because it is more stringent than the continent-wide Reliability Standard and otherwise satisfies the statutory standard for approval of a Reliability Standard.

i. Comments

827. APPA agrees with Commission's proposed course of action in approving this regional difference.

ii. Commission Determination

828. The information received by the Commission demonstrates that the proposed regional difference to INT-001-2 and INT-003-2, as filed on November 15, 2006, is necessary to accommodate MISO's Commission-approved, multi-control area energy market. The Commission concludes that the regional difference is appropriate, because it is more stringent than the continent-wide Reliability Standard and otherwise satisfies the

statutory standard for approval of a Reliability Standard, and therefore approves it as mandatory and enforceable.

e. Interchange Transaction Implementation (INT-003-2)

829. The purpose of INT-003-1 is to ensure that balancing authorities confirm interchange schedules with adjacent balancing authorities before implementing the schedules in their area control error equations. INT-003-1 contains a Requirement that focuses on ensuring that a sending balancing authority confirms interchange schedules with its receiving balancing authority before implementing the schedules in its control area. The proposed Reliability Standard also requires that, for the instances where a high voltage direct current (HVDC) tie is on the scheduling path, both sending and receiving balancing authorities have to coordinate with the operator of the HVDC tie.

830. The Commission proposed in the NOPR to approve Reliability Standard INT-003-1 as mandatory and enforceable. In addition the Commission proposed to direct NERC to submit a modification to INT-003-1 that includes Measures and Levels of Non-Compliance.

831. NERC filed INT-003-2 with the Commission on November 15, 2006. This Reliability Standard supersedes the Version 1 Reliability Standard INT-003-1 and adds Measures and Levels of Non-Compliance.

i. Comments

832. APPA states that INT-003-2 fulfils the Commission's proposed directive to include Measures and Levels of Non-Compliance.

ii. Commission Determination

833. INT-003-1 serves an important purpose in requiring receiving and sending balancing authorities to confirm and agree on interchange schedules. With the addition of Measures and Levels of Non-Compliance, INT-003-2 addresses the Commission's only reservation regarding this Reliability Standard. Accordingly, the Commission approves Reliability Standard INT-003-2, as filed with the Commission on November 15, 2006, as mandatory and enforceable.

f. Regional Differences to INT-003-2: MISO/SPP Scheduling Agent and MISO Enhanced Scheduling Agent

834. NERC proposed a regional difference that would provide MISO and SPP with a variance from INT-003-1 to permit a market participant to use a scheduling agent to prepare a transaction Tag on its behalf.[287] In addition, NERC proposed the MISO Enhanced Scheduling Agent Waiver, whichcreates a variance from INT-003-1 for MISO that permits an enhanced single point of contact scheduling agent.

835. The Commission proposed in the NOPR to approve these two additional regional differences. The Commission explained that, based on the information provided by NERC, the proposed regional differences for this INT Reliability Standard would provide administrative efficiency, and provide equal or greater amounts of information to the appropriate entities as required in MISO's Commission-approved multi-control area energy market. The NOPR stated that the regional difference is appropriate because it is more stringent than the continent-wide Reliability Standard and otherwise satisfies the statutory standard for approval of a Reliability Standard.

i. Comments

836. APPA agrees with the Commission's proposed approval of these regional differences.

837. FirstEnergy states that it would be helpful if NERC clarified the function and effect of these waivers. FirstEnergy states that, where a specific task will be performed by another entity on behalf of the transferor, the transferor entity needs a delegation agreement, whereas in transferring a responsibility, the transferor entity needs a waiver. FirstEnergy states that currently balancing authorities are held accountable by regional reliability organizations for those functions the waivers transfer to the regional reliability organization. FirstEnergy suggests that NERC should clarify that, under these waivers, responsibility for complying with these Reliability Standards should be transferred to the RTOs that actually perform the tasks associated with these requirements.

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[287] NERC proposed three regional differences for INT-003-1 that would apply to MISO. One proposed regional difference was addressed in Reliability Standard INT-001-1. The remaining two are discussed here.

ii. Commission Determination

838. These two variances from INT-003-2, as filed with the Commission on November 15, 2006, permit a market participant to use a scheduling agent to prepare a transaction tag on its behalf, providing administrative efficiency and providing equal or greater amounts of information to the appropriate entities as required in MISO's Commission-approved multi-control area energy market. This regional difference is appropriate because it is more stringent than the continent-wide Reliability Standard and otherwise satisfies the statutory standard for approval of a Reliability Standard. The Commission therefore approves the MISO/SPP Scheduling Agent Waiver and the MISO Enhanced Scheduling Agent Waiver as mandatory and enforceable regional differences to INT-003-2.

839. FirstEnergy may raise its suggestions in the Reliability Standards development process. However, we find that FirstEnergy's suggestion does not affect our decision to approve these two regional differences.

g. Dynamic Interchange Transaction Modifications (INT-004-1)

840. INT-004-1 seeks to ensure that dynamic transfers are adequately tagged to be able to determine their reliability impact. It requires the sink balancing authority, i.e., the balancing authority responsible for the area where the load or end-user is located, to communicate any change in the transaction. It also requires the updating of Tags for dynamic schedules.

841. In the NOPR, the Commission proposed to approve Reliability Standard INT-004-1 as mandatory and enforceable. The Commission also proposed to direct NERC to submit a modification to INT-004-1 that includes Levels of Non-Compliance.

i. Comments

842. APPA agrees with the Commission that INT-004-1 can be approved as a mandatory and enforceable Reliability Standard. However, it suggests that the missing Levels of Non-Compliance should be developed and submitted for Commission approval before penalties are levied for violations.

ii. Commission Determination

843. As explained in the NOPR, while the Commission has identified concerns with regard to INT-004-1, this proposed Reliability Standard serves an important purpose by setting thresholds on changes in dynamic schedules for which modified interchange data must be submitted. Further, the Requirements set forth in INT-004-1 are sufficiently

clear and objective to provide guidance for compliance. Accordingly, the Commission approves Reliability Standard INT-004-1 as mandatory and enforceable. In addition, the Commission directs the ERO to consider adding these Measures and Levels of Non-Compliance to the Reliability Standard.

h. Interchange Authority Distributes Arranged Interchange (INT-005-1)

844. INT-005-1 seeks to ensure the implementation of interchange between source and sink balancing authorities and that interchange information is distributed by an interchange authority to the relevant entities for reliability assessments.

845. The Commission proposed in the NOPR to approve Reliability Standard INT-005-1 as mandatory and enforceable. The Commission also proposed to direct NERC to submit a modification to INT-005-1 that includes Levels of Non-Compliance. Further, the Commission noted that INT-005-1 is applicable to the "interchange authority" and requested that NERC provide additional information regarding the role of the interchange authority so that the Commission can determine whether it is a user, owner or operator of the Bulk-Power System that is required to comply with mandatory Reliability Standards.

i. Comments

846. Comments on the interchange authority have been discussed above under the heading "INT Reliability Standards General Issues." No other comments on INT-005-1 have been submitted.

ii. Commission Determination

847. The Commission has set forth above its analysis and conclusion on interchange authorities. Our understanding is that, in the interim, source and sink balancing authorities will serve as interchange authorities until the ERO has clarified the role and responsibility of an interchange authority in the modification of the Functional Model and in the registration process.

848. The Commission is satisfied that the Requirements of INT-005-1 are appropriate to ensure that interchange information is distributed timely and available for reliability assessment. Accordingly, the Commission approves Reliability Standard INT-005-1 as mandatory and enforceable. In addition, the Commission directs the ERO to consider adding additional Measures and Levels of Non-Compliance to the Reliability Standard.

i. **Response to Interchange Authority (INT-006-1)**

849. INT-006-1 applies to balancing authorities and transmission service providers, and requires these entities to evaluate the energy profile and ramp rate of generation that supports interchange transactions in response to a request from an interchange authority to change the status of an interchange from an arranged interchange transaction to a confirmed interchange.

850. The Commission proposed in the NOPR to approve Reliability Standard INT-006-1 as mandatory and enforceable. In addition, the Commission proposed to direct NERC to submit a modification to INT-006-1 that: (1) makes it applicable to reliability coordinators and transmission operators and (2) requires reliability coordinators and transmission operators to review composite transactions from the wide-area reliability viewpoint and, where their review indicates a potential detrimental reliability impact, communicate to the sink balancing authorities necessary transaction modifications before implementation.

i. **Comments**

851. APPA agrees that INT-006-1 is sufficient for approval as a mandatory and enforceable reliability standard. However, APPA states that the Commission should merely instruct NERC to respond to the Commission's concerns and refrain from directing NERC to make specific changes to the Reliability Standard; APPA states that while the changes the Commission proposes may be appropriate, it should be left to NERC's expertise and the Reliability Standards development process to address the Commission's concerns.

852. FirstEnergy agrees that it is appropriate for the reliability coordinator to be included in the applicability section. However, it argues that it is impracticable in large organized markets, such as those of MISO and PJM, for a local entity, such as a transmission operator, to review wide-area transactions, and it does not improve reliability to do so. Transactions occurring totally within the market operation are provided as part of network service net scheduled interchange.

853. EEI states that the "wide-area reliability impact" review envisioned by the Commission, which involves review of the composite energy interchange transactions, probably already takes place under Reliability Standards INT-005 through INT-009 in a cost-effective manner. EEI explains that since most transactions submitted by wholesale markets to the transactions tagging process span multiple hours with varying sizes (in MW), and are often submitted days before transaction start times, the wide-area review consists of ensuring that sufficient generator ramping capability exists, as well as examining for limits on transfer capabilities. This review is generally considered

sufficient to the extent that analyses are taking place on the basis of projected system conditions. EEI suggests that the Commission-proposed review and validation of composite energy interchange transactions by reliability coordinators might be more effectively addressed through "near real-time" system review. It explains that, at this time, the broad range of system condition parameters is better known, and the reliability coordinators can make use of the TLR process to maintain system reliability.

854. Entergy disagrees with the Commission's proposed modifications. It contends that they will require substantial changes to the tagging specifications. Entergy believes that the Commission's concerns may already be addressed by Reliability Standards INT-005 through INT-009.

855. MISO believes the Reliability Standards and e-Tag specifications already require reliability entities to evaluate and approve e-Tags. It questions the value of specifying reliability coordinators and transmission operators as applicable entities because their responsibilities are already laid out in the Reliability Standards.

856. Northern Indiana contends that the NOPR's discussion of INT-006-1 is unclear and confusing. It states that it does not understand what the Commission means by "validate" when the Commission proposes that reliability coordinators and transmission operators review and validate composite arranged interchanges. Northern Indiana also questions whether both reliability coordinators and transmission operators would be required to validate and approve the Tags and what the basis for approval would be. It questions what falls within the term "potential detrimental reliability impact," what happens if a Tag is not validated within 20 minutes to the hour, and whether all schedules are canceled outright or passively approved.

857. TVA suggests that the term "composite Tag" should be defined as part of the proposed modifications. CAISO also questions the meaning of "composite Tag" and seeks clarification on that issue. TVA notes that depending on the type of reliability analysis required to validate a "composite Tag," it may prove impractical to conduct this evaluation for hourly transactions.

858. CAISO states that neither NERC nor the Commission has identified a deficiency in the current interchange reliability assessment process or a pressing reliability need for this Reliability Standard. CAISO also has concerns about meeting the Commission-proposed directives regarding INT-006-1 since reliability coordinators and transmission operators within the Western Interconnection currently do not have a common database from which to draw the information needed to review composite transactions from a wide-area reliability viewpoint. CAISO requests the Commission to consider whether the Western Interconnection should comply with these proposed Requirements at all or whether a transition period is appropriate.

ii. Commission Determination

859. The Commission approves INT-006-1 as mandatory and enforceable. In addition, we direct that NERC develop modifications to the Reliability Standard, as discussed below.

860. The Commission remains convinced that a proactive approach is superior to a reactive approach in maintaining system reliability. While EEI and Entergy claim that reliability coordinators and transmission operators' involvement in reliability reviews of interchange transactions are covered in INT-005 through INT-010, and MISO claims that such review is covered in other Reliability Standards, we note the following: References to reliability coordinator and transmission operator involvement are virtually absent from the INT Reliability Standards. One finds such references only in Requirement R2 of INT-010, which deals with interchange coordination exemptions, and there the involvement of reliability coordinators is restricted to situations that involve current or imminent reliability-related reasons for action. We cannot find any Requirements in the remaining INT Reliability Standards that require a wide-area reliability assessment, regardless of the time periods, by a reliability coordinator; wide-area reliability assessment, moreover, can only be carried out by reliability coordinators.

861. With respect to MISO's comment on the value of applying the Reliability Standard to reliability coordinators and transmission operators given that the Reliability Standards and the e-Tag specification already require evaluation and active approval of reliability entities on e-Tags, we note that none of the INT Reliability Standards have those requirements and that the e-Tag specification is not part of the mandatory Reliability Standards. Like reliability coordinators who are responsible for reliable operation of entire reliability coordinator areas, a transmission operator is the reliability entity responsible for its local area operations. Interchange transactions would be likely to reduce system reliability if those transactions are not reviewed and approved by the appropriate reliability entities before implementation.

862. With respect to the question raised by TVA and CAISO on the definition of "composite Tags," we expressed our reliability concerns in the NOPR and explained that reliability coordinators and transmission operators should review composite energy interchange transaction information (composite Tags) for wide-area reliability impact. In addition, we stated that when the review indicated a potential detrimental reliability impact, the reliability coordinator or transmission operator should communicate to the sink balancing authority the necessary transaction modifications before

implementation.[288] While we did not require a specific notification time prior to actual transactions, this proactive approach should promote system reliability.

863. We agree with FirstEnergy that it is appropriate to include reliability coordinators as applicable entities for purposes of conducting wide-area reliability assessments; in large organized markets transmission operators may not be appropriate for this purpose because they do not have a wide-area view.

864. While we did not address review time frames in the NOPR, we are in general agreement with EEI's suggestion that "near-real time" system review by reliability coordinators may be more practical, while still being efficient and effective in achieving reliability goals. A proactive approach, i.e. one that involves reliability coordinators in a way that permits them to make wide-area assessments of composite interchange transactions for purposes of evaluating reliability impact, including identifying potential IROL violations and mitigating them using TLR procedures before they become actual IROL violations, is far superior to a reactive approach, i.e., one that brings reliability coordinators in after the fact to invoke TLR procedures to avoid an IROL violation or other operating actions to extricate the system from reliability problems such as an actual IROL violation.

865. The Commission stated in Order No. 672 that it expected entities to use the Reliability Standards development process to address their concerns about a Reliability Standard. With respect to CAISO's request that the Commission consider whether the Western Interconnection needs to comply with these Requirements at all or whether a transition period is appropriate, since CAISO did not raise either concern in the Reliability Standards development process, and others in the Western Interconnection have not raised a similar concern, CAISO should raise this issue in the Reliability Standards development process in the first instance. Reliability Standard INT-006-1 will apply to CAISO.

866. Accordingly, the Commission approves Reliability Standard INT-006-1 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification to INT-006-1 through the Reliability Standards development process that: (1) makes it applicable to reliability coordinators and transmission operators and (2) requires reliability coordinators and transmission operators to review energy interchange transactions from the wide-area and local area reliability viewpoints respectively and, where their review indicates a potential detrimental reliability impact, communicate to the sink balancing authorities necessary transaction modifications before implementation.

[288] NOPR at P 219.

We also direct that the ERO consider the suggestions made by EEI and TVA and address the questions raised by Entergy and Northern Indiana in the course of the Reliability Standards development process.

j. Interchange Confirmation (INT-007-1)

867. Reliability Standard INT-007-1 requires that before changing the status of submitted arranged interchanges to confirmed interchanges, the interchange authority must verify that the submitted arranged interchanges are valid and complete with relevant information and approvals from the balancing authorities and transmission service providers. The Commission proposed in the NOPR to approve INT-007-1 as mandatory and enforceable.

i. Comments

868. APPA agrees with the Commission that INT-007-1 is sufficient for approval as a mandatory and enforceable Reliability Standard, subject to NERC's plans for the registration of entities as interchange authorities.

ii. Commission Determination

869. The Commission approves Reliability Standard INT-007-1 as mandatory and enforceable. The Commission has set forth above its analysis and conclusion on interchange authorities. Our understanding is that in the interim source and sink balancing authorities will serve as interchange authorities until the ERO has clarified the role and responsibility of an interchange authority in the modification of Functional Model and in the registration process.

k. Interchange Authority Distribution of Information (INT-008-1)

870. INT-008-1 requires the interchange authority to distribute information to all balancing authorities, transmission service providers and purchasing-selling entities involved in the arranged interchange when the status of the transaction has changed from arranged interchange to confirmed interchange. The Commission proposed in the NOPR to approve INT-008-1 as mandatory and enforceable.

i. Comments

871. APPA agrees with the Commission that INT-008-1 is sufficient for approval as a mandatory and enforceable Reliability Standard, subject to NERC's plans for the registration of entities as interchange authorities. It suggests that NERC should clarify which reliability entities have the responsibility for ensuring that interchange information

is coordinated between the source and sink balancing authorities before implementing the Reliability Standard. APPA also states that NERC should modify this Reliability Standard to make clear what entities it in fact would apply to.

ii. <u>Commission Determination</u>

872. The Commission approves Reliability Standard INT-008-1 as mandatory and enforceable. The Commission has set forth above its analysis and conclusion on interchange authorities. Our understanding is that a source and sink balancing authority will serve as the interchange authority until the ERO has clarified the role and responsibility of an interchange authority in the modification of the Functional Model and in the registration process. Finally, we direct the ERO to consider APPA's suggestions in the Reliability Standards development process.

l. <u>Implementation of Interchange (INT-009-1)</u>

873. Reliability Standard INT-009-1 seeks to ensure that the implementation of an interchange between source and sink balancing authorities is coordinated by an interchange authority. The Commission proposed in the NOPR to approve INT-009-1 as mandatory and enforceable.

i. <u>Comments</u>

874. APPA agrees with the Commission that INT-009-1 is sufficient for approval as a mandatory and enforceable Reliability Standard, subject to NERC's plans for the registration of entities as interchange authorities. It suggests that NERC modify its Functional Model to clarify which reliability entities have the responsibility for ensuring proper implementation of interchange transactions that have received reliability assessments. APPA also suggests that NERC modify this Reliability Standard to make clear what entities it in fact would apply to.

ii. <u>Commission Determination</u>

875. The Commission approves Reliability Standard INT-009-1 as mandatory and enforceable. The Commission has set forth above its analysis and conclusion on interchange authorities. Our understanding is that a source and sink balancing authority will serve as the interchange authority until the ERO has clarified the role and responsibility of an interchange authority in the modification of the Functional Model and in the registration process. Finally, we direct the ERO to consider APPA's suggestions concerning this Reliability Standard in the Reliability Standards development process.

m. Interchange Exemptions (INT-010-1)

876. INT-010-1 allows reliability entities to initiate or modify certain types of interchange schedules under abnormal operating conditions and to be exempt from compliance with other INT Reliability Standards.

877. The Commission explained in the NOPR that Reliability Standard INT-010-1 includes provisions that allow modification to an existing interchange schedule or submission of a new interchange schedule that is directed by a reliability coordinator to address current or imminent reliability-related reasons. The Commission interpreted these current or imminent reliability-related reasons as not including actual IROL violations, since they require immediate action so that the system can be returned to a secure operating state as soon as possible and no longer than 30 minutes after a reliability-related system interruption – a period that is much shorter than the time that is expected to be required for new or modified transactions to be implemented.

878. The Commission proposed to approve INT-010-1, interpreted as set forth above, as mandatory and enforceable.

i. Comments

879. Northern Indiana supports the Commission's interpretation of INT-010-1, but it requests that the Reliability Standard be modified to explicitly state that it does not include actual IROL violations.

880. ISO-NE supports Commission approval of INT-010-1, but does not share the Commission's concerns regarding the initiation or modification of interchange schedules to address SOL or IROL violations. It states that interchange schedules can in certain circumstances provide an additional effective tool to help prevent an SOL and IROL violation. While ISO-NE recognizes that other tools may in certain circumstances be more effective, it states that this neither diminishes the value nor precludes the use of the tools contained in INT-010-1. ISO-NE also notes that section 2.4 of INT-010-1, which describes Level 4 Non-Compliance, should be edited to state that "[t]here shall be a level four non-compliance. . . " instead of "[t]here shall be a level three non-compliance. . . ."

881. APPA agrees with the Commission that INT-010-1 is sufficient for approval as a mandatory and enforceable Reliability Standard, but APPA does not agree with the Commission's interpretation of the Reliability Standard. APPA explains that the stated purpose of INT-010-1 is to allow certain types of interchange schedules to be initiated or modified by reliability entities and to be exempt from compliance with other interchange standards under abnormal operating conditions. This Reliability Standard in effect authorizes reliability coordinators to direct, and balancing authorities to take, remedial

actions to adjust interchange schedules immediately and then document these actions after the fact. INT-010-1 thus provides the emergency waiver from other INT Reliability Standards that makes adjusting interchange schedules the appropriate response to a SOL or IROL. APPA states that the Commission's proposed interpretation therefore should not be adopted.

882. EEI cautions against adopting the Commission's interpretation of INT-010-1. EEI believes that the existing standard meets the Commission's expectation, i.e., permitting and encouraging immediate action to alleviate an SOL or IROL. EEI explains that without INT-010-1, all interchange scheduling and schedule modifications would go through the normal process contained in INT-005 through INT-009. Only INT-010 would allow a balancing authority to make an immediate interchange action without obtaining a Tag. Within 60 minutes of the action, the balancing authority would follow up with the necessary documentation and carry forward the action, if necessary. In the absence of INT-010-1, a balancing authority taking such action would be in violation of INT-009 for failing to comply with the normal process requirements.

883. EEI notes by way of example that, to relieve an SOL or IROL, a reliability coordinator requires immediate offsetting changes in the net scheduled interchange of ACE equations of source and sink balancing authorities. Within 60 minutes following the action, the reliability authority directs the balancing authority to reflect the schedule change event using an arranged interchange. The tagging activity ensures coordination going forward and provides a written record. All of this takes place after the operational tasks pertaining to the action to alleviate the SOL or IROL, consistent with Commission expectations.

ii. Commission Determination

884. For the reasons and interpretation noted in the NOPR, the Commission approves INT-010-1 as mandatory and enforceable.

885. The Commission believes that our interpretation of INT-010-1 is consistent with the way APPA and EEI understand the Reliability Standards. The Commission believes that making a modification to an existing interchange schedule on paper for current or imminent reliability-related situations involving actual IROL violations is ineffective because its implementation usually takes much longer than the 30 minutes period that is allowed in the relevant IRO or TOP Reliability Standards. However, the Commission interprets INT-010-1 as allowing the actual physical transaction to be modified to alleviate an IROL event without first documenting the modification. The interchange schedule would then be modified after the fact to document the physical actions taken.

886. With regard to ISO-NE's statement that interchange schedules can, in certain circumstances, provide an additional effective tool to help prevent SOL and IROL violations while other tools may, in certain circumstances, be more effective, the Commission clarifies that our concern is related to using interchange schedules to address actual IROL violations. We have no concern in using this as a tool help prevent potential SOL and IROL violations as asserted by ISO-NE. We further note that the phrase in Requirements R2 and R3 "current or imminent reliability-related reasons" can be interpreted as potential or actual IROL violations set forth in the comments from Northern Indiana, ISO-NE, APPA and EEI, and therefore modifications to INT-010-1 are needed.

887. Accordingly, the Commission approves Reliability Standard INT-010-1 as mandatory and enforceable. In addition, we adopt the interpretation set forth in the NOPR that these current or imminent reliability-related reasons do not include actual IROL violations, since they require immediate control actions so that the system can be returned to a secure operating state as soon as possible and no longer than 30 minutes after a reliability-related system interruption – a period that is much shorter than the time that is expected to be required for new or modified transactions to be implemented. Finally, we direct the ERO to consider Northern Indiana and ISO-NE's suggestions in the Reliability Standards development process.

7. <u>IRO: Interconnection Reliability Operations and Coordination</u>

888. The Interconnection Reliability Operations and Coordination (IRO) group of Reliability Standards detail the responsibilities and authorities of a reliability coordinator.[289] The IRO Reliability Standards establish requirements for data, tools and wide-area view, all of which are intended to facilitate a reliability coordinator's ability to perform its responsibilities and ensure the reliable operation of the interconnected grid.

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[289] According to the NERC glossary, at 15, a reliability coordinator is "the entity with the highest level of authority who is responsible for the reliable operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations…."

a. Reliability Coordination – Responsibilities and Authorities (IRO-001-1)

889. IRO-001-1 requires that a reliability coordinator have reliability plans, coordination agreements and the authority to act and direct reliability entities to maintain reliable system operations under normal, contingency and emergency conditions.

890. In November 2006, NERC submitted IRO-001-1, which includes Measures and Levels of Non-Compliance.[290] In addition, while the Version 0 Reliability Standard applied to reliability coordinators and regional reliability organizations, IRO-001-1 would in addition apply to transmission operators, balancing authorities, generator operators, transmission service providers, LSEs and purchasing-selling entities. The Version 1 Reliability Standard does not modify or add any Requirements, and it appears that the change in applicability corresponds to existing Requirement R8, which provides that transmission operators, balancing authorities, generator operators, transmission service providers, LSEs and purchasing-selling entities "shall comply with Reliability Coordinator directives unless such actions would violate safety, equipment, or regulatory or statutory requirements."

891. In the NOPR, the Commission proposed to approve the Reliability Standard as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission proposed to direct NERC to submit a modification to Requirement R1 of IRO-001-0 that: (1) reflects the process set forth in the NERC Rules of Procedures and (2) eliminates the regional reliability organization as an applicable entity.

i. Comments

892. APPA supports the approval of the Reliability Standard but expresses concern that the Version 1 standard does not include Measures that correspond to Requirements R2 and R9. APPA emphasizes the need for Measures corresponding to Requirement R9, which requires the reliability coordinator to act in the interests of reliability for the overall reliability coordinator area and the Interconnection before the interests of any other entity. APPA supports Requirement R8 with the extended applicability, provided that applicability is determined by reference to the NERC compliance registry. APPA agrees that the regional reliability organization should be eliminated as an applicable entity and suggests it be replaced with Regional Entities.

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[290] IRO-001-1 supercedes the Version 0 Reliability Standard. In this Final Rule, we review the November version, IRO-001-1.

893. FirstEnergy suggests that NERC clarify whether Requirement R8, which requires entities to comply with a reliability coordinator directive "unless such actions would violate safety, equipment or regulatory or statutory requirements," refers to personnel safety, equipment safety or both. In addition, it suggests the establishment of a chain of command so that, for example, if a generator receives conflicting instructions from a balancing authority and a transmission operator, it can determine which instruction governs.

894. Requirement R3 provides that a reliability coordinator "shall have clear decision-making authority to act and direct actions to be taken" by applicable entities to "preserve the integrity and reliability of the Bulk Electric System and these actions shall be taken without delay but no longer than 30 minutes." Santa Clara contends that some actions would require driving to a remote site and therefore, mandating completion of the required action within 30 minutes would be unreasonable. Thus, it recommends that NERC modify Requirement R3 to provide that "actions shall commence without delay, but in any event shall commence within 30 minutes."

895. California Cogeneration comments that the Reliability Standard fails to address the operational limitations of QFs because they have contractual obligations to provide thermal energy to their industrial hosts. It contends that a QF can be directed to change operations only in the case of a system emergency, pursuant to 18 CFR § 292.307.

ii. Commission Determination

896. In the NOPR, the Commission proposed to approve the Reliability Standard as mandatory and enforceable. In addition, as a separate action under section 215(d)(5), the NOPR proposed to direct the ERO to develop modifications to Requirement R1[291] to substitute "Regional Entity" for "regional reliability organization" and reflect NERC's Rules of Procedure for registering, certifying and verifying entities, including reliability coordinators. Commenters do not raise any concerns regarding the proposed action. Accordingly, for the reasons stated in the NOPR, the Commission approves IRO-001-1 as mandatory and enforceable. In addition, for the reasons discussed in the NOPR, the Commission directs the ERO to develop modifications to the Reliability Standard through the Reliability Standards development process that reflect the process set forth in

[291] Requirement R1 of IRO-001-1 provides that each regional reliability organization, "subregion" or "Interregional Coordinating group" shall establish one or more reliability coordinators to continuously assess transmission reliability and coordinate emergency operations. See NOPR at P 506.

the NERC Rules of Procedures and eliminate the regional reliability organization as an applicable entity.[292]

897. While APPA, FirstEnergy and California Cogeneration suggest possible changes to IRO-001-1, they do not suggest that the proposed Reliability Standard should not be approved. The ERO should consider the commenters' suggestions when modifying the Reliability Standard pursuant to its Reliability Standards development process. Further, the Commission directs the ERO to consider adding Measures and Levels of Non-Compliance in the Reliability Standard as requested by APPA.

898. However, we disagree with Santa Clara's suggested change regarding the 30-minute limit to implement a corrective control action in Requirement R3. When system integrity or reliability is jeopardized, e.g., exceeding IROLs or SOLs, the relevant reliability entities must take corrective control actions to return the system to a secure and reliable state as soon as possible and in no longer than 30 minutes. This is important to satisfy the relevant Reliability Standards such as IRO-005-0 and TOP-004-0 to minimize the amount of time the system operates in an insecure mode and is vulnerable to cascading outages.

b. Reliability Coordination – Facilities (IRO-002-1)

899. IRO-002-1 establishes the requirements for data, information, monitoring and analytical tools and communication facilities to enable a reliability coordinator to meet the reliability needs of the Interconnection, to act in addressing real-time emergency conditions and to control analysis tools.[293]

900. In the NOPR, the Commission proposed to approve the Reliability Standard as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission proposed to direct NERC to submit a modification that: (1) includes Measures and Levels of Non-Compliance and (2) modifies Requirement R7 to explicitly require a minimum set of tools for the reliability coordinator.

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[292] See NOPR at P 505-06.

[293] In its November 15, 2006, filing, NERC submitted IRO-002-1, which supercedes the Version 0 Reliability Standard. IRO-002-1 adds Measures and Levels of Non-Compliance to the Version 0 Reliability Standard. In this Final Rule, we review the November version, IRO-002-1.

i. Comments

901. Dominion agrees with the proposal to require a minimum set of tools for reliability coordinators, explaining that such specificity is needed to ensure that proactive efforts to maintain reliability are being continuously pursued. According to Dominion, a general requirement for "adequate" tools is insufficient and the proposal to modify IRO-002-1 is appropriate since it will ensure that operators have a minimum set of tools with which to perform their duties.

902. In contrast, both APPA and LPPC ask the Commission to reject the proposal to require a minimum set of tools because flexibility is needed to allow change as technology improves over time. LPPC states that the Commission should, instead, require a listing of capabilities that is not tied to a particular product or tool. APPA contends that, because the Measures now require the reliability coordinator to provide specifications to the Regional Entity to be in compliance, the Regional Entity will set the minimum standards for reliability tools. Further, according to APPA, setting a minimum requirement would establish a "lowest common denominator" that might prove counterproductive.

903. MRO states that IRO-002-0 is another Reliability Standard for which it will be difficult to identify Measures and Levels of Non-Compliance because the Requirements include terms like "adequate," "potential," "could result" and "as required."

ii. Commission Determination

904. NERC's November 2006 revision to the Reliability Standard satisfies the proposal to include Measures and Levels of Non-Compliance. While MRO comments that it will be difficult to identify Measures and Levels of Non-Compliance, it does not provide any specific suggestions for changes to NERC's proposal.

905. Further, consistent with the NOPR, the Commission directs the ERO to modify IRO-002-1 to require a minimum set of tools that must be made available to the reliability coordinator. We believe that this requirement will ensure that a reliability coordinator has the tools it needs to perform its functions. Further, as noted by Dominion, such a requirement promotes a more proactive approach to maintaining reliability.

906. With respect to the concerns of APPA and LPPC, the Commission clarifies that the Commission's intent is to have the ERO develop a requirement that identifies capabilities, not actual tools or products. The Commission agrees that the latter approach is not appropriate as a particular product could become obsolete and technology improves over time. We disagree with APPA that our concern is addressed by the new Measures

as they neither specify a minimum set of capabilities nor require any uniformity among reliability coordinators or Regional Entities. We do not believe that the identification of minimum capabilities translates to "lowest common denominator" as suggested by APPA. If the Reliability Standards development process results in developing a "lowest common denominator" Reliability Standard that is geared toward guaranteeing compliance and avoiding penalties as opposed to ensuring reliability, the Commission could remand such a Reliability Standard.[294]

907. We disagree with MRO that it will be difficult to identify Measures and Levels of Non-Compliance since the Requirements include terms like "adequate," "potential," "could result" and "as required." Many tariffs on file with the Commission do not specify every compliance detail, but rather provide some level of discretion as necessary to carry out a particular act. This does not mean the tariffs are unenforceable; rather, it means that, if a dispute arises over compliance and there is a legitimate ambiguity regarding a particular fact or circumstance, that ambiguity can be taken into account in the exercise of the Commission's enforcement discretion.

908. As we stated in the NOPR,[295] Reliability Standard IRO-002-1 serves an important purpose in ensuring that reliability coordinators have the information, tools and capabilities to perform their functions. The Measures and Levels of Non-Compliance submitted by NERC further enhance the Reliability Standard. Accordingly, the Commission approves Reliability Standard IRO-002-1 as mandatory and enforceable. In addition we direct the ERO to develop a modification to IRO-002-1 through the Reliability Standards development process that requires a minimum set of tools that should be made available to reliability coordinators.

c. Reliability Coordination – Wide Area View (IRO-003-2)

909. The purpose of IRO-003-2 is for a reliability coordinator to have a wide-area view of its own and adjacent areas to maintain situational awareness. Wide-area view also

[294] See Order No. 672 at P 329.

[295] NOPR at P 511.

facilitates a reliability coordinator's ability to calculate SOL and IROL as well as determine potential violations in its own area.[296]

910. In the NOPR, the Commission proposed to approve the Reliability Standard as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission proposed to direct NERC to submit a modification that includes: (1) Measures and Levels of Non-Compliance and (2) criteria to define the term "critical facilities" in a reliability coordinator's area and its adjacent systems.

i. Comments

911. APPA agrees that IRO-003-2 is sufficient for approval as a mandatory and enforceable Reliability Standard. However, APPA suggests that, instead of merely including criteria to define critical facilities as proposed, NERC and each Regional Entity should establish, document, use and make transparent the methodology, data and procedures they use to determine "critical facilities."

912. Entergy agrees with the need for the criteria, but cautions that it must be flexible enough to allow for changing conditions experienced in real-time operations. Xcel notes that the term "critical facilities" is not defined and suggests that the Reliability Standard not be approved until the term is defined.

ii. Commission Determination

913. For the reasons stated in the NOPR,[297] the Commission approves proposed Reliability Standard IRO-003-2 as mandatory and enforceable. NERC's November 2006 revision to the Reliability Standard satisfies the proposal to include Measures and Levels of Non-Compliance.

914. Further, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, we adopt in the Final Rule the proposal to direct that the ERO develop a modification to the Reliability Standard through the Reliability Standards development process to create criteria to define the term "critical facilities" in a reliability coordinator's area and its

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[296] In its November 15, 2006, filing, NERC submitted IRO-003-2, which supercedes the Version 0 Reliability Standard. IRO-003-2 adds Measures and Levels of Non-Compliance to the Version 0 Reliability Standard. In this Final Rule, we review the November version, IRO-003-2.

[297] See NOPR at P 519.

adjacent systems. In developing the required modification, the ERO should consider the suggestions of APPA, Entergy and Xcel.

d. Reliability Coordination – Operations Planning (IRO-004-1)

915. The purpose of IRO-004-1 is to require each reliability coordinator to conduct next-day operations reliability analyses to ensure that the system can be operated reliably in anticipated normal and contingency system conditions. Operations plans must be developed to return the system to a secure operating state after contingencies and shared with other operating entities.

916. In the NOPR, the Commission proposed to approve Reliability Standard IRO-004-1 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission proposed to direct NERC to submit a modification to IRO-004-1 that requires the next-day analysis to identify effective control actions that can be implemented within 30 minutes during contingency conditions.

i. Comments

917. APPA agrees that IRO-004-1 is sufficient for approval as a mandatory Reliability Standard and that the Requirements are sufficiently clear and objective to provide a basis for issuing a remedial action directive. However, it contends that many Requirements lack Measures and Levels of Non-Compliance, and the ERO and Regional Entities should not assess penalties until additional Measures and Levels of Non-Compliance are developed.

918. Entergy agrees that a mitigation plan for potential operating problems identified in the next-day analysis may be an appropriate requirement, but cautions that it would be inappropriate to penalize an entity that chooses an alternate mitigation strategy when the issues arise in real time based on system conditions prevalent at that time.

919. APPA, in contrast, disagrees with the proposed directive to identify effective control actions in the next-day analysis. It contends that real-time conditions are seldom the same as predicted in the day-ahead schedule, and state estimators using real-time operating conditions are much more accurate than analyses based on day-ahead schedules.

920. FirstEnergy contends that IRO-004-1 should require a day-ahead planning process and reflect activities inherent within a market operation.

921. Northern Indiana contends that the Commission's proposed directive is unclear. It asks whether the Commission is requiring the reliability coordinator to secure the

system to an N-2 state, rather than an N-1 state within the next-day planning analysis. It contends that currently the Reliability Standard is N-1, and requests clarification that the Commission did not intend to mandate an increase in security from N-1 to N-2 in the NOPR.

922. California PUC agrees that there is merit in requiring system operators to assess the outlook for the following day, but nevertheless is concerned with the Commission's proposed directive. Its main concern is that the list of identified control actions can be too long or too generic to be effective to address the myriad potential system contingencies that could arise on the next day.

923. California Cogeneration states that the proposed Reliability Standard allows reliability coordinators to require data on gross load and generation behind the site boundary meter, which is contrary to a prior Commission order.[298]

ii. Commission Determination

924. For the reasons stated in the NOPR,[299] the Commission approves proposed Reliability Standard IRO-004-1 as mandatory and enforceable. In addition, the Commission directs the ERO to develop modifications to the Reliability Standard, as discussed below.

925. We agree with Entergy that system operators must make their decision to use the most effective control action based on the prevailing system conditions, to return the system to a secure state following a contingency. Therefore, the chosen control action may be different than those identified in next-day operations planning. We reiterate that our intent is to require a comprehensive next-day operations planning study that includes identification of effective solutions to aid system operators in real-time operations.

926. We disagree with APPA's comment that day-ahead planning to identify effective control actions would not enhance system reliability because we believe this is also the intent of the ERO for including such a Requirement in this Reliability Standard.[300] Our

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[298] California Independent System Operator Corp., 96 FERC ¶ 63,015 at 7 (2001). It states in part "The intent of the Commission's directive was to remove the requirement to provide any behind-the-meter information, whether on generation or load."

[299] See NOPR at P 529.

[300] IRO-004-1 Purpose Statement states in part "Plans must be developed to alleviate SOL and IROL violations."

proposed directive is to augment the Requirement that the plans to alleviate SOL and IROL violations are assessed to ensure that the control actions can be implemented and effective within 30 minutes after a contingency.

927. We agree with APPA that state estimators and real-time contingency analyses using real-time operating conditions produce more accurate study results compared to those from next-day operations planning analyses that are based on day-ahead schedules and forecast conditions. However, we remain convinced that a proactive approach that includes identification of effective operating solutions to deal with contingencies is far superior to a reactive approach that identifies solutions when the system conditions prevail in real-time operations. The former can identify solutions that may not be otherwise available to the system operators – e.g. certain planned generation or transmission outages are approved conditional upon re-affirmation prior to their removal from service or a short recall time subject to certain system conditions developing in real-time operations.

928. We disagree with FirstEnergy that IRO-004-1 should include the day-ahead planning process and reflect activities inherent in a market operation because day-ahead planning includes financial activities that may not occur in real-time. The Commission believes that, for reliability purposes, the simulation should include only what will actually occur.

929. The proposed Reliability Standards IRO-005-1 and TOP-004-0 require that in the event of an IROL violation, i.e. power flow on an interface exceeding its IROL, the system must be returned to a secure state within 30 minutes regardless of the cause of the violation, so that the system is once again capable of withstanding the next contingency without resulting in cascading failures.

930. In response to Northern Indiana, our intent is not to mandate an increase in security from N-1 to N-2, but rather is to ensure there is no reliability gap in the IROL-related Reliability Standards. To do this, the Commission believes it is necessary to provide operators with control actions needed to mitigate an IROL violation while within the 30 minute period after a first contingency. We are not requiring an increase to N-2, which would require planning the system for any two contingencies at all times.

931. With respect to California PUC's comment, we note that it is just as important for day-ahead operation planners to review and derive system operating limits to deal with a myriad of contingencies for different system configurations and generation dispatches, as it is for them to assess the feasibility of returning the system to a secure operating state after these contingencies have occurred. Similar to reviewing and deriving SOLs and IROLs to ascertain that system reliability will be maintained based on the most onerous forecast conditions and critical contingencies, identifying corrective control actions

would not encompass each and every contingency and system condition. This is because previous operating experiences and established operating practices would have covered a significant portion of the contingencies and the corresponding control actions already.

932. We further note that for those few IROL contingencies under the forecast and most onerous system conditions, if operation planners equipped with a suite of off-line analytical tools, but without any burden, distraction or interference from real-time operations, cannot identify the effective control actions, it can be argued that it would be unrealistic to expect system operators to do so with an additional requirement – i.e. identification and implementation of an effective control action all within 30 minutes. In addition, the control actions identified in the next-day analysis may quite often provide relevant information to the system operators of the control options they have available.

933. We believe that our use of NERC's definition of bulk electric system in combination with its registration process should assuage California Cogeneration's concerns.

934. In response to APPA's concern that NERC did not provide a Measure for each Requirement, we reiterate that it is in the ERO's discretion whether each Requirement requires a corresponding Measure. The ERO should consider this issue through the Reliability Standards development process.

935. Accordingly, we approve Reliability Standard IRO-004-1 as mandatory and enforceable. Further, we direct the ERO to modify IRO-004-1 through the Reliability Standards development process to require the next-day analysis to identify control actions that can be implemented and effective within 30 minutes after a contingency. The Commission also directs the ERO to consider adding Measures and Levels of Non-Compliance to the Reliability Standard as requested by APPA.

e. Reliability Coordination – Current Day Operations (IRO-005-1)

936. IRO-005-1 ensures energy balance and transmission reliability for the current day by identifying tasks that reliability coordinators must perform throughout the day.

937. In the NOPR, the Commission proposed to approve Reliability Standard IRO-005-1 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission proposed to direct NERC to submit a modification to IRO-005-1 that includes Measures and Levels of Non-Compliance. The Commission proposed that the Measures and Levels of Non-Compliance specific to IROL violations should be commensurate with the magnitude, duration, frequency and causes of the violation. Further, the Commission proposed to direct the ERO to conduct

a survey on IROL practices and actual operating experiences, and indicated that it may propose further modifications to IRO-005-1 based on the survey results.[301]

i. Comments

938. FirstEnergy supports the approval of the proposed Reliability Standard as mandatory and enforceable as interpreted by NERC (i.e., that exceeding IROL for less than 30 minutes is not a violation), pending further action through the NERC Reliability Standards development process.

939. MidAmerican supports the Commission's proposed survey and notes that based on its experience, IROL violations have been faithfully reported across NERC.

940. The CAISO urges the Commission to proceed with caution if headed in the direction of absolute compliance with IROL. However, it supports the survey to determine the extent to which systems are actually "drifting" in and out of IROL limits.

941. APPA indicates its support of the Commission's directive to undertake a survey regarding IROL practices and experiences. However it feels that it should be NERC's role to decide on the survey. It contends that, based on the survey results and using the Reliability Standard development process, NERC would decide what modifications to IRO-005-2 are appropriate.

942. Entergy agrees that it is appropriate to use a mitigation plan to resolve an SOL or IROL violation when the actual contingency that causes an SOL or IROL violation is experienced. However, with an acceptable mitigation plan, it is not necessary to require transmission operators to keep facility loading below a level where a potential SOL or IROL violation would occur assuming a low probability of the contingency. Entergy requests clarification that the Commission's guidance is not intended to preclude the use of such alternative procedures. The Commission should be cautious not to restrictively define SOL or IROL in a manner that causes the system operator to take preemptive action through this Reliability Standard to address events that may technically be SOL or

[301] NOPR at P 545 ("We propose to direct NERC to perform a survey of present operating practices and actual operating experience concerning drifting in and out of IROL violations. As part of the survey, we will require reliability coordinators to report any violations of IROLs, their causes, the date and time of the violations, and the duration in which actual operations exceeded IROL to the ERO on a monthly basis for one year beginning two months after the effective date of the Final Rule.")

IROL violations, but which have a low probability of occurrence and can be mitigated through other proven procedures.

943. ISO-NE agrees that NERC should promptly address the ambiguities in the current definition of an IROL. It has a concern that the phrase "The Transmission Service Provider shall respect these SOLs and IROLs" in Requirement R14 may cause confusion that this entity is expected to respect SOLs and IROLs in the operating time frame.[302]

944. TAPS raises an issue with Requirement R13 that states in part "[i]n instances where there is a difference in derived limits,...Load-Serving Entities...shall always operate the Bulk Electric System to the most limiting parameter." TAPS further states that, since LSEs do not operate the system within SOLs or IROLs, the only thing such entities, particularly small ones, can do is shed load. It contends that if the Reliability Standard is mandatory, it should apply only within the parameters proposed by NERC—subject to its Bulk Electric System definition and its June registry criteria. Further, given the apparent error in the Reliability Standard, the Commission should ask NERC to re-examine it.

ii. Commission Determination

945. The Commission approves proposed Reliability Standard IRO-005-1 as mandatory and enforceable. In addition, the Commission directs the ERO to develop modifications to the Reliability Standard through the Reliability Standards development process, as discussed below.

946. The Commission clarifies the intent of and need for the proposed survey. We reiterate that the intent is to learn about the operating experiences and practices of operating entities; specifically, how they operate their systems to respect IROLs in the normal system conditions, i.e. prior to a contingency. The survey results will facilitate future development and modifications of IROL-related Reliability Standards to better clarify and eliminate potential multiple interpretations of respecting IROLs that may exist

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[302] IRO-005-1 Requirement R14 states "Each Reliability Coordinator shall make known to Transmission Service Providers within its Reliability Coordinator Area, SOLs or IROLs within its wide-area view. The Transmission Service Provider shall respect these SOLs or IROLs in accordance with filed tariffs and regional Total Transfer Calculation and Available Transfer Calculation processes."

in the proposed Reliability Standards.[303] In addition, the survey will identify the reliability risks and the frequency and number of operating practices involving drifting in and out of IROL.[304] The survey results will also provide guidance on the frequency, duration and magnitude of IROL violations, their causes and whether these IROL violations occur during normal or contingency conditions.

947. We note the support from FirstEnergy, MidAmerican, CAISO and APPA for our proposed survey. Regarding MidAmerican's comment that reporting on IROL violations is a routine practice, we note that the proposed Reliability Standards only require reporting on those violations that have exceeded IROLs for longer than 30 minutes. The current reporting requirements and results will not provide an adequate assessment of the existing operating practices regarding IROLs and the reliability risks and the extent of drifting in and out of IROLs.

948. In response to Entergy, the Commission believes that operating the system within IROL under normal system condition and exceeding IROL only after a contingency and subsequently returning the system to a secure condition as soon as possible, but no longer than 30 minutes, may be appropriate. This mode of operation will minimize the system risk of being one contingency away from potential cascading failures.

949. ISO-NE asks that the ERO should promptly clarify the current definition for IROL violations. However, we do not share ISO-NE's concern that transmission service providers may be responsible for respecting SOLs and IROLs in real-time operation. Requirement R14 only requires a transmission service provider to use the SOLs and IROLs provided by the reliability coordinator in its tariff, it does not require any action in the operating time frame.

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[303] NOPR at P 540: IRO-005-1 could be interpreted as allowing a system operator to respect IROLs in two possible ways: (1) allowing IROL to be exceeded during normal operations, i.e., prior to a contingency, provided that corrective actions are taken within 30 minutes or (2) exceeding IROL only after a contingency and subsequently returning the system to a secure condition as soon as possible, but no longer than 30 minutes. Thus, the system can be one contingency away from potential cascading failure if operated under the first interpretation and two contingencies away from cascading failure under the second interpretation.

[304] The term "drifting in and out of IROLs" refers to operating the normal system (i.e. prior to a contingency) with frequent occurrences in which IROLs are exceeded, but each occurrence lasting less than 30 minutes. Currently, this mode of operation is not considered as a violation of NERC Reliability Standards.

950. We do not share TAPS' concern regarding LSEs initiating load shedding as their own control action to respect IROLs or SOLs. The appropriate control actions to respect IROLs and SOLs are the responsibilities of a reliability coordinator and transmission operator. If load shedding is required, it is the responsibility of a reliability coordinator or a transmission operator to direct the appropriate entities including LSEs to carry it out. However, we urge the ERO to provide further clarification in this regard and include TAPS' concern in developing the modification of this Reliability Standard.

951. Accordingly, the Commission approves Reliability Standard IRO-005-1 as mandatory and enforceable. Further, because IRO-005-1 has no Measures or Levels of Non-Compliance, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to IRO-005-1 through the Reliability Standards development process that includes Measures and Levels of Non-Compliance. The Commission further directs that the Measures and Levels of Non-Compliance specific to IROL violations must be commensurate with the magnitude, duration, frequency and causes of the violations and whether these occur during normal or contingency conditions. Finally, the Commission directs the ERO to conduct a survey on IROL practices and actual operating experiences by requiring reliability coordinators to report any violations of IROL, their causes, the date and time, the durations and magnitudes in which actual operations exceeds IROLs to the ERO on a monthly basis for one year beginning two months after the effective date of the Final Rule. We may propose further modifications to IRO-005-1 based on the survey results.

f. Reliability Coordination – Transmission Loading Relief (IRO-006-3)

952. IRO-006-3 ensures that a reliability coordinator has a coordinated method to alleviate loadings on the transmission system if it becomes congested to avoid limit violations. IRO-006-3 establishes a detailed Transmission Loading Relief (TLR) process for use in the Eastern Interconnection to alleviate loadings on the system by curtailing or changing transactions based on their priorities and according to different levels of TLR procedures.[305] The proposed Reliability Standard includes a regional difference for reporting market flow information to the Interchange Distribution Calculator rather than tagged transaction information for the MISO and PJM areas. It also includes by reference the equivalent Interconnection-wide congestion management methods used in the WECC and ERCOT regions.

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[305] The equivalent Interconnection-wide transmission loading relief procedures for use in WECC and ERCOT are known as "WSCC Unscheduled Flow Mitigation Plan" and Section 7 of the "ERCOT Protocols," respectively.

953. In the NOPR, the Commission proposed to approve Reliability Standard IRO-006-3 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission proposed to direct NERC to submit a modification to IRO-006-3 that: (1) includes a clear warning that a TLR procedure is an inappropriate and ineffective tool to mitigate IROL violations; (2) identifies in a Requirement the available alternatives to use of the TLR procedure to mitigate an IROL violation and (3) includes Measures and Levels of Non-Compliance that address each Requirement. In addition, the Commission proposed to approve the WECC and ERCOT load relief procedures as superior to the national standard.

i. <u>Comments</u>

954. APPA agrees that IRO-006-3 is sufficient for approval as a mandatory Reliability Standard. It suggests that the ERO should consider development of detailed Measures and Levels of Non-Compliance that address each Requirement in IRO-006-3. Until then, penalties should not be imposed except for egregious violations and the associated penalties should be imposed by the Commission.

955. APPA, Entergy and MidAmerican agree that the TLR procedure is an inappropriate and ineffective tool to mitigate actual IROL violations and that a clear warning to that effect should be included. MidAmerican specifically suggests that the warning must also apply to actual emergency situations in addition to actual IROL violations.

956. Similarly, ISO-NE supports the Commission's conclusions with regard to reliance on TLRs to address actual IROL violations. Further, it supports the Commission's proposal that the ERO should modify the Reliability Standard to provide flexibility for ISOs and RTOs to rely on redispatch as a means to mitigate an IROL violation.

957. Xcel suggests that instead of the proposed modification of a clear warning, it should include a requirement that TLR procedures should not be used for alleviating actual IROL violations. It asserts that the latter approach would be more measurable than the Commission's proposed modification.

958. Entergy and MidAmerican believe that TLR procedures can be an effective mechanism to avoid potential SOL and IROL violations or potential emergency situations.

959. In contrast, Progress Energy disagrees with the Commission's reasoning on the ineffectiveness of using TLR procedures to alleviate actual IROL violations.

ii. Commission Determination

960. The Commission approves IRO-006-3 as mandatory and enforceable. In addition, we direct the ERO to develop modifications to the Reliability Standard as discussed below.

961. The Commission remains convinced, based on Blackout Recommendation No. 31,[306] the submissions from APPA, Entergy, MidAmerican, ISO-NE and Xcel, and NERC's comments on the Staff Preliminary Assessment,[307] that proposed directives to include a clear warning that a TLR procedure is an inappropriate and ineffective tool to mitigate IROL violations and to identify the available alternatives to use of the TLR procedure to mitigate an IROL violation are the appropriate improvements to address the deficiencies in using TLR procedures to mitigate actual IROL violations or actual emergency situations. The Commission endorses Blackout Recommendation No. 31.

962. The Commission agrees with Entergy and MidAmerican that TLR procedures can be an effective mechanism to avoid potential IROL violations and potential emergencies. Regarding this, we reiterate that our concerns have always been on the use of TLR to mitigate actual IROLs or actual emergencies, and not on potential IROLs or emergencies, as indicated in the Blackout Report, Staff Assessment and the NOPR.

963. We do not understand Progress Energy's disagreement because no reason is provided.

964. Accordingly, in addition to approving the Reliability Standard, the Commission directs the ERO to develop a modification to IRO-006-3 through the Reliability Standards development process that (1) includes a clear warning that the TLR procedure is an inappropriate and ineffective tool to mitigate actual IROL violations and (2) identifies in a Requirement the available alternatives to mitigate an IROL violation other than use of the TLR procedure. In developing the required modification, the ERO should consider the suggestions of MidAmerican and Xcel. In addition, the Commission

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[306] Blackout Recommendation No. 31, at 163 is to "Clarify that the transmission loading relief (TLR) process should not be used in situations involving an actual violation of an Operating Security Limit."

[307] The NERC comments to Staff Assessment at 49 state that "NERC agrees that the TLR procedure alone is usually not effective as a control measure to mitigate an IROL violation and explains that the TLR procedure was not intended to be effective in this manner."

approves the WECC and ERCOT load relief procedures as superior to the national Reliability Standard. As identified in the NOPR, the Commission directs the ERO to modify the WECC and ERCOT procedures to ensure consistency with the standard form of the Reliability Standards including Requirements, Measures and Levels of Non-Compliance.[308]

g. Regional Difference to IRO-006-3: PJM/MISO/SPP Enhanced Congestion Management (Curtailment/Reload/Reallocation)

i. Background

965. As explained in the NOPR, IRO-006-003 provides for a regional difference for MISO, PJM and SPP.[309] According to NERC, the regional difference is needed to allow RTO market practices, simplify transaction information requirements for market participants, and provide reliability coordinators with appropriate information for security analysis and curtailments, reloads, reallocations and redispatch requirements.

966. The regional difference to IRO-006-3 applies the congestion management process included in Joint Operating Agreements filed by MISO, PJM and SPP and specified in seams agreements reached among MISO, PJM, and their neighboring non-market areas during the RTOs' market formation and expansions. Under the congestion management process in the waiver, each RTO calculates an amount of energy (market flow) flowing across coordinated flowgates. These market flows are separated into their appropriate priorities based on the RTO's schedules and reservations and are available for curtailment under the appropriate TLR Levels in the NERC interchange distribution calculator. Under the TLR method for curtailing interchange transactions and in the per generator method for generation-to-load impacts, NERC uses a five percent curtailment threshold, but in the waiver, the RTO's market flows with an impact of greater than zero percent on a coordinated flowgate are represented and made available for curtailment under the appropriate TLR priorities.

967. In their comments on the Staff Preliminary Assessment, MISO-PJM contended that there is unduly discriminatory treatment of the market flows of MISO and PJM versus the generation-to-load impacts of non-market entities because the waiver subjects

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[308] See NOPR at P 564-65.

[309] NOPR at P 568.

the RTOs to curtailment (and the corresponding redispatch costs) in circumstances where the non-market entities would not be subject to curtailment.

968. In the NOPR, the Commission did not propose to approve or remand this regional difference.

ii. Comments

(a) Application of the Regional Difference

969. MISO-PJM contends that there is unduly discriminatory treatment against market flows of MISO and PJM during the application of the TLR Standard. The RTOs argue that NERC should modify IRO-006-3 and the MISO and PJM regional difference to require modifying the market flow threshold used by the interchange distribution calculator to assign relief obligations to MISO, PJM, and SPP from zero to a standard percentage that is technically feasible to implement on a non-discriminatory basis, netting of market flow impacts, tag impacts, and generation-to-load impacts, and reporting to the interchange distribution calculator all net generation-to-load impacts for both market and non-market transmission providers. Constellation supports MISO-PJM's argument that there is unduly discriminatory treatment of the MISO and PJM market flows compared to the generation-to-load impacts of non-market entities in the application of the TLR standard.

970. MISO-PJM indicates that they have raised the equity issue with the NERC Operating Reliability Subcommittee (Operating Subcommittee), that their markets currently are being asked to curtail market flow impacts down to zero percent while tagged transactions and generation-to-load impacts during TLR 5 are being asked to curtail impacts that are five percent or greater. MISO-PJM states that the NERC Operating Subcommittee has indicated that they will address reliability issues only and that they are not the appropriate group to address equity issues.

(b) Seams Agreements

971. Several entities argue that the Commission should not overturn the existing IRO-006-3 regional difference. MidAmerican states that MISO and PJM should continue to pursue a negotiated solution to the issues outlined in MISO-PJM's filings. Mid-Continent states that the Commission should reject the MISO-PJM proposal to require NERC to allow them to report only the transactions with five percent or greater impacts on flowgates rather than report all transactions for curtailments, since MISO and PJM offered to report all transactions to avoid negative impacts on the reliability of the transmission system. Mid-Continent argues that not doing so would impact the reliability of the transmission system.

972. Mid-Continent asks the Commission to not implement MISO and PJM's proposal to modify NERC's proceduresand to not override seams agreements. MidAmerican claims that MISO-PJM comments amount to an abrogation of existing seams agreements. MidAmerican states that the seams agreements were negotiated in a give-and-take process between the parties resulting in the existing waiver which was proposed by PJM and MISO in response to Commission orders. MidAmerican states that if any changes are sought to these waivers, they should be addressed in negotiation with the appropriate parties. MidAmerican suggests that any changes should be requested by way of the NERC process for developing Reliability Standards and that any negotiated agreements should be presented to the Commission for approval. Mid-Continent claims that MISO-PJM have not provided valid reasons to replace the current Reliability Standards or to take actions that would modify existing seams agreements signed by MISO and PJM. Mid-Continent asks the Commission not to short-circuit the NERC Reliability Standards process which will give full consideration to the reliability implications of MISO's and PJM's proposal.

973. APPA agrees with the Commission's proposed approach in allowing MISO, PJM, NERC and other "relevant entities" to continue their negotiations regarding this regional difference. APPA cautions that any agreement reached by NERC and approved by the Commission regarding a regional difference for this Reliability Standard should be governed by reliability considerations and should not permit market design considerations to override NERC's Reliability Standards. MidAmerican suggests a process where the RTOs invite parties to reconsider the seams agreements, the parties negotiate changes, the Commission approves new agreements and waivers are then sought from NERC to the extent necessary. MidAmerican argues that since the RTOs do not allege any reliability problem there is no need to reject or upend the existing NERC waiver.

(c) Modifying the Congestion Management Process and Alternatives for Temporary Application of the Waiver

974. Mid-Continent states that it agrees with the Commission's proposal to not adopt MISO and PJM's request to instruct NERC to modify the current waiver to the TLR in the RTOs and believes that instead the Commission should direct NERC to address these issues through the Reliability Standards development process with input from neighboring systems. Mid-Continent states that changes to the waiver must not discriminate against non-market regions; must not negatively impact the reliability of neighboring systems and must be consistent with seams agreements signed by the RTOs.

975. NRECA claims that issues associated with market flows and generation-to-load impacts have not been resolved and is concerned that MISO-PJM's suggestion that

"consensus" has been reached on the issues is premature. NRECA is also concerned that implementation of the MISO and PJM proposal could increase reliance on TLRs. NRECA urges the Commission to not short circuit or circumvent the Reliability Standards development process or the RTO stakeholders process and states that the Commission should permit the stakeholders to reach full consensus.

976. MISO-PJM indicates that they have been working with both the NERC Operating Subcommittee and the Congestion Management Process Working Group (Congestion Working Group) to achieve a consensus on these changes, and that based on this, the Commission stated in the NOPR that it prefers that MISO, PJM and others continue negotiations to resolve these issues rather than imposing a solution on market participants. MISO-PJM state that they have held extensive discussions with a group composed of NERC Operating Subcommittee and Congestion Working Group participants. MISO-PJM indicates that detailed analyses has been performed to evaluate the effect of changing the market flow threshold from zero percent to five percent in one percent increments and that the NERC Operating Subcommittee has recommended that the market flow threshold used by the interchange distribution calculator to assign relief obligations to the MISO, PJM, and SPP be changed from zero percent to three percent for a 12 month interim period. MISO-PJM assert that at the end of the 12 months, a decision will be made whether to recommend a permanent change to the market flow threshold from zero percent to three percent or a change to some other value. MISO-PJM state that according to the NERC Operating Subcommittee, this recommendation is to only address the reliability issue raised by MISO, PJM and SPP so that they are able to meet their relief assignment during TLR.

977. MISO-PJM also state sthat to receive congestion management process Council endorsement and support for the change being developed by the NERC Operating Subcommittee group, it requires unanimous approval by the congestion management process Council and that, though the 12 month field test to change the market flow threshold from zero percent to three percent has the support of MISO, PJM, SPP and TVA, it does not have the unanimous approval of all signatories to the seams agreements. MISO-PJM states that MAPPCOR (MAPP) has not agreed to the field test recommended by the NERC Operating Subcommittee and that MAPP has asserted that MISO should continue to honor their contractual obligation and report market flow impacts down to zero percent for relief assignments as specified in the MISO-MAPP Seams Operating Agreement. MISO is concerned that once the field test is complete and the NERC Operating Subcommittee recommends the use of a three percent threshold or some other threshold to address the reliability issue, the MISO may still have a contractual obligation with MAPP to use market flows down to zero percent for relief assignments. MISO-PJM states that this contractual obligation can only be altered if MISO and MAPP can agree on a change to the Seams Operating Agreement but expects resistance to change the

Seams Operating Agreement. MISO and PJM do not believe they can address the equity issue by continuing discussions with the NERC Operating Subcommittee.

978. MISO-PJM also state that by continuing to use market flows down to zero percent for relief assignments on reciprocally coordinated flowgates between MISO and MAPP, there will be situations where MISO is unable to meet its relief obligation. MISO-PJM states that they have sought unsuccessfully to execute redispatch agreements with those parties who have direct counter-flow on the identified flowgates where the MISO is unable to meet its relief obligation. MISO-PJM believe that the Commission should address this continuing discriminatory treatment of the market impacts on flowgates. MISO-PJM state that of the three areas where MISO-PJM raised comments on discriminatory treatment of the markets, only one area (changing the market flow threshold for a 12 month field test) has resulted in steps being taken to address the discriminatory treatment and that even this one area can only be considered a partial success because there is only a solution to address the reliability issue, but not the equity issue.

979. MISO-PJM explain in their supplemental comments that NERC has demonstrated a willingness to consider the reliability issue by authorizing a 12 month field test allowing PJM, MISO and SPP market flows to use a three percent threshold, to observe the impact on reliability, but will not address what it refers to as "equity issues." MISO-PJM explains the field test has been approved by all the reciprocal entities that have signed seams agreements except MAPP. MISO-PJM state that, at the end of the 12 months, a decision will be made whether to use a three percent threshold or some other threshold to address the reliability concerns. MISO-PJM explain that the same entities that make up the Mid-Continent objected to the field test because they asserted MISO has a contractual obligation under the MAPP Seams Operating Agreement to continue reporting its market flows down to zero percent. MISO-PJM contend that because the MISO has agreed to honor its contractual obligation during the field test and will continue to use a zero percent threshold for all flowgates that are reciprocal between MISO and MAPP, this means that the flowgates under the control of the Mid-Continent parties will not participate in the field test and NERC will have no data to show the impact of changing the market flow threshold to three percent on these flowgates.

980. MISO-PJM state that as long as the regional difference does not become a mandatory standard during the field test, they are satisfied that appropriate steps are being taken to address reliability.

(d) Reporting of Generator to Load Impacts by Non Market Areas

981. MISO-PJM supports modifications to the TLR process that would require all participants (both market and non-market) to report their market flow impacts and generator-to-load impacts to the interchange distribution calculator and honor their allocations when they report their firm versus their non-firm usage. MISO-PJM believes that taking this step would also address the threshold equity issue and the netting issue because all entities would be subject to the same treatment. MISO-PJM requests that the Commission to either direct NERC to initiate a process to modify the interchange distribution calculator such that market flows and generator-to-load impacts from non-market areas are both reported to the interchange distribution calculator and are subject to curtailment based on their priorities from the allocations or that the Commission take action to do so.

982. MISO-PJM states that the reporting of generator-to-load impacts by the non-market entities is the one area that is not currently under discussion with a stakeholder group. MISO-PJM explains that both the market and non-market entities receive an allocation on flowgates and that both the market entities and the non-market entities use the allocations when selling firm transmission service. MISO-PJM states that only the market entities report their market flows to the interchange distribution calculator and use their allocations to determine what portion of market flows will be considered firm and believe that the non-market entities could also report their firm and non-firm generator-to-load usage to the interchange distribution calculator and receive relief assignments based on this usage. MISO-PJM indicates that this would remove the assumption that all generator-to-load impacts from the non-market entities represent firm usage. MISO-PJM states that reporting relief obligations by one group of participants and not reporting by the other results in conflicting actions during the TLR process because market entities suffer the financial consequences of redispatch at the same time reliability is not being accomplished due to off-setting actions by non-market entities.

983. MISO-PJM states that, to address the discriminatory treatment of the markets, the Commission could order the TLR Reliability Standard to be modified to have the market entities discontinue reporting their market flows to the interchange distribution calculator. MISO-PJM believes that instead of this order, the preference is to have the market entities continue reporting their market flow impacts and the non-market entities report their generator-to-load impacts to the interchange distribution calculator. The allocations would be used to set the priority of these impacts.

984. Mid-Continent states that the regional difference requiring PJM and MISO to report all flows instead of net flows was part of the commitments MISO and PJM made to meet NERC's tagging requirements. Mid-Continent contends that it is appropriate to

treat MISO-PJM market flows differently because they are greater than the system flows that resulted from control area-based system operation. Mid-Continent further claims that MISO cannot achieve the redispatch the interchange distribution calculator requires because of MISO's own actions since MISO does not report actual flows to the interchange distribution calculator and MISO and PJM's congestion management tools do not utilize all redispatch options.

(e) Accounting for Counter Flows during TLR

985. MISO-PJM state that there have been discussions at the NERC Operating Subcommittee about taking into account counter-flows during TLR when assigning relief. MISO-PJM contend sthat by considering counter-flows, those entities that are responsible for the loading problem on a net basis will be responsible for fixing the loading problem during TLR. MISO-PJM states that the MISO, PJM and SPP markets operate on a net flow basis and, therefore, have additional reasons for wanting to consider counter-flows. MISO-PJM expects that by summer 2007, the Task Force will have a recommendation on netting in the interchange distribution calculator for the NERC Operating Subcommittee to consider. MISO-PJM state that it is premature to speculate on the outcome of the discussions with the NERC Operating Subcommittee at this time. MISO-PJM clarifies that they are not asking the Commission to take any action on this issue but to let the NERC Operating Subcommittee address the technical merits of netting impacts in the interchange distribution calculator.

986. Mid-Continent states that eliminating the requirements to report flows in both directions may adversely impact reliability because the interchange distribution calculator will not have enough information to assign responsibilities to the contributors of a constraint.

iii. Commission Determination

987. The Commission will not approve or remand this regional difference. The treatment of the market flows of MISO-PJM versus the generation-to-load impacts of non-market entities in the application of the TLR standard has been addressed by the Commission in a number of cases.[310] In approving the plans of various transmission owning utilities to join PJM, the Commission attached several conditions including a requirement that certain non-market utilities be held harmless from effects of loop flow

[310] See Alliance Companies, 100 FERC ¶ 61,137 (2001) and Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C., 106 FERC ¶ 61,251 (2004).

and congestion resulting from the utilities' RTO choices.[311] Further, during MISO's market start up,[312] the Commission determined that the markets could not start without the MISO having at least a specific, transparent plan for how it will handle the interface of multiple transmission tariffs and market-to-non-market seams[313] and required the MISO to file any resolution of seams, or a status report of progress on seams resolution including detailed plans as to how MISO will address seams absent agreements, within 60 days of the date of the order. The regional difference to IRO-006-3 applies the congestion management process that was included in the Joint Operating Agreement filed by MISO, PJM and SPP and that was specified in the seams agreements reached between MISO, PJM, and their neighboring non-market areas in order to meet the Commission's requirements described above.[314]

988. The Commission recognizes MISO-PJM's concerns that: (1) the congestion management process process could be placing an undue burden on the RTO regions to provide redispatch especially on remote flowgates where an RTO's dispatch has a small impact and (2) under the congestion management process, the calculation of market flows for relief assignments on Reciprocal Coordinated Flowgates between the MISO and MAPP could create situations where MISO is unable to meet its relief obligation without curtailing load. We also understand that these concerns are exacerbated by the possibility of civil penalties for non-compliance with the requirement to use market flows down to zero percent for relief assignments on reciprocal coordinated flowgates between MISO and MAPPCOR. Especially during transitions when markets with multiple control areas are started up, markets are expanded to include other control areas, or non-market control areas are consolidated, this can have an effect on the loop flows experienced by

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[311] Commonwealth Edison Company and American Electric Power Service Corporation, 106 FERC ¶ 61,250 (2004). This order required ComEd to demonstrate that its proposal held utilities in Wisconsin and Michigan harmless from all adverse impacts associated with loop flow or congestion that would result from its choice to join PJM.

[312] See Midwest Independent Transmission System Operator, Inc., 108 FERC ¶ 61,163 (2004).

[313] To resolve this issue, the Commission encouraged market participants to use the PJM-Midwest ISO joint operating agreement as a model or starting point for seams agreements, particularly with respect to the seams with the various utilities in the MAPP region.

[314] See Midwest Independent Transmission System Operator, Inc., 110 FERC ¶ 61,290 (2005).

neighboring regions and the redispatch required by the neighboring regions due to fewer tagged transactions reported to the interchange distribution calculator. The Commission recognizes that there are concerns by neighboring entities to be held harmless from increased redispatch responsibility caused by these transitions.

989. The Commission concludes that the issues described by MISO-PJM (i.e., defining the obligation of a certain region to provide redispatch when a flowgate becomes congested) are best handled through seams agreements rather than being subject to the NERC processes. We recognize that the two areas of seams agreements and Reliability Standards could overlap if the agreements reached do not allow for reliable outcomes where parties can achieve the relief assigned. As such, the Commission will neither approve nor remand the waiver of the regional difference to IRO-006-3 while the 12 month field test allowing PJM, MISO and SPP market flows to use a three percent threshold is being conducted. After the 12 month field test is complete, the Commission will reexamine approving the waiver as a mandatory and enforceable Reliability Standard.

990. The Commission instructs the RTOs to continue working with the non-market regions to develop revised seams agreements that allow for equitable and feasible treatment of market flows in the NERC TLR/redispatch process. The solution should not harm system reliability and should not subject either non-RTO transmission owners or the RTO markets to unreasonable redispatch responsibilities. We note that if consensus cannot be reached, the RTOs may file a section 205 or section 206 proposal to revise the terms and conditions of the congestion management process if the terms agreed on in the seams agreements and Joint Operating Agreement have become unjust or unreasonable or may file to terminate the agreements as allowed in the seams agreements.

991. The Commission will not adopt MISO-PJM's proposal to require non-market entities to report their generator-to-load impacts to the interchange distribution calculator with the allocations used to set the priority of these impacts in this Reliability Standards process. If NERC determines that this information and corresponding curtailment options are needed for reliability, NERC should file to modify IRO-006-3 to include these additions. However, the economic implications of the reporting of generator-to load impacts by non-market entities are not in the scope of the reliability process and are better addressed on a case-by-case basis or, as appropriate, in the proceeding on RTO Border Utility Issues.[315]

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[315] See RTO Border Utility Issues, Notice of Technical Conference on Seams Issues for RTOs and ISOs in the Eastern Interconnections (Docket No. AD06-9-000) (issued Jan. 25, 2007).

992. In addressing MISO-PJM's claim that the ERO should modify IRO-006-3 and the MISO-PJM regional difference to require netting generation-to-load impacts to recognize counterflow, we will let the ERO Operating Subcommittee address the technical merits of netting flow impacts in the interchange distribution calculator.

h. Procedures, Processes, or Plans to Support Coordination between Reliability Coordinators (IRO-014-1)

993. The stated purpose of IRO-014-1 is to ensure that each reliability coordinator's operations are coordinated so that they will not have an adverse reliability impact on other reliability coordinator areas and to preserve the reliability benefits of interconnected operation. Specifically, IRO-014-1 ensures energy balance and transmission by requiring a reliability coordinator to have operating procedures, processes or plans for the exchange of operating information and coordination of operating plans.

994. In the NOPR, the Commission proposed to approve IRO-014-1 as mandatory and enforceable.

i. Comments

995. APPA agrees with the Commission's proposed approval of IRO-014-1 as mandatory and enforceable.

ii. Commission Determination

996. For the reasons stated in the NOPR, the Commission approves IRO-014-1 as mandatory and enforceable.

i. Notifications and Information Exchange between Reliability Coordinators (IRO-015-1)

997. IRO-015-1 establishes Requirements for a reliability coordinator to share and exchange reliability-related information among its neighbors and participate in agreed-upon conference calls and other communication forums with adjacent reliability coordinators.

998. In the NOPR, the Commission proposed to approve IRO-015-1 as mandatory and enforceable.

i. Comments

999. APPA agrees with the Commission's proposed approval of IRO-015-1 as mandatory and enforceable.

ii. Commission Determination

1000. For the reasons stated in the NOPR, the Commission approves IRO-015-1 as mandatory and enforceable.

j. Coordination of Real-Time Activities between Reliability Coordinators (IRO-016-1)

1001. IRO-016-1 establishes Requirements for coordinated real-time operations, including: (1) notification of problems to neighboring reliability coordinators and (2) discussions and decisions for agreed-upon solutions for implementation. It also requires a reliability coordinator to maintain records of its actions.

1002. In the NOPR, the Commission proposed to approve IRO-016-1 as mandatory and enforceable.

i. Comments

1003. APPA agrees with the Commission's proposed approval of IRO-015-1 as mandatory and enforceable. However, it indicates that it is unclear in Level of Non-Compliance 2.1, how a reliability coordinator can demonstrate that it coordinated with other reliability coordinators without having retained evidence such as detailed logs or telephone recordings of having done so.[316]

ii. Commission Determination

1004. For the reasons stated in the NOPR, the Commission approves IRO-016-1 as mandatory and enforceable.

1005. We construe Level of Non-Compliance 2.1 as requiring evidence of coordination, but allowing flexibility on the type of evidence.

8. MOD: Modeling, Data, and Analysis

1006. The Modeling, Data and Analysis group of Reliability Standards is intended to standardize methodologies and system data needed for traditional transmission system

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[316] IRO-016-1 Level of Non-Compliance 2.1 states: "For potential, actual or expected events which required Reliability Coordinator-to-Reliability Coordinator coordination, the Reliability Coordinator did coordinate, but did not have evidence that it coordinated with other Reliability Coordinators."

operation and expansion planning, reliability assessment and the calculation of available transfer capability (ATC) in an open access environment. The 23 MOD Reliability Standards may be grouped into four distinct categories. The first category covers methodology and associated documentation, review and validation of Total Transfer Capability (TTC), ATC, Capacity Benefit Margin (CBM) and Transmission Reliability Margin (TRM) calculations.[317] The second category covers steady-state and dynamics data and models.[318] The third category covers actual and forecast demand data.[319] The fourth category covers verification of generator real and reactive power capability.[320]

1007. In the NOPR, the Commission proposed that one out of 23 MOD Reliability Standards be approved unconditionally, nine be approved with direction for modification and 13 remain pending with direction for modification.[321] The Commission, describing these 13 pending standards as fill-in-the-blank Reliability Standards, generally proposed to seek additional information before acting on them. Responding to CenterPoint's proposal to exempt ERCOT from the MOD Reliability Standards that address available transfer capability, the Commission explained that it would consider any regional difference at the time NERC submits one for Commission review. Therefore, the Commission stated that if ERCOT wished to request a regional difference, it should do so through the ERO process.

i. Comments

1008. ISO/RTO Council and ISO-NE agree with the Commission's proposal to neither approve nor remand the 13 MOD Reliability Standards until NERC supplies additional information. ISO/RTO Council and ISO-NE also recommend that the Commission go further and defer its approval of the MOD Reliability Standards that incorporate references to the 13 fill-in-the-blank Reliability Standards until those 13 are approved

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[317] MOD-001-0 through MOD-009-0.

[318] MOD-010-0 through MOD-015-0.

[319] MOD-016-0 through MOD-021-0.

[320] MOD-024-1 through MOD-025-1.

[321] Approved: MOD-018-0; approved with modification: MOD-06-0, MOD-007-0, MOD-010-0, MOD-012-0, MOD-016-1, MOD-017-0, MOD-019-0 through MOD-021-0; and pending: MOD-001-0 through MOD-005-0, MOD-08-0, MOD-09-0, MOD-011-0, MOD-013-1 through MOD-015-0, MOD-024-1 and MOD-025-1.

unconditionally. ISO/RTO Council and ISO-NE believe that the following Reliability Standards are dependent upon the 13 fill-in-the-blank standards: MOD-010-0, MOD-012-0, MOD-016-1, MOD-017-0, MOD-018-0, MOD-019-0, and MOD-021-0 and as such, the Commission should not approve and make them enforceable at this time. ISO-NE warns that these listed standards share the same infirmities as the 13 the Commission found it could not yet approve. ISO-NE cautions that until the missing information is provided in the 13 cross-referenced standards, it will be impossible for the affected entities to determine what criteria they are expected to satisfy.

1009. EPSA, in contrast to ISO/RTO Council and ISO-NE, expresses its concern with the Commission's proposal not to act on the 13 fill-in-the-blank standards. EPSA considers the fill-in-the-blank standards vitally important to reliability and competitive markets and worries that progress may be lost while the regions endeavor to file the additional required information.

ii. Commission Determination

1010. The Commission will adopt the NOPR proposal and retain the same disposition of the MOD Reliability Standards that it proposed there. We confirm in this Final Rule that one out of 23 MOD standards is approved unconditionally, nine are approved with direction for modification and 13 remain pending with direction for modification. We will discuss our rationale for this decision in the Commission Determination section for each particular Reliability Standard.

1011. We reject ISO/RTO Council and ISO-NE's request that we defer our approval of Reliability Standards from the MOD group that incorporate references to the 13 fill-in-the-blank standards. While we understand ISO/RTO Council and ISO-NE's concern about cross-referencing pending Reliability Standards, the data that is needed will be provided as described in the Common Issues section.[322] In the interim, compliance with the pending Reliability Standards should continue on a voluntary basis, and the Commission considers compliance with them a matter of good utility practice. The Commission believes, moreover, that the blanks will be filled in in a timely manner, since in this rule we require the ERO to develop a Work Plan and submit a compliance filing describing the process for collection of the information set forth in the deferred standards.

1012. In response to EPSA's concern that opportunities for discrimination and concerns about reliability remain while we await additional information, we emphasize that the

[322] See Common Issues Pertaining to Reliability Standards: Fill-in-the-Blank Standards, supra section II.E.5.

Commission has provided specific direction regarding appropriate modifications to the MOD standards here and in Order No. 890, and has required the submission of a Work Plan for completion of that work within 90 days.[323] Moreover, the OATT and OASIS transparency reforms adopted in Order No. 890 will ensure that opportunities for discrimination will be minimized while NERC completes work on the MOD Reliability Standards.

b. MOD Standards Related to ATC, TTC, CBM and TRM

i. OATT Reform and the MOD Standards

1013. As pointed out in the NOPR, the Commission has been considering ATC, TTC, CBM and TRM calculation issues in Docket Nos. RM05-17-000 and RM05-25-000, and addressed them in Order No. 890. In order to maintain a consistent approach with regard to ATC issues, we confirm here the determinations made in Order No. 890. Each such determination is addressed below.

1014. In Order No. 890, the Commission addressed the potential for undue discrimination by requiring industry-wide consistency and transparency of all components of ATC calculation methodology and certain definitions, data and modeling assumptions. The Commission also indicated there that the lack of consistent, industry-wide ATC calculation standards poses a threat to the reliable operation of the Bulk-Power System, particularly with respect to the inability of one transmission provider to know with certainty its neighbors' system conditions affecting its own ATC values. As a result of this reliability component, the Commission asserted that the proposed ATC reforms are also supported by FPA section 215, through which the Commission has the authority to direct the ERO to submit a Reliability Standard that the Commission considers appropriate to implement FPA section 215.[324]

1015. In Order No. 890, the Commission directed public utilities, working through NERC and NAESB, to develop Reliability Standards and business practices to improve the consistency and transparency of ATC calculations. The Commission required public utilities, working through NERC, to modify the ATC-related Reliability Standards within 270 days of publication of Order No. 890 in the Federal Register. The Commission also directed public utilities to work through NAESB to develop business practices that complement NERC's new Reliability Standards within 360 days of publication of Order

[323] OATT Reform Final Rule, Order No. 890, issued February 15, 2007.

[324] FPA section 215(d)(5).

No. 890 in the Federal Register. Finally, the Commission directed NERC and NAESB to file a joint status report on standards and business practices development, and a Work Plan for completion of this task, within 90 days of publication of Order No. 890 in the Federal Register.

1016. The electric utility industry has also acknowledged this problem and has taken steps to address the lack of consistency and transparency in the way ATC is calculated. NERC formed a Long-Term Available Flowgate Capacity Task Force to review NERC's standards on ATC, which issued a final report in 2005.[325] Based on the recommendations in the NERC Report, NERC has begun two Standards Authorization Request proceedings to revise the standards on ATC.[326] NAESB has also begun a proceeding to develop business practice standards to enhance the processing of transmission service requests that affect ATC calculation. Following the issuance of the OATT Reform NOPR on May 19, 2006, and the Reliability Standards NOPR on October 19, 2006, NERC accelerated development of these standards in accordance with the guidelines provided in these NOPRs. NERC and NAESB representatives participated in the Commission's Technical Conference held on October 12, 2006, and informed the Commission on the status of Reliability Standards development.[327] NERC posted the Draft Standard MOD-

[325] The NERC Report made recommendations for greater consistency and greater clarity in the calculation of ATC/AFC. The task force also recommended greater communication and coordination of ATC/AFC information to ensure that neighboring entities exchange relevant information. See NERC, Long-Term AFC/ATC Task Force Final Report (2005) (NERC Report) at 2, available at: ftp://www.nerc.com/pub/sys/all_updl/mc/ltatf/LTATF_Final_Report_Revised.pdf.

[326] The first SAR proceeding proposes changes to the existing standards on ATC to, among other things, further establish consistency in the calculation of ATC and to increase the clarity of each transmission provider's ATC calculation methodology. The second SAR proceeding proposes certain changes to NERC's existing CBM and TRM standards and calls for greater regional consistency and transparency in how CBM and TRM are treated in transmission providers' ATC calculations.

[327] Technical Conference regarding Preventing Undue Discrimination and Preference in Transmission Service under RM05-25 et al. (October 12, 2006).

001-1, proposing ATC/TTC/AFC (Available Flowgate Capability) revisions, on its website on February 15, 2007.[328]

(a) Comments

1017. EPSA commends the Commission for recognizing the direct connection between the MOD group of Reliability Standards and the initiative to reform Order No. 888 to address existing opportunities to discriminate against competitive power suppliers in access to the transmission system. TAPS and EPSA note that in both the OATT Reform NOPR and the Reliability Standards NOPR, the Commission has articulated serious concerns about the lack of clarity, transparency and uniformity in the critical calculations pertaining to one of the most fundamental aspects of the wholesale bulk power transmission system, and urge the Commission to make these calculations transparent, consistent, and better yet, regional. TAPS agrees with Staff's concerns raised in the NOPR about ATC, TTC, CBM and TRM standards. Constellation particularly supports the proposed changes to MOD-001-0, MOD-004-0, MOD-006-0 and MOD-007-0 because these Reliability Standards, as modified, will provide more information to users regarding ATC, TTC, existing transmission commitments (ETC), AFC, CBM and TRM, and that information will begin the process of providing consistent standards for their calculation.

1018. Constellation agrees with EPSA and cautions that it will take time for NERC to develop, and for the Commission to definitively approve, ATC-related standards. Constellation therefore proposes that the Commission should, upon issuance of a Final Rule, require transmission providers to post the information that the Commission directs regarding these values, even if work toward more consistency is not yet complete. Constellation believes that this will aid in ensuring that users request and receive more reliable transmission service on a nondiscriminatory basis.

1019. Contrary to the majority of commenters that support Commission action regarding ATC issues, MISO states that a Reliability Standard is not the place to address perceived comparability issues. MISO states that NERC is responsible for Reliability Standards, but not for tariffs and business practices that deal with market and equity issues.

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[328] That posting preceded by one day the issuance of Order No. 890. Therefore, the posted draft Standard MOD-001-1 does not reflect the requirements of Order No. 890, but rather is guided by the NOPR issued in the OATT Reform and Reliability Standards proceedings.

(b) Commission Determination

1020. We agree with the many commenters that recognize the direct connection between the MOD group of Reliability Standards and available transfer capability methodologies addressed in Order No. 890, in which we developed policies to lessen, if not fully eliminate, opportunities to discriminate against competitive power suppliers in access to the transmission system.

1021. We recognize the concerns raised by EPSA and Constellation that opportunities for discrimination and related reliability concerns may remain during the interim Reliability Standards modification process, in part because of the discretion that transmission service providers will retain in calculating ATC values. We point out, however, that all transmission providers are required to file a modified Attachment C to their OATTs detailing their ATC calculation methodologies in advance of the development of the new Reliability Standards. All transmission providers are required to comply with their OATTs, and are subject to the filing of a complaint or Commission-initiated enforcement action if discrimination occurs. Regarding Constellation's recommendation that the Commission act in advance, and require transmission service providers to post the information that the Commission directs regarding ATC values, even if work toward more consistency is not yet complete, we clarify that we will require transmission service providers to comply with existing ATC-related posting obligations on OASIS as supplemented by Order No. 890. These requirements are not subject to standardization by the ERO, and will be effective in accordance with the timeline stated in Order No. 890.

1022. We disagree with MISO's contention that the Reliability Standards are an inappropriate venue for addressing ATC comparability issues. ATC raises both comparability and reliability issues, and it would be irresponsible to take action under FPA section 206 to require consistency in ATC calculations without considering the reliability impact of those decisions. Therefore, the Commission in Order No. 890 provided direction to public utilities, working through NERC and NAESB, regarding development of the ATC-related Reliability Standards and business practices, and we repeat that direction here.

c. Documentation of Total Transfer Capability and Available Transfer Capability Calculation Methodologies (MOD-001-0)

1023. The purpose of MOD-001-0 is to promote the consistent and uniform application of transfer capability calculations among transmission system users. The Reliability Standard requires each regional reliability organization to develop a regional TTC and ATC methodology in conjunction with its members and to post the most recent version of its TTC and ATC methodologies on a website accessible by NERC, the regional reliability organization, and transmission users.

1024. In the NOPR, the Commission identified MOD-001-0 as a fill-in-the-blank standard that requires each regional reliability organization to develop its respective methods for determining TTC and ATC and to make those methodologies available to others for review. The NOPR stated that the Commission would not propose to approve or remand MOD-001-0 until the ERO submits additional information.

1025. Although the Commission did not propose any action with regard to MOD-001-0, it addressed a number of concerns regarding the Reliability Standard, consistent with those proposed in the OATT Reform NOPR. The Commission proposed that this standard should: (1) at a minimum, provide a framework for ATC, TTC and ETC calculation; (2) require disclosure of algorithms and processes used in ATC calculation; (3) identify a detailed list of information to be exchanged among transmission providers for the purposes of ATC modeling; (4) include requirements that the assumptions used in ATC and AFC calculations be consistent with those used for planning expansion or operation of the Bulk-Power System to the maximum extent practicable;[329] (5) include a requirement that applicable entities make available assumptions and contingencies underlying ATC and TTC calculations; (6) address only ATC while the TTC should be addressed under FAC-012-1; and (7) identify to whom MOD-001-0 standards apply, i.e., users, owners and operators of the Bulk-Power System.[330] We will discuss the comments and Commission conclusions for each of these modifications separately below.

i. Comments

1026. APPA agrees with the Commission that MOD-001-0 in its current form is a fill-in-the-blank standard, is not sufficient in its current form and should not be accepted for approval as a mandatory Reliability Standard until the accompanying regional procedures are submitted and approved.

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[329] NOPR at P 609.

[330] Id. at P 610. We note that our observation regarding applicable entities here also applies to MOD-002-0, MOD-003-0, MOD-004-0, MOD-005-0, MOD-008-0, MOD-009-0, MOD-011-0, MOD-013-0, MOD-014-0, MOD-015-0, MOD-016-0, MOD-024-0 and MOD-025-0.

ii. Commission Determination

1027. The Commission adopts the NOPR proposal not to approve or remand MOD-001-0 until the ERO submits additional information. Consistent with Order No. 890, and comments received in response to the NOPR, the Commission directs the ERO to consider modifications of MOD-001-0 through the Reliability Standards development process as discussed below.

iii. Provide a framework for ATC, TTC and ETC calculation

(a) Comments

1028. APPA supports the Commission's proposal that NERC modify MOD-001-0 to, at a minimum, provide a framework for ATC, TTC and ETC calculation.

(b) Commission Determination

1029. We continue to believe that MOD-001-0 should, at a minimum, provide a framework for ATC, TTC and ETC calculations. This framework should consider industry-wide consistency of all ATC components and certain data inputs and exchange, modeling assumptions, calculation frequency, and coordination of data relevant for the calculation of ATC. Consistent with Order No. 890, we do not require a single computational process for calculating ATC for several reasons. First, it is not our intent to require transmission providers to incur the expense of developing and adopting a new one-size-fits-all software package to calculate ATC without proven benefits. More importantly, we find that the potential for discrimination and decline in reliability level does not lie primarily in the choice of an ATC calculation methodology, but rather in the consistent application of its components, and input and exchange data, along with modeling assumptions. Consistent and transparent ATC calculation will provide equivalent results between regions and will therefore prevent transmission service providers from overselling transfer capability that can stress conditions on their own and adjacent systems, and jeopardize reliability. In addition, we are especially concerned with the lack of data exchange between neighboring transmission service providers, which is a prerequisite for accurate calculation of ATC.

1030. The Commission understands that the ERO currently is developing three ATC calculation methodologies (contract or rating path ATC, network ATC, and network

AFC).[331] If all of the ATC components, and certain data inputs and assumptions are consistent, the three ATC calculation methodologies will produce predictable and sufficiently accurate, consistent, equivalent and replicable results. It is therefore not necessary to require a single industry-wide ATC calculation methodology.

1031. In addition, consistent with Order No. 890, we note that there is neither a definition of AFC/TFC (Total Flowgate Capability) in the ERO's glossary nor an existing Reliability Standard that discusses AFC. Consistent with our approach to achieving consistency and transparency, we direct the ERO to develop AFC/TFC definitions and requirements used to identify a particular set of transmission facilities as flowgates. We extend the same requirements for industry-wide consistency of all AFC components and certain data inputs and exchange, modeling assumptions, calculation frequency, and coordination of data relevant for the calculation of AFC as we stated above for ATC. However, we remind transmission providers that our regulations require the posting of ATC values associated with a particular path, not AFC values associated with a flowgate. Accordingly, transmission providers using an AFC methodology must convert flowgate (AFC) values into path (ATC) values for OASIS posting. In order to display consistent posting of ATC and TTC values on OASIS, we direct the ERO to develop a Requirement in the Reliability Standard for conversion of AFC into ATC values for use by transmission providers that currently apply flowgate methodology.

1032. We underscore Order No. 890's objective of greater consistency in ETC calculations. The Commission directs the ERO to develop a consistent approach for determining the amount of transfer capability a transmission provider may set aside for its native load and other committed uses. We expect that the ERO will address ETC through the MOD-001-0 Reliability Standard rather than through a separate Reliability Standard. By using MOD-001-0, the ETC calculation principles can be adjusted to apply

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[331] October 12, 2006 Technical Conference regarding Preventing Undue Discrimination and Preference in Transmission Service under RM05-25 et al. These three methodologies are different computational processes to determine a transmission system's ATC. The first, contract path, examines TTC for every A-to-B path on the system in concert with all others, reduces ATC by path for ETC, TRM and CBM, as appropriate, and produces ATC for each path. The second method, network ATC, uses a simulator to look not at each path, but at each transmission element (line, substation, etc.) and run first contingency simulations to establish ATC on a network basis, rather than a path basis. The third method, network AFC, uses a simulator to examine critical flowgates over a wider area, then requires a second step to convert AFC values to particular path ATC values.

to each of the three ATC methodologies being developed by the ERO. In order to provide specific direction to public utilities and the ERO, we determine that ETC should be defined to include committed uses of the transmission system, including: (1) native load commitments (including network service); (2) grandfathered transmission rights; (3) firm and non-firm point-to-point reservations; (4) rollover rights associated with long-term firm service and (5) other uses identified through the ERO process. ETC should not be used to set aside transfer capability for any type of planning or contingency reserve; these are to be addressed through CBM and TRM.[332] In addition, in the short-term ATC calculation, all reserved but unused transfer capability (non-scheduled) must be released as non-firm ATC.

1033. We reiterate the finding in Order No. 890 that including all requests for transmission service in ETC is likely to overstate usage of the system and understate ATC. Accordingly, we find that reservations that have the same point of receipt (POR) (generator) but different point of delivery (POD) (load), for the same time frame, should not be modeled in the ETC calculation simultaneously if their combined reserved transmission capacity exceeds the generator's nameplate capacity at a POR. This will prevent unrealistic use of transmission capacity associated with power output from a generator identified as a POR. One approach that could be used is examining historical patterns of actual reservation use during a particular season, month, or time of day.

1034. In summary, we direct the ERO to modify MOD-001-0 to provide a framework for ATC, TTC and ETC calculation that, consistent with the discussion above: (1) requires industry-wide consistency of all ATC components and certain data inputs and exchange, modeling assumptions, calculation frequency, and coordination of data relevant for the calculation of ATC; (2) provides predictable and sufficiently accurate, consistent, equivalent, and replicable ATC calculations regardless of the methodology used by the region; (3) provides the definition of AFC and method for its conversion to ATC; (4) lays out clear instructions on how ETC should be defined and (5) identifies to whom MOD-001-0 Reliability Standards apply, i.e., users, owners and operators of the Bulk-Power System.

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[332] TRM also includes such things as loop flow and parallel path flow.

iv. Require disclosure of algorithms and processes used in ATC calculation

(a) Comments

1035. APPA supports the Commission's proposal that NERC modify MOD-001-0 to require documentation including mathematical algorithms, process flow diagrams, data inputs and identification of flowgates.

(b) Commission Determination

1036. The Commission adopts the proposal from the NOPR to direct the ERO to modify Reliability Standard MOD-001-0 to require disclosure of the algorithms and processes used in ATC calculation. In addition, consistent with Order No. 890, the Commission believes that further clarification is necessary regarding the ATC calculation algorithm for firm and non-firm ATC.[333] Currently, the ERO has no specifications for calculating non-firm ATC. We find that the same potential for discrimination exists for non-firm transmission service as for firm service, and greater uniformity in both firm and non-firm ATC calculations will substantially reduce the remaining potential for undue discrimination. Therefore, we direct the ERO to modify Reliability Standard MOD-001-0 to require disclosure of the algorithms and processes used in ATC calculation, and also to implement the following principles for firm and non-firm ATC calculations: (1) for firm ATC calculations, the transmission provider shall account only for firm commitments and (2) for non-firm ATC calculations, the transmission provider shall account for both firm and non-firm commitments, postbacks of redirected service, unscheduled service and counterflows.

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[333] The NERC ATC definition does not differentiate firm and non-firm ATC from the following high level generic ATC definition: A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. It is defined as Total Transfer Capability less existing transmission commitments (including retail customer service), less a Capacity Benefit Margin, less a Transmission Reliability Margin. .

v. **Identify a detailed list of information to be exchanged among transmission providers for the purposes of ATC modeling**

(a) **Comments**

1037. APPA supports the Commission's proposal that NERC modify MOD-001-0 to require applicable entities to identify a detailed list of information to be shared.

(b) **Commission Determination**

1038. The Commission adopts the NOPR proposal and reiterates the requirement in Order No. 890 that the ERO must revise the MOD Reliability Standards to require the exchange of data and coordination among transmission providers. We direct the ERO to modify MOD-001-0 to ensure that the following data, at a minimum, be exchanged among transmission providers for the purposes of ATC modeling: (1) load levels; (2) transmission planned and contingency outages; (3) generation planned and contingency outages; (4) base generation dispatch; (5) existing transmission reservations, including counterflows; (6) ATC recalculation frequency and times and (7) source/sink modeling identification.[334] The Commission concludes that the exchange of such data is necessary to support the reforms requiring consistency in the determination of ATC adopted in this Final Rule. As explained above, transmission providers are required to coordinate the calculation of TTC/TFC and ATC/AFC with others, and this requires a standard means of exchanging data.

vi. **Include requirements that the assumptions used in ATC and AFC calculations should be consistent, to the maximum extent practicable, with those used for planning the expansion or operation of the Bulk-Power System**

(a) **Commission Determination**

1039. The Commission adopts the NOPR's proposal to require transmission providers to use data and modeling assumptions for short- and long-term ATC calculations that are consistent with those used for the planning of operations and system expansion, to the maximum extent practicable. This includes, for example: (1) load levels; (2) generation dispatch; (3) transmission and generation facilities maintenance schedules;

[334] NOPR at P 169.

(4) contingency outages; (5) topology; (6) transmission reservations; (7) assumptions regarding transmission and generation facility additions and retirements and (8) counterflows, which must be the same in the models used in the transmission operational and planning studies performed for the transmission providers' native load. We find that requiring consistency in the data and modeling assumptions used for ATC calculation will remedy the potential for undue discrimination by eliminating discretion and ensuring comparability in the manner in which a transmission provider operates and plans its system to serve native load, and the manner in which it calculates ATC for service to third parties.

1040. We clarify that we require consistent use of assumptions underlying operational planning for short-term ATC and expansion planning for long-term ATC calculation. We also clarify that there must be a consistent basis for or approach to determining load levels in each of these sets of calculations. For example, one approach may be for transmission providers to calculate load levels using an on- and off-peak model for each month when evaluating yearly service requests and calculating yearly ATC. The same (peak- and off-peak) or alternative approaches may be used for monthly, weekly, daily and hourly ATC calculations. Regardless of the ultimate choice, it is imperative that all transmission providers use the same approach to modeling load levels to eliminate undue discrimination and enable the meaningful exchange of data among transmission providers. Accordingly, we direct the ERO to develop consistent requirements for modeling load levels in MOD-001-0.

1041. With respect to modeling of generation dispatch, we direct the ERO to develop requirements in MOD-001-0 specifying how transmission providers should determine which generators should be modeled in service, including guidance on how independent generation should be considered. Accordingly, we direct the ERO to revise Reliability Standard MOD-001-0 by specifying that base generation dispatch will model: (1) all designated network resources and other resources that are committed to or have the legal obligation to run, as they are expected to run and (2) all uncommitted resources that are deliverable within the control area, economically dispatched as necessary to meet balancing requirements.

1042. Regarding transmission reservations modeling, we direct the ERO to develop requirements in Reliability Standard MOD-001-0 that specify: (1) a consistent approach on how to simulate reservations from points of receipt to points of delivery when sources and sinks are unknown and (2) how to model existing reservations.

1043. Consistent with Order No. 890, the Commission directs the ERO to modify Reliability Standard MOD-001-0 to require ATC to be updated by all transmission providers on a consistent time interval and in a manner that closely reflects the actual topology of the system, e.g., generation and transmission outages, load forecasts, interchange schedules, transmission reservations, facility ratings and other necessary data. This process must also consider whether ATC should be calculated more frequently for constrained facilities.

1044. In conclusion, we direct the ERO to modify MOD-001-0 to require that: (1) assumptions used for short-term ATC calculations be consistent with those used for operation planning to the maximum extent practicable; (2) assumptions used for long-term ATC calculations be consistent with those used for system planning to the maximum extent practicable and (3) ATC be updated by all transmission providers on a consistent time interval.

vii. Include a Requirement That Applicable Entities Make Available Assumptions and Contingencies Underlying ATC and TTC Calculations

(a) Comments

1045. APPA supports the Commission's proposal that NERC modify MOD-001-0 to include a requirement that applicable entities make available a comprehensive list of assumptions and contingencies underlying ATC and TTC calculations.

(b) Commission Determination

1046. We adopt the NOPR's proposal that this Reliability Standard should include a requirement that applicable entities make available a comprehensive list of assumptions and contingencies underlying ATC/AFC and TTC/TFC calculations. While we require the submission of contingency files under MOD-010-0, here we only direct the ERO to consider development of a requirement that the transmission service provider declare what type of contingencies it uses for specific calculations of ATC/AFC and TTC/TFC, and release the contingency files upon request if not submitted with the data filed with the ERO in compliance with MOD-010-0.

1047. In order to increase the transparency of ATC calculations, we adopt the NOPR's proposal and direct the ERO to develop in MOD-001-0 a requirement that each transmission service provider provide on OASIS its OATT Attachment C, in which Order No. 890 requires transmission providers to include a detailed description of the specific mathematical algorithm the transmission provider uses to calculate both firm and non-firm ATC for various time frames such as: (1) the scheduling horizon (same day and real-time), (2) operating horizon (day ahead and pre-schedule) and (3) planning horizon (beyond the operating horizon). In addition, a transmission provider must include a process flow diagram that describes the various steps that it takes in performing the ATC calculation.

viii. Address only ATC while TTC should be addressed under FAC-012-1

(a) Comments

1048. APPA concurs with the NOPR's proposal that TTC should be standardized under FAC-012-1, and that there appears to be little or no distinction between the definitions for TTC (MOD-001-0) and TC (FAC-012-1). APPA anticipates that this distinction will either be clarified or eliminated through ongoing Reliability Standards development activity.

1049. Conversely, MidAmerican notes that the transfer capability covered by FAC-012-1 may not relate to the TTC that is the subject of the MOD-001-0 standard. MidAmerican opines that the purpose of the FAC-012-1 standard is to ensure that each reliability coordinator and planning authority documents the methodology used to develop inter- and intra-regional transfer capabilities used in the reliable planning and operation of the Bulk-Electric System. MidAmerican further details that transfer capabilities that are covered by FAC-012-1 could be used by a reliability coordinator to operate the system in a temporary situation or by the planning authority as the basis for a sensitivity case. It adds that in neither of these cases would these transfer capabilities necessarily be included in calculations for ATC that would be used for offering transmission capacity for sale.

(b) Commission Determination

1050. We adopt the NOPR proposal and require that TTC be addressed under the Reliability Standard that deals with transfer capability such as FAC-012-1, rather than MOD-001-0. The FAC series of standards contain the Reliability Standards that form the technical and procedural basis for calculating transfer capabilities. FAC-008-1 provides the basis for determining the thermal ratings of facilities while FAC-009-1 provides the basis for communicating those ratings. FAC-010-1 and FAC-011-1 provide the system operating limits methodologies for the planning and operational horizon respectively and FAC-014 provides for the communication of those ratings.[335]

1051. The Commission directs the ERO, through the Reliability Standards development process, to modify FAC-012-1 and any other appropriate Reliability Standards to assure

[335] FAC-010, FAC-011, and FAC-014 are addressed in Docket No. RM07-03 because they were submitted later than the original 107 Reliability Standards and we did not have sufficient time to allow appropriate review and comment.

consistency in the determination of TTC/TFC for services provided under the pro forma OATT, and requires that those processes be the same as those used in operation and planning for native load and reliability assessment studies. Changes to the process of calculating TTC are appropriate if implementation is coordinated with revisions to the other applicable operating or planning standards. We acknowledge that reliability regions have historically calculated transfer capability using different approaches, and we agree that regional differences should be respected.[336] However, as already discussed above regarding ATC, TTC requirements will be determined in the ERO Reliability Standards development process, and any request for a regional difference from the Reliability Standards must take place through the ERO process.

1052. We disagree with MidAmerican's opinion that transfer capabilities that are addressed by FAC-012-1 are necessarily different from TTC used for ATC calculation. The NERC glossary defines transfer capability (TC)[337] as essentially identical to TTC.[338] We believe that modeling principles for simulating power transfers and determination of transfer capabilities should be the subject of a single standard. Those principles should be the same regardless of whether transfer capability is used for the purpose of operations, planning or offering for sale. By modeling principles we refer to the way transfers are simulated and the type of analysis that should be performed, such as steady-state, dynamic stability or voltage stability. We are certain that consistent calculation of transfer capabilities will prevent over- and under-estimation of the total transfer capability available for sale. We agree with APPA that this distinction should either be clarified or eliminated through the ongoing Reliability Standards development process,

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[336] For example, WECC has a documented open process for establishing TTC for the Western Interconnection.

[337] Transfer Capability is defined in the NERC glossary as "[t]he measure of the ability of interconnected electric systems to move or transfer power in a reliable manner from one area to another over all transmission lines (or paths) between those areas under specified system conditions. The units of transfer capability are in terms of electric power, generally expressed in megawatts (MW). The transfer capability from 'Area A' to 'Area B' is not generally equal to the transfer capability from 'Area B' to 'Area A.'" NERC Glossary at 18.

[338] Total Transfer Capability is defined in the NERC glossary as "[t]he amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions." Id..

and therefore direct the ERO to modify MOD-001-0 to address TTC under transfer capability-related standards such as the FAC group of Reliability Standards.

ix. Identify the entities to whom the MOD Standards apply

(a) Comments

1053. APPA agrees in part with the Commission's conclusion that "NERC should identify the applicable entities in terms of users, owners and operators of the Bulk-Power Systems."[339] APPA, however, is concerned that this approach may confuse rather than clarify compliance responsibilities. According to APPA, a regional organization in conjunction with entities that plan, own, operate (and use) transmission facilities within each region must be involved in the development of any regional TTC and ATC methodology. In this context, APPA views the "regional reliability organization" as the technical arm of the reliability region, made up of the various committees whose members are users, owners and operators of the Bulk-Power System, along with support from the regional reliability organization staff. Further, APPA notes that ultimately, it is these core users, owners and operators of the Bulk-Power System that are responsible for the development of and adherence to the ATC methodology, and that the regional reliability organization, as an organization, is responsible for ensuring that the methodology is developed (under R1) and publicly posted (under R2).

1054. In addition, APPA states that under the statutory framework established in FPA section 215, as interpreted by the Commission in Order No. 672, it is clear that the compliance monitor within each region is the Regional Entity, and the Regional Entity is not a user, owner or operator of the Bulk-Power System. APPA notes that while regional delegation agreements may be used to impose certain reliability compliance functions upon Regional Entities and their affiliates, no Regional Entity should be charged with enforcing compliance against itself. Ultimately, APPA is concerned that the quality of regional modeling and technical assessments will be diminished if the collaborative efforts used for the past 50 years of interconnected operations are displaced due to pressures to identify a single entity or class of entities with direct compliance responsibilities for regional modeling standards. APPA states that identifying all users, owners and operators as responsible entities does not answer the question either. APPA expresses its intention that it will work with NERC and with other stakeholders to ensure that this industry-based expertise is maintained and enhanced, while ensuring that responsible entities are identified in this and other NERC standards.

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[339] NOPR at P 610.

(b) Commission Determination

1055. APPA is suggesting that respective regional organizations, their technical staff, and committees of users, owners and operators of the Bulk-Power System be charged with developing the methodologies. We disagree. These Reliability Standards should be developed through the Commission-approved Reliability Standards development process which will identify the entities that should implement the Reliability Standards, the Requirements necessary to achieve the goals identified in Order No. 890, and the Measures necessary to monitor compliance.

1056. The Commission agrees with APPA that the collaborative efforts and knowledge developed over decades of interconnected operation should not be wasted. We do not believe that will happen through the Reliability Standards development process and that all of the applicable entities will have significant roles to play in achieving the goal the Commission has set out in Order No. 890. Therefore, we adopt the proposal in the NOPR and direct the ERO to modify MOD-001-0 to reflect the users, owners and operators to which the Reliability Standard will apply.

x. Summary of Commission Determination

1057. Accordingly, the Commission neither accepts nor remands MOD-001-0 until the ERO submits additional information. Although the Commission does not propose any action with regard to MOD-001-0, we address above a number of concerns regarding the Reliability Standard, consistent with those set forth in Order No. 890. We direct the ERO to develop modifications to the Reliability Standard through the Reliability Standards development process that: (1) provide a framework for ATC, TTC and ETC calculation, developing industry-wide consistency of all ATC components; (2) require disclosure of algorithms, for both firm and non-firm ATC and processes used in the ATC calculation; (3) identify a detailed list of information to be exchanged among transmission providers for the purposes of ATC modeling; (4) include a requirement that the assumptions used in ATC and AFC calculations should be consistent with those used for planning the expansion or operation of the Bulk-Power System to the maximum extent practicable; (5) include a requirement that ATC be updated by all transmission providers on a consistent time interval; (6) include a requirement that applicable entities make available assumptions and contingencies underlying ATC and TTC calculations; (7) address only ATC/AFC while TTC/TFC should be addressed under transfer capability standards such as FAC-012-1 and (8) identify the applicable entities in terms of users, owners and operators of the Bulk-Power System.

d. Review of Transmission Service Provider Total Transfer Capability and Available Transfer Capability Calculations and Results (MOD-002-0)

1058. MOD-002-0 concerns the review of transmission service providers' compliance with the regional methodologies for calculating TTC and ATC. It requires that the regional reliability organization: (1) develop and implement a procedure to periodically review and ensure that the TTC and ATC calculations and resulting values developed by transmission service providers comply with the regional TTC and ATC methodology and applicable regional criteria; (2) document the results of its periodic review and (3) provide the results of its most current reviews to NERC upon request.

1059. In the NOPR, the Commission identified MOD-002-0 as a fill-in-the-blank standard that requires each regional reliability organization to develop and implement a procedure to periodically review and ensure that a transmission service provider's TTC and ATC calculations comply with regional TTC and ATC methodologies and criteria. The NOPR stated that the Commission would not propose to approve or remand MOD-002-0 until the ERO submits additional information.

i. Comments

1060. APPA agrees that MOD-002-0 is a fill-in-the-blank standard. It is not sufficient in its current form and should not be approved as a mandatory Reliability Standard until the accompanying regional procedures are submitted and approved.

ii. Commission Determination

1061. The Commission adopts the NOPR proposal not to approve or remand MOD-002-0 until the ERO submits additional information. Because the regional procedures have not been submitted to the Commission, it is not possible to determine at this time whether MOD-002-0 satisfies the statutory requirement that a proposed Reliability Standard be "just, reasonable, not unduly discriminatory or preferential, and in the public interest." Accordingly, the Commission neither approves nor remands this Reliability Standard until the regional procedures are submitted. In the interim, compliance with MOD-002-0 should continue on a voluntary basis, and the Commission considers compliance with the Reliability Standard to be a matter of good utility practice.

e. Regional Procedure for Input on Total Transfer Capability and Available Transfer Capability Methodologies and Values (MOD-003-0)

1062. MOD-003-0 requires each regional reliability organization to: (1) develop and document a procedure on how a transmission user can present its concerns or questions regarding TTC and ATC calculations including the TTC and ATC values, and how these concerns will be addressed and (2) make its procedure for receiving and addressing these concerns available to other regional reliability organizations, NERC and transmission users on its website.

1063. In the NOPR, the Commission identified MOD-003-0 as a fill-in-the-blank standard that requires each regional reliability organization to develop and document a procedure on how a transmission user can present its concerns regarding the TTC and ATC methodologies of a transmission service provider. The NOPR stated that the Commission would not propose to approve or remand MOD-003-0 until the ERO submits additional information.

i. Comments

1064. APPA agrees that MOD-003-0 is a fill-in-the-blank standard. It notes that it is not sufficient in its current form and should not be approved as a mandatory Reliability Standard until the accompanying regional procedures are submitted and approved. In addition, APPA hopes that if NERC develops the MOD-001-0 Reliability Standard properly, it will include a reporting procedure for addressing shortcomings in information for all transmission customers (LSE, generator owner and purchasing-selling entity) in the MOD-001-0 Standard. APPA argues that, as a result, MOD-003-0 may be redundant and should be eliminated.

ii. Commission Determination

1065. The Commission adopts the NOPR proposal not to approve or remand MOD-003-0 until the ERO submits additional information. Because the regional procedures have not been submitted to the Commission, it is not possible to determine at this time whether MOD-003-0 satisfies the statutory requirement that a proposed Reliability Standard be "just, reasonable, not unduly discriminatory or preferential, and in the public interest." Accordingly, the Commission neither accepts nor remands this Reliability Standard until the regional procedures are submitted. In the interim, compliance with MOD-003-0 should continue on a voluntary basis, and the Commission considers compliance with the Reliability Standard to be a matter of good utility practice.

1066. We direct the ERO to consider APPA's suggestion that MOD-003-0 may be redundant and should be eliminated if the ERO develops a modification to the MOD-001-0 Reliability Standard through the Reliability Standards development process that includes reporting requirements.

f. Documentation of Regional Reliability Organization Capacity Benefit Margin Methodologies (MOD-004-0)

1067. MOD-004-0 requires each regional reliability organization to: (1) develop and document a regional CBM[340] methodology in conjunction with its members and (2) post the most recent version of its CBM methodology on a website accessible by NERC, regional reliability organizations and transmission users.

1068. In the NOPR, the Commission identified MOD-004-0 as a fill-in-the-blank standard that requires each regional reliability organization to develop and document a regional CBM methodology. The NOPR stated that because the regional CBM methodologies had not been submitted, the Commission would not propose to approve or remand MOD-004-0 until the ERO submits the additional information.

1069. Although not proposing any action, the Commission nonetheless indicated that MOD-004-0 could be improved by: (1) providing more specific requirements on how CBM should be determined and allocated to interfaces and (2) including a provision ensuring that CBM, TRM and ETC cannot be used for the same purpose, such as the loss of an identical generation unit. Further, the Commission expressed concern that the Reliability Standard may unduly impact competition because of the lack of consistent criteria and clarity with regard to the entity on whose behalf CBM has been set aside. This lack of consistent criteria has the potential to result in the transmission provider's setting aside capacity that it might not otherwise need to set aside, thus increasing costs for native load customers and blocking third party uses of the transmission system.

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[340] The NERC glossary defines "capacity benefit margin" or "CBM" as the amount of firm transmission transfer capability preserved by a transmission provider for load serving entities whose loads are located on the transmission service provider's system, to enable access by the load serving entity to generation from interconnected systems to meet generation reliability requirements. NERC Glossary at 2.

i. Comments

1070. APPA agrees with the Commission that MOD-004-0 should not be approved as a mandatory Reliability Standard until the relevant regional procedures are submitted and approved.[341]

1071. FirstEnergy states that transmission capacity margins such as CBM and TRM are vitally important to the reliability of the system, and any methodology that would unduly limit these margins could create a danger of limiting transmission capacity over interconnected facilities that would limit the ability of balancing authorities and others to obtain generation reserves needed from the grid during contingency events. In contrast, TAPS questions how TRM or, especially, CBM, can be viewed as Reliability Standards if they are optional for the transmission provider.

1072. MidAmerican supports greater uniformity of CBM definitions and calculations and states that the revised standard and/or new standards should support transparency and uniformity by encouraging increased availability of information and consistent data input and modeling assumptions. EEI emphasizes that additional data and information-sharing requirements would improve the transparency of various calculations and assumptions related to CBM, including this standard and the other CBM-related standards. EEI believes that, similar to the peer review processes of the planning studies carried out under the TPL standards, industry participants are best suited to developing the totality of assumptions, system conditions and other input variables that support the calculations.

1073. EEI notes that, with respect to the Commission's particular concern about criteria in determining resources and loads used in the CBM methodology, NERC's "ATC Definitions and Determination"[342] document clearly delineates the purpose and intent of the calculation of CBM and TRM. EEI states that CBM is intended to provide generation reliability, and TRM is intended to provide transmission reliability. EEI believes that, to the extent capacity capable of supplying CBM is located in the vicinity of the designated facility experiencing an outage, transmission may or may not be available under the

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[341] APPA notes that it has expressed its own concerns with CBM calculations and set-asides in its August 7, 2006 Initial Comments filed in Docket No. RM05-25-000, at 31–55. APPA is hopeful these concerns can be addressed through NERC's Reliability Standards development process.

[342] NERC, Available Transfer Capability Definitions and Determination - A Framework for Determining Available Transfer Capabilities of the Interconnected Transmission Networks for a Commercially Viable Electricity Market (June 1996).

native load reservation normally used for the facility. Therefore, EEI argues, CBM may be needed on an interface where capacity is available for use as CBM, and not allowing all generation to be considered in this manner may unduly increase the generation reserve requirement within the transmission provider's system.

1074. EEI agrees with the Commission's concern about double-counting TRM for those transmission providers who do not opt to use CBM. However, EEI argues that for transmission providers who do opt to use CBM, it may be appropriate in some circumstances to use the same generation unit outage to determine the impact on both generation and transmission reliability because the impacts are different. EEI cautions that artificially restricting such use is not appropriate, especially before NERC's development of TRM and CBM standards and their presentation to FERC through the Reliability Standards development process. EEI recommends that the Commission encourage transmission providers to make CBM and TRM capacity available to wholesale markets for purchase on a non-firm basis, because doing so would ensure that both CBM and TRM capacity are available to the transmission provider during system emergencies, as intended. EEI notes that at other times the transfer capability associated with TRM and CBM would be available to the market, alleviating the concern of possible double-counting. MidAmerican also supports the Commission's conclusion that double-counting would be inappropriate, although MidAmerican states that it is not aware of any cases of double-counting of margins.

1075. TAPS notes the significant potential for abuse[343] that could result from the current flexibility afforded transmission providers in the calculation of CBM and TRM, and proposes innovative approaches[344] to take CBM and (to the extent it is intended to cover transmission required for reserve sharing) TRM out of the hands of individual transmission providers, and to therefore reduce the opportunity for abuse.

ii. Commission Determination

1076. The Commission adopts the NOPR proposal not to approve or remand MOD-004-0 until the ERO submits additional information. Because the regional procedures have not been submitted to the Commission, it is not possible to determine at this time whether MOD-004-0 satisfies the statutory requirement that a proposed Reliability Standard be

[343] Documented by NERC's April 14, 2005 Long-Term AFC/ATC Task Force Final Report.

[344] TAPS refers the Commission to its August 7, 2006 comments in Docket No. RM05-25-000 at 21-24.

"just, reasonable, not unduly discriminatory or preferential, and in the public interest." Accordingly, the Commission neither accepts nor remands this Reliability Standard until the regional procedures are submitted. In the interim, compliance with MOD-004-0 should continue on a voluntary basis, and the Commission considers compliance with the Reliability Standard to be a matter of good utility practice. Consistent with Order No. 890 and comments received in response to the NOPR, the Commission directs the ERO, through the Reliability Standards development process, to modify MOD-004-0 as discussed below.

1077. We agree with FirstEnergy that CBM is important for system reliability by allowing the LSEs to meet their historical, state, RTO or regional generation reliability criteria requirement such as reserve margin, loss of load probability, loss of largest units, etc. We agree with EEI and MidAmerican that transparency of the studies supporting CBM determination will reduce the opportunity for transmission service providers to overestimate the amount of CBM and misuse transfer capability. We therefore direct the ERO to develop Requirements regarding transparency of the generation planning studies used to determine CBM values. We also clarify that CBM should only be set aside upon request of any LSE within a balancing area to meet its verifiable historical, state, RTO or regional generation reliability criteria requirement such as reserve margin, loss of load probability, loss of largest units, etc. We expect verification of the CBM values to be part of the Requirements with appropriate Measures and Levels of Non-Compliance.

1078. We continue to believe this Reliability Standard should be modified to include a provision ensuring that CBM, TRM and ETC cannot be used for the same purpose, such as loss of the identical generating unit. In order to limit misuse of transfer capability set aside as CBM, we direct the ERO to provide more specific requirements for how CBM should be determined and allocated across transmission paths or flowgates. As we stated in Order No. 890, we do not mandate a particular methodology for allocating CBM to paths or flowgates. For example, one approach could be based on the location of the outside resources or spot market hubs that a LSE has historically relied on during emergencies resulting from an energy deficiency, but we agree with EEI that flexible rules should be allowed to prevent unnecessary increase of the generation reserve requirement within the transmission provider's system. Therefore, we support flexibility, but expect that the ERO, using its Reliability Standards development process, will adequately approach these complex technical issues and propose a new version of MOD-004-0 that addresses the methods for CBM determination and allocation on paths that will reduce reliability and discrimination concerns.

1079. In response to TAPS's question asking how CBM can be viewed as a Reliability Standard if it is optional to the transmission provider, our understanding is that transmission providers that have opted not to use CBM have instead set aside transmission margin (needed to bring in outside power to meet generation reliability criteria) either through ETC or TRM. CBM is not the only way to reserve transmission capacity for a margin. However, if the Reliability Standard is not clear regarding the method of calculating transmission margins, it may cause double-counting of transmission margins and reduction of ATC. As we stated in Order No. 890, we find that clear specification of the permitted purposes for which entities may reserve CBM and TRM will virtually eliminate double-counting of TRM and CBM. Therefore, we direct the ERO to modify its standard in order to prevent setting aside transfer capability for the same purposes.

1080. We share TAPS's concern that there is a significant potential for abuse as a result of the current flexibility afforded to transmission providers in the calculation of both CBM and TRM. In response to TAPS's concern, we clarify that in accordance with the OATT Reform Final Rule and the ERO CBM definition, each LSE has the right to request CBM be set aside and use it to meet its verifiable historical, state, RTO or regional generation reliability criteria requirement such as reserve margin, loss of load probability, loss of largest units, etc. As such, the LSEs that request CBM be set aside must be identified as applicable entities with identified Requirements, including Requirements on generation studies to verify the set aside, Measures and Levels of Non-Compliance. We direct the ERO to modify the Reliability Standard accordingly.

1081. We agree with TAPS that there is a need for clearer requirements in the standard regarding to whom and how to submit a request for CBM set-aside, and what the transmission service provider should do if the sum of all CBM requirements exceeds the amount of available transfer capability. We direct the ERO to address the reliability aspects in the Reliability Standards development process and explore with NAESB whether business practices would be required.

1082. Accordingly, the Commission neither accepts nor remands MOD-004-0 until the ERO submits additional information. In the interim, compliance with MOD-004-0 should continue on a voluntary basis, and the Commission considers compliance with the Reliability Standard to be a matter of good utility practice. Although the Commission did not propose any action with regard to MOD-004-0, it addressed above a number of concerns regarding the Reliability Standard, consistent with those set forth in Order No. 890. Therefore, we direct the ERO to develop modifications to the Reliability Standard through the Reliability Standards development process to: (1) clarify that CBM shall be set aside upon request of any LSE within a balancing area to meet its verifiable historical, state, RTO or regional generation reliability criteria; (2) develop requirements regarding transparency of the generation planning studies used to determine CBM value; (3) modify the current Requirements to make clear the process for how CBM is allocated across transmission paths or flowgates; (3) modify its standard in order to prevent setting aside

CBM and TRM for the same purposes; (4) modify the standard by adding LSE as an applicable entity and (5) coordinate with NAESB business practice standards.

1083. We direct the ERO to consider APPA's suggestion that MOD-004-0 may be redundant and should be eliminated if the ERO develops a modification to the MOD-002-0 Reliability Standard that includes reporting requirements

g. Procedure for Verifying Capacity Benefit Margin Values (MOD-005-1)

1084. MOD-005-1 specifies the requirements regarding the periodic review of a transmission service provider's adherence to the regional reliability organization's CBM methodology. It requires each regional reliability organization to: (1) develop and implement a procedure to review at least annually the CBM calculations and the resulting values determined by member transmission service providers; (2) document its CBM review procedure and (3) make the results of the most current CBM review available to NERC upon request.

1085. In the NOPR, the Commission identified MOD-005-0 as a fill-in-the-blank standard that requires each regional reliability organization to develop and implement a procedure to review CBM calculations and the resulting values and to make the documentation of the results of the CBM review available to NERC and others. The NOPR stated that because the regional procedures had not been submitted, the Commission would not propose to approve or remand MOD-005-0 until the ERO submits the additional information.

i. Comments

1086. APPA agrees that MOD-005-0 is a fill-in-the blank standard, and that in its current form, it is not sufficient and should not be accepted for approval as a mandatory Reliability Standard until the necessary regional procedures have been submitted and approved. APPA suggests that NERC modify MOD-006-0, so that MOD-004-0 and MOD-005-0 could be eliminated.

ii. Commission Determination

1087. The Commission adopts the NOPR proposal not to approve or remand MOD-005-0 until the ERO submits additional information. Because the regional procedures have not been submitted to the Commission, it is not possible to determine at this time whether MOD-005-0 satisfies the statutory requirement that a proposed Reliability Standard be "just, reasonable, not unduly discriminatory or preferential, and in the public interest." Accordingly, the Commission neither accepts nor remands this Reliability Standard until the regional procedures are submitted. In the interim, compliance with MOD-005-0 should continue on a voluntary basis, and the Commission considers compliance with the Reliability Standard to be a matter of good utility practice.

1088. As to APPA's comment on incorporating MOD-004 and MOD-005 into MOD-006, we direct the ERO to consider those comments through the Reliability Standards development process.

h. Procedure for Use of Capacity Benefit Margin Values (MOD-006-0)

1089. The purpose of MOD-006-0 is to promote the consistent and uniform use of transmission CBM calculations among transmission system users. MOD-006-0 requires that each transmission service provider document its procedure for the scheduling of energy against a CBM reservation and make the procedure available on a website accessible by the regional reliability organization, NERC and transmission users.

1090. In the NOPR, the Commission proposed to approve Reliability Standard MOD-006-0 as mandatory and enforceable. In addition, the Commission proposed to direct NERC to submit a modification to MOD-006-0 that: (1) includes a provision that will ensure that CBM and TRM are not used for the same purpose; (2) modifies Requirement R1.2 so that concurrent occurrence of generation deficiency and transmission constraints is not a required condition for CBM usage; (3) modifies Requirement R1.2 to define "generation deficiency" based on a specific energy emergency alert level and (4) expands the applicability section to include the entities that actually use CBM, such as LSEs.

1091. In addition, the Commission proposed that NERC should clarify the requirements to address when and how CBM can be used to reduce transmission provider discretion with regard to CBM usage. The Commission provided guidance expressing its belief that CBM should be used only when the LSE's local generation capacity is insufficient to meet balancing Reliability Standards, and that CBM should have a zero value in the calculation of non-firm ATC.

i. Comments

1092. APPA supports the Commission's proposal to approve MOD-006-0. Moreover, APPA agrees with the Commission's proposed directives[345] that the standard should address the use of CBM and TRM for the same purpose. However, APPA believes that

[345] NOPR at P 642.

the specificity of the Commission's proposed directives to NERC, if implemented, would undermine NERC's role as the approved ERO with the technical expertise to develop and revise standards for the Commission's subsequent review. APPA therefore suggests that the Commission in its Final Rule make clear to NERC its concerns about MOD-006-0, but then let NERC address those concerns through its Reliability Standard development process.

1093. Regarding the Commission's proposal that MOD-006-0 R1.2 be modified "so that concurrent occurrence of transmission constraints and a generation deficiency is not a requirement for CBM usage," WEPCO asserts that the Commission is misinterpreting CBM. WEPCO states that if there is no transmission constraint then there is no need to use CBM. In that case, transmission capacity exists for a LSE to import energy. If there is a transmission constraint, CBM reserves transmission capacity that the LSE can use to import energy for reliability needs.

1094. EEI points out that the explicit intention for CBM is that it be used only during conditions where there are emergency generation deficiencies. However, EEI emphasizes that the Commission's recommendation does not consider that the LSE's supply and demand balance varies season to season, over time, and with supply and demand uncertainties. EEI says that the development of CBM quantities must be carried out in a manner that sets aside transmission capability for forecasted conditions and uncertainties much like the native load reservations necessary for serving reasonably-forecasted native load. An argument may be made that during a period of time when a LSE's expected reserves are substantially greater than its targeted reserves, the need for CBM set-aside decreases. However, should the LSE foresee that this "excess" would occur substantially in the future, a reduction in CBM would not be warranted since substantial uncertainties still exist.

1095. Additionally, regarding the Commission's proposal that a LSE that "has sufficient generation resources within its balancing authority to meet the balancing Reliability Standards, should not need to preserve capacity for CBM at all," WEPCO argues that just because the balancing authority has sufficient generation does not mean that there is sufficient transmission capacity to deliver the energy to the LSE. WEPCO states that the LSE may be remote from the bulk of the balancing authority, so there may be occasions when a LSE that has sufficient generation resources within its balancing authority to meet the balancing Reliability Standards may still need to reserve capacity for CBM. In addition, EEI argues that the Commission's viewpoint does not take into account the availability of these resources unless they are under contract with the LSE to provide this service. EEI contends that the implication of this suggestion is to unduly restrict the sources of generation capacity available for CBM during times of generation shortage, which results in the LSE's being captive to local generation that is available and does not allow access to the market outside of the LSE's balancing authority. Additionally, EEI cautions that this action may require the LSE to develop contractual agreements with local generation and thus increase costs to the LSE's rate payers.

1096. Given the strong direction on CBM issues in the OATT Reform NOPR, TAPS assumes that the Commission would not be approving the Version 0 standards on these competitively crucial issues, but would continue to address them forcefully in the OATT Reform proceeding. TAPS notes that, although that is the course largely adopted by the NOPR in this proceeding, the NOPR[346] proposes to approve MOD-006-0 and MOD-007-0, with directions to improve these standards. TAPS notes that such action is inconsistent with the Commission's general approach to ATC/TTC/TRM/CBM standards in this docket and the OATT Reform NOPR. TAPS further states that, given the absence of clear access of non-transmission owner LSEs to CBM, the proposed expansion of MOD-007-0 to include such LSEs in the NOPR[347] seems bizarre.

ii. Commission Determination

1097. The Commission adopts the NOPR proposal to approve MOD-006-0 as mandatory and enforceable. Consistent with Order No. 890 and comments received in response to the NOPR, the Commission directs the ERO to modify MOD-006-0 as discussed below.

1098. Consistent with the views of many commenters, we adopt the NOPR proposal that requires a provision that will ensure that CBM and TRM are not used for the same purpose. As discussed under MOD-004-0 concerning the reservation of transfer capacity, we believe that if the Reliability Standard is not clear regarding the conditions specifying both the reservation and the use of CBM, it may cause double-counting. Such double-counting will lead to an unnecessary reduction of ATC, and create opportunities for discrimination. Therefore, we direct the ERO to modify its standard to prevent use of CBM and TRM for the same purposes. We agree with APPA that the ERO should use its Reliability Standards development process to address the double-counting problem.

1099. We adopt the NOPR's proposal and direct the ERO to modify Requirement R1.2 so that a transmission constraint is not a required condition for CBM usage. The glossary definition and the use as defined in Order No. 890 is that CBM "is intended to be used by

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[346] Id. at P 642, 648.

[347] Id. at P 647-48.

the LSE only in time of emergency generation deficiencies."[348] Therefore we direct the ERO to modify the standard in the manner proposed in the NOPR.

1100. We adopt the NOPR proposal that requires modification of Requirement R1.2 to define "generation deficiency" based on a specific energy emergency alert level. This approach will provide clarity as to when the use of CBM may be permitted. We therefore direct the ERO to modify the Reliability Standard to include a specific energy emergency alert level that will trigger CBM usage.

1101. We also reiterate the direction in Order No. 890 that CBM should have a zero value in the calculation of non-firm ATC because non-firm service may be curtailed so that CBM can be used. CBM is reserved as part of the firm transfer capability so that it is available when needed for energy emergencies. We determine that each LSE should be permitted to call for use of CBM, provided all of the other Requirements of R1.1 are met. We direct that CBM may be implemented up to the reserved value when a LSE is facing firm load curtailments.

1102. We adopt the NOPR proposal that CBM should be used only when the LSE's local generation capacity is insufficient to meet balancing Reliability Standards, with the clarification that the local generation is that generation capacity that is either owned or contracted for by the LSE. We disagree with WEPCO that just because the balancing authority has sufficient generation does not mean that there is transmission capacity to deliver the energy to the LSE. The Commission finds that such a scenario would violate existing transmission operating and transmission planning Reliability Standards. There is an explicit requirement in the transmission operating standards that generation reserves must be deliverable to load.[349] Also, there is an explicit requirement in the transmission planning standards that all firm load must be supplied under various system conditions with and without contingencies.[350] The Commission is not prescribing how these requirements should be met. There are a variety of approaches to do so, including adequate transmission capability, local or dynamic generation transfers into the area or DSM. To clarify for EEI, our proposal does not take into account the availability of these resources unless they are under contract with the LSE to provide this service. We developed our NOPR proposal on the rationale derived from the CBM concept, and

[348] See NERC Glossary at 2.

[349] TOP-002-2.

[350] TPL-002-0.

believe that if there are enough resources to meet generation reliability criteria within the balancing authority, there is no need to request CBM.

1103. We also adopt the NOPR proposal to require the applicability section to include the entities that actually use CBM, such as LSEs. The current CBM definition in the NERC glossary determines that LSEs are users of CBM. Load-serving entities determine when to use CBM, initiate CBM use and call for its end. Load-serving entities therefore have to comply with the standard requirements that specify the conditions under which CBM will be used. We direct the ERO to modify the standard accordingly.

1104. With regard to TAPS's comments concerning its assumption that the Commission would not be approving the Version 0 standards on these issues, but would continue to address them in the OATT Reform proceeding, the Commission finds that MOD-006-0 and MOD-007-0 do not establish CBM values, but rather address CBM implementation and documentation. The implementation of CBM has critical implications for the reliable operation of the Bulk-Power System and we find that these Reliability Standards should be mandatory and enforceable. The competitively significant issue is to assure that there is no double-counting of CBM and to determine the magnitude of CBM which is addressed in other Reliability Standards that the Commission has not approved or remanded.

1105. The Commission approves MOD-006-0 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification to Reliability Standard MOD-006-0 through the Reliability Standards development process that: (1) includes a provision that will ensure that CBM and TRM are not used for the same purpose; (2) provides that CBM should be used for emergency generation deficiencies; (3) modifies Requirement R1.2 to define "generation deficiency" based on a specific energy emergency alert level; (4) includes a provision that CBM should have a zero value in the calculation of non-firm ATC and (5) expands the applicability section to include the entities that actually use CBM, such as LSEs.

i. Documentation of the Use of Capacity Benefit Margin (MOD-007-0)

1106. MOD-007-0 requires transmission service providers that use CBM to report and post its use.

1107. In the NOPR, the Commission proposed to approve Reliability Standard MOD-007-0 as mandatory and enforceable. In addition, the Commission proposed to direct NERC to submit a modification to MOD-007-0 that expands the applicability section to include the entities that actually use CBM, such as LSEs.

i. Comments

1108. APPA supports the Commission's proposed approval of MOD-007-0. However, it believes that the issue of whether LSEs should be made subject to MOD-007-0 should be left to NERC in the first instance to decide. In so doing, NERC should consider expanding MOD-007-0 to cover not only LSEs, but also balancing authorities. Under NERC's Functional Model, the balancing authority is the entity that would schedule energy over transmission capacity reserved as CBM. Moreover, it is the balancing authority that would know the information necessary to report an incident during which the balancing authority had to import energy from outside the balancing authority's own area from a resource designated as operating reserves and change the net scheduled interchange with the neighboring balancing authorities to allow the energy to flow into the balancing authority's area.

ii. Commission Determination

1109. The Commission approves MOD-007-0 as mandatory and enforceable. Consistent with the comments received in response to the NOPR, the Commission directs the ERO to modify the standard as discussed below.

1110. We also adopt the NOPR's proposal to require the applicability section to include the entities that actually use CBM and report on their CBM use, such as LSEs. The current CBM definition in the NERC glossary determines when a LSE is a CBM user. The LSE determines how much CBM will be set aside, when CBM use will start and when it will end. The LSE must therefore comply with the standard requirements that require reporting and posting of CBM use. We direct the ERO to modify the standard to include the entities that actually use CBM, such as LSEs. In addition, we agree with APPA that the Reliability Standard should apply to balancing authorities and direct the ERO to include balancing authorities within the entities to which this standard is applicable.

1111. Accordingly, the Commission approves MOD-007-0 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification through its Reliability Standards development process that expands the applicability of MOD-007-0 to include the entities that actually use CBM, such as LSEs and balancing authorities.

j. Documentation and Content of Each Regional Transmission Reliability Margin Methodology (MOD-008-0)

1112. MOD-008-0 requires the development and posting of a regional methodology for TRM, which is transmission capacity that is reserved to provide reasonable assurance that the interconnected transmission network will remain secure under various system conditions. The Reliability Standard requires each regional reliability organization to: (1) develop and document a regional TRM methodology in conjunction with its members and (2) post on a website the most recent version of its TRM methodology.

1113. In the NOPR, the Commission identified MOD-008-0 as a fill-in-the-blank standard, proposing that because the regional methodologies had not been submitted, the Commission would not propose to approve or remand MOD-008-0 until the ERO submitted the additional information. The Commission expressed concern about the lack of: (1) clear requirements on how TRM should be calculated and allocated across paths and (2) consistent criteria and clarity with regard to the entity on whose behalf TRM had been set aside.

1114. The Commission requested comment in the NOPR on how TRM is currently calculated and allocated across paths, and what would be a recommended approach for the future.

i. Comments

1115. APPA agrees that MOD-008-0 is a fill-in-the-blank standard, is not sufficient as currently drafted, and should not be approved as a mandatory Reliability Standard until NERC and the regional reliability organizations and regional entities develop the necessary regional methodologies and the Commission approves them.

1116. MISO adds that there should be a consistent framework to be followed by entities in determining TRM. It states that relevant MOD standards should be revised if such a framework is not clearly delineated. However, MISO cautions that a Reliability Standard should not be used to address a perceived equity concern. MidAmerican also supports greater uniformity of TRM definitions and calculations, and proposes that a revised standard and/or new standards should encourage transparency with increased availability of information, consistent data input and certain modeling assumptions. International Transmission agrees and proposes that TRM consistency should be addressed either on a regional basis or on an Interconnection-wide basis.

1117. In response to the Commission's request for comments on the current calculation of TRM, and recommended approaches for the future, International Transmission provides a description of the MISO approach to TRM. International Transmission states that during the operating horizon (next 48 hours), TRM is limited to a reserve sharing component which only applies to flowgates that are not based on transmission outages (unit tripping and transmission outages are considered a double contingency). International Transmission states that the logic behind this approach is that there are fewer uncertainties in the operating horizon because schedules and market flows are known. International Transmission explains that during the planning horizon (next 48 hours), a two percent TRM component for uncertainty is used on all flowgates, including those requiring reserve sharing TRM. In addition, other assumptions regarding the sale of transmission service enter into the need for TRM to cover "uncertainties." In addition, International Transmission cautions that MISO's minimal two percent margin may not be sufficient for long-term planning horizon requests (i.e., over 13 months) if planning "assumptions" are not reasonable. International Transmission argues that MISO must also employ proper sensitivity studies to other system variables for a two percent margin to be sufficient. TRMs in the five to ten percent range are not necessarily unreasonable if a wide range of potential system operating conditions is not studied. Regardless of the ultimate approach adopted in future standards, International Transmission proposes that all entities follow a consistent framework when calculating TRM.

1118. MidAmerican responds with a discussion of its current approach to TRM calculation, which has been performed in accordance with MAPP-approved methodologies. MidAmerican states that these methodologies include an amount to allow for both the delivery of operating reserves and for uncertainties. Since delivery of operating reserves keeps the interconnected network in service, benefiting all market participants, MidAmerican contends that it is appropriate for TRM to include an amount to allow for the delivery of operating reserves. The allowance for uncertainty is calculated as a percentage of TTC required to protect reliability. All market participants benefit from the provision of an appropriate margin for uncertainty because the reliability of the interconnected network is maintained and service interruptions are reasonably minimized.

1119. With respect to applicable entities, APPA proposes the addition of two new functional entities. Specifically, APPA believes that NERC should expand the applicability section of MOD-008-0 to include planning authorities and reliability coordinators. APPA points out that these are the only entities that can evaluate the amount of error in their transfer capability predictions.

1120. ERCOT states that the Commission's concerns about TRM do not apply to ERCOT, because ERCOT has a balanced grid in which all transmission is firm, no transmission is reserved and there are no transmission paths.

ii. Commission Determination

1121. The Commission does not approve or remand MOD-008-0 until the ERO submits additional information. Consistent with Order No. 890 and comments received in response to the NOPR, the Commission directs the ERO to modify MOD-008-0 through the Reliability Standards development process, as discussed below.

1122. Consistent with the NOPR proposal and Order No. 890, the Commission directs the ERO to modify standard MOD-008-0 to clarify how TRM should be calculated and allocated across paths or flowgates. We understand that the standards drafting process is underway as a joint project with NAESB. We agree with International Transmission, MidAmerican and MISO about the need for more uniformity and transparency in TRM calculation methodology and use, in order to eliminate potential reliability and discrimination concerns. Consistent with Order No. 890, the Commission directs the ERO to specify the parameters for entities to use in determining uncertainties for which TRM can be set aside and used, such as: (1) load forecast and load distribution error; (2) variations in facility loadings; (3) uncertainty in transmission system topology; (4) loop flow impact; (5) variations in generation dispatch; (6) automatic reserve sharing and (7) other uncertainties as identified through the NERC Reliability Standards development process. We find that clear specification in this Final Rule of the permitted purposes for which entities may reserve CBM and TRM will also virtually eliminate double-counting of TRM and CBM. Therefore, we direct the ERO to determine clear requirements regarding permitted uses for TRM through its Reliability Standards development process.

1123. We agree with the commenters that the percentage reduction of line rating can be one way to establish an appropriate maximum TRM if thermal considerations are the only limiting factors. While this is a relatively simple method, it ignores limitations relative to voltage or stability limitations which are the more typical reasons for transmission limitations. If adopted as the Reliability Standard method, it should not restrict a transmission provider from using a more sophisticated method that may allow for greater ATC without reducing overall reliability. However, we disagree with the use of an arbitrary percentage over a long time frame that is not based on either proven historical need or sensitivity studies that support that determination. Therefore, consistent with our OATT Reform Final Rule, we direct the ERO to develop requirements regarding transparency of the documentation that supports TRM determination.

1124. We agree with APPA that NERC should revise the applicability section of this standard to add planning authorities and reliability coordinators, and in addition, any other entities that may be identified in the Reliability Standards development process.

1125. Regarding ERCOT's statement that TRM does not apply to ERCOT, we reiterate our position that any request for a regional exemption from the applicable Reliability Standards must take place in the Reliability Standards development process.

1126. The Commission neither accepts nor remands MOD-008-0 until the ERO submits additional information. In the interim, compliance with MOD-008-0 should continue on a voluntary basis, and the Commission considers compliance with the Reliability Standard to be a matter of good utility practice. Although the Commission did not propose any action with regard to MOD-008-0, it addressed above a number of concerns regarding the Reliability Standard, consistent with those proposed in Order No. 890. Accordingly, we direct the ERO to develop modifications to the Reliability Standard through the Reliability Standards development process including: (1) clear requirements on how TRM should be calculated, including a methodology for determining the maximum TRM value, and allocated across paths; (2) clear requirements for permitted purposes for which TRM can be set aside and used; (3) clear requirements for availability of documentation that supports TRM determination and (4) expanding the applicability to add planning authorities and reliability coordinators and any other appropriate entity identified in the Reliability Standards development process.

k. k. Procedure for Verifying Transmission Reliability Margin Values (MOD-009-0)

1127. MOD-009-0 requires each regional reliability organization to develop and implement a procedure to review TRM calculations and the resulting values determined by member transmission providers to ensure compliance with the regional TRM methodology.

1128. In the NOPR, the Commission identified MOD-009-0 as a fill-in-the-blank standard that requires each regional reliability organization to develop a procedure for review of TRM calculations and the resulting values. In the NOPR, the Commission stated that because the regional procedures had not been submitted, the Commission would not propose to approve or remand MOD-009-0 until the ERO submits the additional information.

i. Comments

1129. APPA agrees that MOD-009-0 is a fill-in-the-blank standard, is not sufficient as currently drafted, and should not be approved as a mandatory Reliability Standard until NERC and the regional reliability organizations and regional entities develop the necessary regional methodologies and the Commission approves them.

ii. Commission Determination

1130. The Commission will not approve or remand MOD-009-0 until the ERO submits additional information. Because the regional procedures have not been submitted to the Commission, it is not possible to determine at this time whether MOD-009-0 satisfies the statutory requirement that a proposed Reliability Standard be "just, reasonable, not unduly discriminatory or preferential, and in the public interest." Accordingly, the Commission neither approves nor remands this Reliability Standard until the regional procedures are submitted. In the interim, compliance with MOD-009-0 should continue on a voluntary basis, and the Commission considers compliance with the Reliability Standard to be a matter of good utility practice.

l. Steady-State Data for Modeling and Simulation of Interconnected Transmission System (MOD-010-0)

1131. The purpose of this Reliability Standard is to establish consistent data requirements, reporting procedures and system models for use in reliability analysis. MOD-010-0 requires the transmission owner, transmission planner, generator owner and resource planner to provide steady-state data, such as equipment characteristics, system data, and existing and future interchange schedules to the regional reliability organization, NERC, and other specified entities.

1132. In the NOPR, the Commission proposed to approve Reliability Standard MOD-010-0 as mandatory and enforceable. In addition, the Commission proposed to direct NERC to submit a modification to MOD-010-0 that: (1) adds a new requirement for transmission owners to provide the list of contingencies they use in performing system operation and planning studies and (2) expands the applicability section to include the planning authority.

i. Comments

1133. APPA agrees with the Commission that MOD-010-0 is sufficient for approval as a mandatory and enforceable Reliability Standard. APPA believes, however, that the Commission's proposed directives to NERC to revise this standard are unduly prescriptive, and may not in fact be the best way to revise the standard.

1134. ISO/RTO Council and ISO-NE do not support adoption of this standard because its requirements refer several times to the data requirements and reporting procedures specified in MOD-011-0, which has been identified by the Commission as a fill-in the-blank standard. ISO/RTO Council and ISO-NE argue that demonstrating compliance with MOD-010-0 is dependent on an unapproved standard, that the unapproved standard lacks some required criteria or procedures that must be developed by the regional reliability organization, that MOD-010-0 cannot be effectively implemented, and that responsible entities therefore should not be subject to compliance with an incomplete standard.

1135. Constellation strongly supports the Commission's proposals with respect to MOD-010-O and MOD-012-0 because these proposals, together with other initiatives, such as OATT reform, represent additional steps not only to achieving a reliable bulk power system, but also to reducing undue discrimination in transmission services. Constellation supports the Commission's proposals because they will involve generation owners in facility ratings discussions and discussions of other limiting components and will provide more clarity in the requirements of the Reliability Standard, making enforcement more objective and robust.

1136. Many commenters submitted comments both supporting and opposing the Commission's proposal to modify the standard to require listing the contingencies that transmission owners use when they perform system operation and planning studies.

1137. FirstEnergy supports the Commission's proposal to require transmission owners to provide the list of contingencies used in performing system operation and planning studies. FirstEnergy emphasizes that such a requirement, however, should accommodate various electronic formats that are commonly used in industry simulation tools. FirstEnergy states that compliance with this Reliability Standard should not require transmission owners to replace existing computer and/or software systems, and that the new standard should also require the regional reliability organizations (or Regional Entities) to coordinate the lists of contingencies across wide-areas.

1138. In its support of the Commission's proposal, MidAmerican and TANC stress that a requirement that the transmission owner provide a list of contingencies to neighboring systems will benefit reliability by enabling neighboring systems to accurately study the effects of contingencies on their own systems. In its concurring comments, TANC recommends that the Commission clarify that the list of the contingencies that are used in performing system operation and planning studies include all the contingencies, N-1, N-2, as well as multiple contingencies.

1139. MidAmerican cautions that a list of contingencies could be used in a "cook-book" manner to reach the wrong conclusions. A contingency must be modeled in specific and appropriate conditions to understand the reliability issues associated with the contingency.[351] Similarly, NERC states that there may be a need to better understand the reliability need for transmission owners to provide a list of contingencies and to whom the list should be provided.

1140. Northern Indiana and MidAmerican note that such a list of contingencies should be considered a particularly sensitive form of CEII since it would be a list of events that, when they occur, cause critical situations on a system. Northern Indiana and MidAmerican argue that the Commission should include the need to provide for protection against public disclosure through the NERC administrative process in its discussion of any final Reliability Standard. In addition, California Cogeneration states that Requirements R1 and R2 of this standard should not apply to entities that have no material impact on the grid. California Cogeneration warns that the standard may also require generator owners to provide data on behind-the-meter operations, the provision of which should be seriously limited, and data on future interchange schedules, the confidentiality of which should be maintained.

1141. PG&E and Xcel oppose the proposed modification requiring a list of contingencies stating that the requirement is unnecessary and would be unduly burdensome. Xcel also states that the modification would not prove to be useful to neighboring systems. No such lists are currently developed or maintained today. Rather, the contingencies are reflected in the computerized models used by transmission providers for both transmission planning and operations. The models are regularly updated as new facilities are installed. If transmission operators are required to develop such lists, they would be so long and subject to constant change that they would not only be burdensome to develop and maintain, but also unlikely to provide useful information for other transmission owners.

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[351] MidAmerican further cautions that other contingencies exist that must be studied under still-different conditions. Advanced applications associated with real-time contingency analysis review an extensive list of events in combination with other events. Ahead of time, there is no way to be sure exactly which events are the worst in any given operating condition. A single reliability standard cannot contain all the coordination that is needed to allow a system to fully understand all the reliability challenges of a neighboring system. Thus, MidAmerican contends that a better approach is to continue the joint operational and long-term planning that planning authorities, reliability coordinators and other regional entities are currently conducting with transmission planners, transmission owners and others to ensure that the interconnected network is operated and planned in a coordinated way.

1142. In its opposition to releasing a list of contingencies, PG&E states that performing transmission planning studies is an ambiguous part of the duties of a transmission owner under the NERC Functional Model. Further clarification and refinement of the responsibilities of each entity under the NERC Functional Model may indicate that such studies are among a transmission owner's duties. Until that happens, however, requiring transmission owners to provide contingencies used in performing system operation and planning studies is inappropriate.

1143. SoCal Edison and TVA state that the entity that should be responsible for providing a list of contingencies in performing planning and operation studies is the transmission planner, not the transmission owner. APPA also believes that the transmission operator should be one of the entities required to list contingencies used to perform studies, and that the transmission owner function should be removed as an applicable entity. APPA further notes that the transmission owner does no studies regarding operations or planning. A transmission owner merely owns transmission facilities and maintains those facilities. Moreover, APPA argues that existing studies performed by the transmission planner for the regional reliability organization or planning authority will include a list of contingencies.

1144. Regarding the Commission's proposal to expand the applicability section of this Reliability Standard to include the planning authority, APPA disagrees and recites the comments of MRO, Reliability First and PG&E on the Staff Preliminary Assessment,[352] that to require the planning authority to provide all of this information is duplicative and unnecessary. APPA believes that NERC, as the entity charged with developing standards, is best-suited to address all of these concerns and to develop a consensus standard using its Reliability Standard development process.

1145. TAPS states that this standard would impose unnecessary costs on small systems without improving reliability if applied without the limitation of NERC's bulk electric system definition and NERC's June registry criteria. TAPS opines that modeling will be complicated by the incorporation of low voltage or radial transmission facilities or small generators that have no material impact on bulk transmission system reliability, without improving the results. TAPS further argues that NERC and the Regional Entities – not the Commission – should determine the level of modeling required for reliability.

[352] NOPR at P 663.

ii. Commission Determination

1146. The Commission approves MOD-010-0. In addition, the Commission requires the ERO to modify MOD-010-0 as described below.

1147. As an initial matter, the Commission disagrees that MOD-010-0 cannot be implemented until MOD-011-0 is modified. We have directed that data collection and reporting procedures not be interrupted while MOD-011-0 is being modified. Therefore it is possible to implement MOD-010-0. Failure to have the data needed for the steady-state analysis would halt regional reliability assessment processes and hinder planners from accurately predicting future system conditions, which would be detrimental to system reliability. We therefore direct the ERO to use its authority pursuant to § 39.2(d) of our regulations to require users, owners and operators to provide to the Regional Entity the information related to data gathering, data maintenance, reliability assessments and other process-type functions. As we discuss below in the section on MOD-011-0, we direct the ERO to develop a Work Plan that will facilitate ongoing collection of the steady-state modeling and simulation data set forth in MOD-011-0, and submit a compliance filing with that Work Plan.

1148. Supported by many commenters, we adopt the NOPR proposal to direct the ERO to modify MOD-010-0 to require filing of all of the contingencies that are used in performing steady-state system operation and planning studies. We believe that access to such information will enable planners to accurately study the effects of contingencies occurring in neighboring systems on their own systems, which will benefit reliability. Because of the lack of information on contingency outages and the automatic actions that result from these contingencies, planners have not been able to analyze neighboring conditions accurately, thereby potentially jeopardizing reliability on their own and surrounding systems. This requirement will make transmission planning data more transparent, consistent with Order No. 890 requiring greater openness of the transmission planning process.

1149. With respect to TANC's recommendation to modify the standard to require utilities to provide lists of all contingencies they use to operate and plan their systems (N-1, N-2, multiple), we clarify that our requirement specifies contingency files used for all operations and planning. We do not limit the provision of contingency information to single, double or multiple outages. Utilities must provide lists of all the contingencies they use in operations and planning, provided in their original format, regardless of how this data is organized.

1150. In response to MidAmerican, NERC and TANC's concerns that the contingency lists could be used as a "cook-book," our expectation is that utility planners that use these files will have sufficient experience to use them appropriately. We expect that most utility planners are already familiar with their neighbors' system topologies, and have the means, such as bus abbreviation directories and switching diagrams, to identify facilities listed in contingency files.

1151. We agree with FirstEnergy's comments regarding the importance of using existing data collection systems so as to not impose any additional costs on entities. They may file the contingency files in the electronic format in which they were created, along with any necessary decoding instructions. We therefore disagree with PG&E, TAPS and Xcel that this Reliability Standard will be unduly burdensome since it only requires the provision of files that must be developed during the utility's usual planning and operations study process.

1152. Consistent with California Cogeneration, Northern Indiana and MidAmerican's concerns, we determine that those data that a company considers confidential, commercially-sensitive or security-sensitive should be released in accordance with the CEII process or subject to confidentiality agreements. We direct the ERO to address confidentiality issues and modify the Reliability Standard as necessary through its Reliability Standards development process.

1153. We disagree with commenters that generators or small entities that do not have a material impact on grid reliability should be automatically exempt from providing the data required by this Reliability Standard. The Commission believes that all entities that are required to register under the registration process that we have approved must provide data requested by the ERO or the Regional Entity.

1154. We agree with APPA, SoCal Edison and TVA that the functional entity responsible for providing the list of contingencies in performing planning studies should be the transmission planner, instead of the transmission owner, as proposed in the NOPR. We also agree with APPA that the transmission operator should be one of the entities required to list contingencies used to perform operational studies. Transmission operators are usually responsible for compiling the operational contingency lists for both normal and conservative operation. Therefore, we direct the ERO to modify MOD-010-0 to include transmission operators as an applicable entity.

1155. We adopt our NOPR proposal that the planning authority should be included in this Reliability Standard because the planning authority is the entity responsible for the coordination and integration of transmission facilities and resource plans, as well as one of the entities responsible for the integrity and consistency of the data. We disagree with APPA that it is duplicative and unnecessary to require the planning authority to provide all of this information. However, we direct the ERO, as the entity charged with developing Reliability Standards, to address all of these concerns and to develop a consensus standard using its Reliability Standard development process.

1156. Accordingly, the Commission approves MOD-010-0 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification to MOD-010-0 through the Reliability Standards development process that: (1) adds a new requirement in MOD-010-1 for transmission planners to provide the contingency lists they use in performing system operation and planning studies, contained in the electronic format in which they were created, along with any necessary decoding instructions and (2) expands the applicability section to include transmission operators and the planning authority. We also direct the ERO to address confidentiality and small entity issues through the Reliability Standards development process.

m. Maintenance and Distribution of Steady-State Data Requirements and Reporting Procedures (MOD-011-0)

1157. The purpose of MOD-011-0 is to establish consistent data requirements, reporting procedures and system models for use in reliability analysis. This Reliability Standard requires the regional reliability organizations to develop comprehensive steady-state data requirements and reporting procedures needed to model and analyze the steady-state conditions for each Interconnection.

1158. In the NOPR, the Commission identified MOD-011-0 as a fill-in-the-blank standard that requires each regional reliability organization to develop comprehensive steady-state data requirements and reporting procedures needed to model and analyze the steady-state conditions for each Interconnection. The NOPR stated that because the regional methodologies had not been submitted, the Commission would not propose to approve or remand MOD-011-0 until the ERO submits the additional information. In addition, the NOPR suggested that the planning authority plays a significant role in integration of data and thus should be included in the applicability section of MOD-011-0.

i. Comments

1159. APPA agrees with the Commission that this standard is a fill-in-the-blank standard, is not sufficient as currently drafted and should not be approved as a mandatory reliability standard until NERC and the Regional Entities develop the necessary methodologies and the Commission approves them.

1160. TANC supports replacing the term regional reliability organization with an entity from the NERC Functional Model.

ii. Commission Determination

1161. The Commission will not approve or remand MOD-011-0 until the ERO submits additional information. The Commission directs the ERO to modify MOD-011-0 as discussed below.

1162. We reiterate our position stated in the NOPR that the planning authority should be included in this Reliability Standard because the planning authority is the entity responsible for the coordination and integration of transmission facilities and resource planning, as well as one of the entities responsible for the integrity and consistency of the data. Therefore, we direct the ERO to add the planning authority to the applicability section of this Reliability Standard.

1163. In response to concerns raised in MOD-010-0 about implementing MOD-010-0 without the data to be collected when MOD-011-0 is modified, we direct the ERO to develop a Work Plan that will facilitate ongoing collection of the steady-state modeling and simulation data specified in MOD-011-0.

1164. Accordingly, the Commission neither accepts nor remands MOD-011-0 until the ERO submits additional information. Because the regional procedures have not been submitted to the Commission, it is not possible to determine at this time whether MOD-011-0 satisfies the statutory requirement that a proposed Reliability Standard be "just, reasonable, not unduly discriminatory or preferential, and in the public interest." In the interim, compliance with MOD-011-0 should continue on a voluntary basis, and the Commission considers compliance with the Reliability Standard to be a matter of good utility practice. We direct the ERO to modify the Reliability Standard through the Reliability Standards development process to expand the applicability section to include the planning authority. Additionally, we direct the ERO to develop a Work Plan and submit a compliance filing that will facilitate ongoing collection of the steady-state modeling and simulation data specified in MOD-011-0.

n. Dynamics Data for Modeling and Simulation of the Interconnected Transmission System (MOD-012-0)

1165. The purpose of MOD-012-0 is to establish consistent data requirements, reporting procedures and system models for use in reliability analysis. MOD-012-0 requires transmission owners, transmission planners, generator owners and resource planners to provide dynamic system modeling and simulation data, such as equipment characteristics and system data, to the regional reliability organization, NERC and other specified entities.

1166. In the NOPR, the Commission proposed to approve Reliability Standard MOD-012-0 as mandatory and enforceable. In addition, the Commission proposed to direct NERC to submit a modification to MOD-012-0 that: (1) adds a new requirement for transmission owners to provide the list of faults or disturbances they use in performing dynamics system modeling analysis for system operation and planning and (2) expands the applicability section to include the planning authority.

i. Comments

1167. APPA and PG&E agree that the Commission should approve MOD-012-0 as a mandatory and enforceable Reliability Standard. However, PG&E requests the Commission to approve this standard without any modifications. In addition, APPA states that the Commission's proposed directives to NERC to revise this standard are unduly prescriptive, and may not in fact be the best way to revise the standard. APPA notes that NERC, as the technical expert body charged with developing standards, is the entity best suited to hear all of these concerns, and to develop a consensus standard using its Reliability Standards development process.

1168. ISO/RTO Council and ISO-NE disagree with the Commission's proposal to approve this standard, and state that the MOD-012-0 requirements refer several times to the "data requirements and reporting procedures of MOD-013-0," which has been identified by the Commission as a fill-in-the-blank standard, and is pending. Consequently, they argue that MOD-012-0 cannot be effectively implemented, and responsible entities should therefore not be subject to compliance with an incomplete standard.

1169. With respect to the Commission's proposal for adding a new requirement to this standard, FirstEnergy notes that it is appropriate for the Commission to require transmission owners to provide the list of faults or disturbances used in performing dynamics system studies. However, FirstEnergy cautions that such requirement should accommodate various electronic formats that are commonly used in industry simulation tools. FirstEnergy states that compliance with this provision should not require transmission owners to replace existing computer and/or software systems, and that the new standard should also require the regional reliability organizations (or Regional Entities) to coordinate the lists of faults or disturbances across wide-areas.

1170. MidAmerican agrees that requiring transmission owners to provide a list of faults or disturbances to neighboring systems would provide for additional coordination between neighboring utilities, and therefore, would be an improvement to the standard.

However, MidAmerican warns that a list of faults and disturbances could be used in a "cook-book" manner to reach the wrong conclusions.[353]

1171. Northern Indiana and MidAmerican note that such a list of faults and disturbances should be considered a particularly sensitive form of CEII since it would be a list of events that, when they occur, cause critical problems on the system. Northern Indiana and MidAmerican request the Commission to protect sensitive information through the NERC administrative process discussed in the TOP-005-1 Reliability Standard.

1172. Xcel raises the same concern it stated about MOD-010-0 that the proposed modification related to a list of faults and disturbances is unduly burdensome and would not prove useful to neighboring systems. Xcel states that no such lists are currently developed or maintained today, but that the faults and disturbances are reflected in the computerized models used by transmission providers for both transmission planning and operations, which are regularly updated as new facilities are installed. Xcel cautions that the lists, as proposed by the Commission, would be so long and subject to constant change that they would not only be burdensome to develop and maintain, but also unlikely to provide usable information for other transmission owners.

1173. PG&E disagrees with the Commission's proposal related to lists of faults and disturbances, and repeats its comments from MOD-010-0 that this new requirement is unnecessary.

1174. Regarding the functional entities to which this standard applies, APPA notes that the transmission operator and transmission planner, as functions required to provide information regarding stability studies, should be added to the list of applicable entities, while transmission owners should be removed from such list. Under the NERC

[353] MidAmerican further discusses that the Commission should recognize that caution must be taken in assuming that no other faults and disturbances exist that must be studied under other conditions. MidAmerican states that like with MOD-010-0, ahead of time, there is no way to be sure exactly which faults and disturbances are the worst under given operating conditions. A single reliability standard cannot contain all the coordination needed to allow each system operator to fully understand all the reliability challenges of a neighboring system. Perhaps a better approach is to continue the joint operational and long-term planning that is currently being conducted by planning authorities, reliability coordinators and other regional entities with transmission planners, transmission owners and others to ensure that the interconnected network is operated and planned in a coordinated way.

Functional Model, transmission owners do not perform any studies related to MOD-012-0. Rather, a transmission owner merely owns transmission facilities and maintains them.

1175. California Cogeneration states that this standard raises concerns about data collection and the cost of compliance, and therefore a mechanism for determining no material impact and a provision for exemption is essential for this standard. California Cogeneration also believes that it is unclear what data is included in "dynamics system modeling and simulation data," and whether independent generators would have such data.

ii. <u>Commission Determination</u>

1176. The Commission approves MOD-012-0 as mandatory and enforceable. The Commission directs the ERO to modify MOD-012-0 as discussed below.

1177. As an initial matter, the Commission disagrees that MOD-012-0 cannot be implemented until MOD-013-1 is modified. We have directed that data collection and reporting procedures not be interrupted while MOD-013-1 is being revised, therefore it is possible to implement MOD-012-0. Failure to provide the data needed for dynamics system modeling and simulation would halt regional reliability assessment processes and impede planners from accurately predicting future system conditions, which would be detrimental to system reliability. We therefore direct the ERO to use its authority pursuant to § 39.2(d) of our regulations to require users, owners and operators to provide to the Regional Entities the information related to data gathering, data maintenance, reliability assessments and other process type functions. As we will discuss in the next section on MOD-013-1, we require the ERO to develop a Work Plan and submit a compliance filing that will facilitate ongoing collection of the dynamics system modeling and simulation data specified by the deferred MOD-013-1 Reliability Standard, which is necessary for implementation of MOD-012-0.

1178. Supported by several commenters, we adopt the NOPR proposal and direct the ERO to modify MOD-012-0 by adding a new requirement to provide a list of the faults and disturbances used in performing dynamics system studies for system operation and planning. We believe that access to such information will enable planners to accurately study the effects of disturbances occurring in neighboring systems on their own systems, which will benefit reliability. This requirement will also make transmission planning data more transparent, consistent with Order No. 890, which calls for greater openness of the transmission planning process on a regional basis.

1179. In response to MidAmerican's concern that fault and disturbance information could be used as a "cook-book," our expectation is that utility planners who use this data have sufficient experience to use it and interpret the results correctly. We expect that most utility planners are already familiar with their neighbors' system topologies, and will be capable of identifying facilities on fault and disturbance lists.

1180. We agree with FirstEnergy's concerns regarding the importance of using existing data collection systems so as to not impose any additional costs on entities. They may file the fault and disturbance information in the electronic format in which they were created, along with any necessary decoding instructions. Compliance with this provision should not require transmission planners to replace existing computer and/or software systems. Therefore, we disagree with PG&E and Xcel that this standard modification will be unduly burdensome.

1181. Consistent with California Cogeneration, Northern Indiana and MidAmerican's concerns, we determine that the data that a company considers confidential, market-sensitive or security-sensitive should be released in accordance with the CEII process or subject to confidentiality agreements. We direct the ERO to address confidentiality issues and modify the standard as necessary through its Reliability Standards development process.

1182. We disagree with commenters that generators or small entities that do not have a material impact on grid reliability should be automatically exempt from providing the data required by this Reliability Standard. The Commission believes that all entities that are required to register under the registration process that we have approved must provide data requested by the ERO or the Regional Entity.

1183. We agree with APPA that the functional entity responsible for providing the fault and disturbance list should be the transmission planner, instead of the transmission owner, as proposed in the NOPR. We also agree with APPA that the transmission operator should be added to the list of applicable entities in the Reliability Standards development process. Therefore, we direct the ERO to modify MOD-012-0 to require the transmission planner to provide fault and disturbance lists.

1184. We adopt our NOPR proposal that planning authorities should be included in this Reliability Standard because the planning authority is the entity responsible for the coordination and integration of transmission facilities and resource plans, as well as one of the entities responsible for the integrity and consistency of the data. We therefore direct the ERO to add the planning authority to the list of applicable entities.

1185. Accordingly, the Commission approves MOD-012-0 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification to MOD-012-0 through the Reliability Standards development process that: (1) adds a new requirement for transmission planners to provide the list of faults and disturbances they use in performing dynamic stability analysis in the electronic format in which they were created, along with any necessary decoding instructions and (2) expands the applicability section to include transmission operators, planning authorities and transmission planners. We expect the ERO to address confidentiality issues and modify the Reliability Standard as necessary through the Reliability Standards development process.

o. Maintenance and Distribution of Dynamics Data Requirements and Reporting Procedures (MOD-013-1)

1186. MOD-013-1 requires the regional reliability organizations within an Interconnection to develop comprehensive dynamics data requirements and reporting procedures needed to model and analyze the dynamic behavior and response of each Interconnection. More specifically, the regional reliability organization, in coordination with its transmission owners, transmission planners, generator owners and resource planners within an Interconnection, is required to: (1) participate in development of documentation for their Interconnection data requirements and reporting procedures; (2) participate in the review of those data requirements and reporting procedures at least every five years and (3) make the data requirements and reporting procedures available to NERC and other specified entities upon request.

1187. In the NOPR, the Commission identified MOD-013-1 as a fill-in-the-blank standard that requires each regional reliability organization within an Interconnection to develop comprehensive dynamics data requirements and reporting procedures needed to model and analyze the dynamic behavior and response for each of the three NERC Interconnections. The NOPR stated that because the regional methodologies had not been submitted, the Commission would not propose to approve or remand MOD-013-1 until the ERO submits additional information. In addition, in the NOPR we agreed that the Reliability Standard should apply to the planning authority.

1188. In the NOPR, the Commission expressed a concern regarding the 1990 cut-off date,[354] and shared PG&E's concern that the difficulty in obtaining unit-specific data is not limited to the age, but may also be due to other factors such as unit configuration. The Commission requested comment whether it is reasonable to permit entities to estimate dynamics data if they are unable to obtain unit specific data for any reason. The Commission believes that to achieve the goal of this Reliability Standard of having the ability to accurately model and analyze the dynamic behavior and response of each Interconnection, it is necessary to have accurate data. Inaccurate data can lead to

[354] Requirement R1.1.1 allows for the use of estimated or typical manufacturer's data on pre-1990 units to model dynamic behavior when unit-specific data is unavailable.

unrealistic simulations and inappropriate actions by responsible entities which may jeopardize the reliability of the Bulk-Power System.

i. Comments

1189. APPA agrees with the Commission that MOD-013-1 is a fill-in-the-blank standard, is not sufficient as currently drafted, and should not be approved as a mandatory Reliability Standard until NERC and the regional reliability organizations/Regional Entities develop the necessary regional methodologies and the Commission approves them.

1190. In response to the Commission's request for comments on whether it is reasonable to permit entities to estimate dynamics data if they are unable to obtain unit specific data for any reason, many commenters responded that it is reasonable to allow estimation of dynamics data for older units where data is not available.[355] The Small Entities Forum expects that the Reliability Standard ultimately will include requirements that such estimates be based on sound engineering principles and be subject to technical review and approval of any estimates at the regional level.

1191. MidAmerican explains that there may be safety or system conditions and/or the loss of records that do not permit gathering unit-specific information, and that in such cases, computations and engineering reports of estimated capability should be sufficient. MidAmerican also requests that if there is a farm of similar generation units (such as wind turbines) or synchronous condensers located in the same general area, providing unit-specific information for a number of identical units is not necessary. Instead, MidAmerican proposes that information about a sample of the identical units (such as two) should be sufficient to provide enough unit-specific information to be representative of the farm. MidAmerican also notes that if units are located in a part of the system that does not typically demonstrate instability, the value of unit-specific data is reduced, and that there are a number of such circumstances in which provision of unit-specific data should not be required.

1192. International Transmission, stating that the age of the unit alone may not be the only reason why unit-specific data might be unavailable, cautions that there should be a requirement in every case that unit data actually be sought for all generating units before estimates of dynamics data are used. International Transmission believes that achieving the most accurate possible picture of the dynamic behavior of the Interconnection

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[355] EEI, LPPC, MidAmerican, Small Entities Forum and TVA.

requires the use of actual data, and that, at a minimum, entities should be required to document the steps taken to obtain unit-specific data.

1193. APPA, however, expresses its concern regarding the difficulties in obtaining accurate unit-specific data to model dynamic behavior. APPA recommends to NERC that the regional reliability organizations/Regional Entities and the reliability coordinators review this type of data on a case-by-case basis to test it for accuracy and to determine whether estimated data will produce outputs from the models within acceptable limits. International Transmission confirms that testing is easily accomplished, and provides up-to-date dynamics data reflective of the natural degradation of generating units over their lifetimes. However, International Transmission says that this effort could be tied to the Generator Model Validation Reliability Standards (MOD-024-1 and MOD-025-1).

1194. TANC agrees with the Commission that the standard requirement is arbitrary in imposing the 1990 cut-off with regard to modeling dynamic behavior. TANC believes that this requirement allows for the use of estimated or typical manufacturer's data on pre-1990 units to model dynamic behavior when unit-specific data is unavailable. TANC notes that difficulty in obtaining unit specific data is not limited to the age of the unit but also unit configuration. TANC therefore recommends that the 1990 cut-off be removed from the proposed Reliability Standard because there is no justifiable basis for the arbitrary cut-off and that the Reliability Standard be revised to allow the generally-accepted use of estimated or typical manufacturer data where unit-specific data is impractical to obtain. TVA agrees that the 1990 cut-off date is unnecessary.

1195. In contrast to those who support rejecting the 1990 cut-off requirement, FirstEnergy states that unit-specific data should be required for all units installed after 1990. EEI confirms that unit-specific information should be available for most units placed in service since 1990.

ii. Commission Determination

1196. The Commission will not approve or remand MOD-013-1 until the ERO submits additional information. The Commission directs the ERO to modify MOD-013-1 through the Reliability Standards development process as discussed below.

1197. We agree with many commenters and direct the ERO to modify the Reliability Standard to permit entities to estimate dynamics data if they are unable to obtain unit-specific data for any reason, not just for units constructed prior to 1990. Achieving the most accurate possible picture of the dynamic behavior of the Interconnection requires the use of actual data. We disagree with FirstEnergy and EEI and reject the 1990 cut-off date, because the age of the unit alone may not be the only reason why unit-specific data is unavailable. We agree with the Small Entities Forum that the Reliability Standard should include Requirements that such estimates be based on sound engineering principles and be subject to technical review and approval of any estimates at the regional level. That said, the Commission directs that this Reliability Standard be modified to require that the results of these dynamics models be compared with actual disturbance data to verify the accuracy of the models.

1198. With respect to small units installed in wind farms, we agree with MidAmerican that data for one unit to represent all identical units at wind farms is acceptable. The Commission understands that this is the current approach with any generator that is manufactured in quantity such as multiple generators used in combined cycle plants.

1199. We adopt our NOPR proposal and direct the ERO to expand the applicability section in this Reliability Standard to include planning authorities because they are the entities responsible for the coordination and integration of transmission facilities and resource plans, as well as one of the entities responsible for the integrity and consistency of the data.

1200. Accordingly, the Commission neither accepts nor remands MOD-013-1 until the ERO submits additional information. Because the regional procedures have not been submitted to the Commission, it is not possible to determine at this time whether MOD-013-1 satisfies the statutory requirement that a proposed Reliability Standard be "just, reasonable, not unduly discriminatory or preferential, and in the public interest." In the interim, compliance with MOD-013-1 should continue on a voluntary basis, and the Commission considers compliance with the Reliability Standard to be a matter of good utility practice. Although the Commission does not approve or remand MOD-013-1, we direct the ERO to modify it through the Reliability Standards development process to: (1) permit entities to estimate dynamics data if they are unable to obtain unit specific data for any reason; (2) require verification of the dynamic models with actual disturbance data and (3) expand the applicability section to include the planning authority, transmission operator and transmission planner. As discussed above in MOD-012-0, we direct the ERO to develop a Work Plan that will facilitate ongoing collection of the dynamics system modeling and simulation data specified in MOD-013-1, and submit a compliance filing containing this Work Plan to the Commission.

p. Development of Steady-State System Models (MOD-014-0)

1201. MOD-014-0 requires the regional reliability organizations within each Interconnection to coordinate and jointly develop and maintain a library of solved Interconnection-specific steady-state models. These models are to include near- and long-term planning horizons representing system conditions for various demand levels. The models are to be updated annually.

1202. In the NOPR, the Commission identified MOD-014-0 as a fill-in-the-blank standard that requires the regional reliability organizations within an Interconnection to develop, coordinate and maintain a library of solved Interconnection-specific steady-state models. The NOPR stated that because the regional procedures had not been submitted, the Commission would not propose to approve or remand MOD-014-0 until the ERO submits the additional information. In addition, in the NOPR the Commission stated its belief that the Reliability Standard should be modified to include a requirement to verify that steady-state models are accurate.

1203. In the NOPR, the Commission expressed concern about creating a duplicate effort if both the transmission owner and the regional reliability organization separately develop the steady-state base cases required for the FERC Form 715 filing and for MOD-014-0. The NOPR suggested that the Reliability Standard contain a requirement specifying the time period and planning years be identical to those found in FERC Form 715.[356] Further, the Commission requested comments on any incompatibility between requirements under FERC Form 715 and MOD-014-0.

i. Comments

1204. APPA agrees with the Commission that MOD-014-0, a fill-in-the-blank standard, is not sufficient as currently drafted, and should not be approved as a mandatory Reliability Standard until NERC and the regional reliability organizations/Regional Entities develop the necessary regional methodologies and the Commission approves them.

1205. NRC suggests that a periodic verification against field data needs to be included in this Reliability Standard.

1206. Regarding the Commission's request for comments on any incompatibility between requirements under FERC Form 715 and MOD-014-0, International Transmission states that the language in MOD-014-0 would allow the regional reliability organization and the transmission owner to develop separate base cases. International Transmission notes that its experience with current practice suggests, however, that this is not a significant concern. Transmission owners now develop the information for

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[356] FERC Form 715 is available at http://www.ferc.gov/docs-filing/eforms.asp#715.

inclusion in a regional base case, and the regional base case is rolled up into a FERC Form 715 filing by a regional entity. International Transmission expects that this process would continue in the future.

1207. MISO believes that FERC should revisit the need for transmission owners to have base case information available for replication. MISO states that the current Interconnection trend is for transmission owners to work together more closely in developing large assessments based on a large model, and that these large assessments are better guides to the overall capability of the transmission grid to move power. MISO believes that these assessments should be filed as part of FERC Form 715.

1208. Although Northern Indiana does not see any duplication or incompatibility with FERC Form 715, Northern Indiana is concerned that the proposed Reliability Standard envisions the use of steady-state models and benchmarking for long-term planning. Northern Indiana believes that benchmarking of planning models should be directed towards validation of line constraints and general comparison of modeled to actual load levels. Northern Indiana suggests that this could be accomplished through validation processes that would first evaluate the data used to model the transformers and the lines and determine that such data is correct, and then compare the loads in total against the actual loads, followed by an examination of individual load points on a system.

ii. Commission Determination

1209. The Commission will not approve or remand MOD-014-0 until the ERO submits additional information. Because the regional procedures have not been submitted to the Commission, it is not possible to determine at this time whether MOD-014-0 satisfies the statutory requirement that a proposed Reliability Standard be "just, reasonable, not unduly discriminatory or preferential, and in the public interest." The Commission directs the ERO to modify MOD-014-0 as discussed below.

1210. We maintain our position set forth in the NOPR that analysis of the Interconnection system behavior requires the use of accurate steady-state models. Therefore, we direct the ERO to modify the Reliability Standard to include a requirement that the models be validated against actual system responses. We understand that NERC is incorporating recommendations from the Blackout Report[357] and developing models for the Eastern Interconnection.

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[357] Recommendation Number 24 of the Blackout Report at 160.

1211. Further, the maximum discrepancy between the model results and the actual system response should be specified in the Reliability Standard. The Commission believes that the maximum discrepancy between the actual system performance and the model should be small enough that decisions made by planning entities based on output from the model would be consistent with the decisions of operating entities based on actual system response. We direct the ERO to modify MOD-014-0 through the Reliability Standards development process to require that actual system events be simulated and if the model output is not within the accuracy required, the model shall be modified to achieve the necessary accuracy.

1212. We believe that steady-state model validation should not be interrupted while MOD-014-0 is being modified. The lack of accurate models needed for the simulations would halt regional reliability assessment processes and hinder planners from accurately predicting future system conditions, which would be detrimental to system reliability. We therefore direct the ERO to use its authority pursuant to § 39.2(d) of our regulations to require users, owners and operators to provide the validated models to regional reliability organizations. We direct the ERO to develop a Work Plan that will facilitate ongoing validation of steady-state models and submit a compliance filing containing the Work Plan with the Commission.

1213. Consistent with many commenters' responses, we find changes to FERC Form 715 are not necessary at this time, because there is no conflict between data gathering and model construction with the FERC Form 715 process.

1214. The Commission neither accepts nor remands MOD-014-0. Because the regional procedures have not been submitted to the Commission, it is not possible to determine at this time whether MOD-014-0 satisfies the statutory requirement that a proposed Reliability Standard be "just, reasonable, not unduly discriminatory or preferential, and in the public interest." In the interim, compliance with MOD-014-0 should continue on a voluntary basis, and the Commission considers compliance with the Reliability Standard to be a matter of good utility practice. We direct the ERO to: (1) modify the Reliability Standard through the Reliability Standards development process to require actual system events be simulated and model output validated against actual system responses and (2) develop a Work Plan and submit a compliance filing that will enable validation of the steady-state models while MOD-014-0 is being modified.

q. Development of Dynamics System Models (MOD-015-0)

1215. MOD-015-0 requires the regional reliability organizations within each Interconnection to coordinate and jointly develop and maintain a library of initialized (with no faults and disturbances) Interconnection-specific dynamics system models.

These models represent near-term years and the years chosen from the longer-term planning horizon.

1216. In the NOPR, the Commission identified MOD-015-0 as a fill-in-the-blank standard that requires the regional reliability organizations within an Interconnection to develop, coordinate and maintain a library of initialized Interconnection-specific dynamics system models. The NOPR stated that because the regional procedures had not been submitted, the Commission would not propose to approve or remand MOD-015-0 until the ERO submits the additional information. In addition, the Commission stated that MOD-015-0 should include a requirement to verify accuracy of dynamics system models.

i. Comments

1217. APPA agrees that MOD-015-0 is a fill-in-the-blank standard, is not sufficient as currently drafted and should not be approved as a mandatory reliability standard until NERC and the regional reliability organizations/Regional Entities develop the necessary regional methodologies and the Commission approves them.

1218. EEI agrees with the Commission's proposal that a new requirement for verification of the accuracy of dynamics system models should be a part of this Reliability Standard. In addition, EEI states that the validation of models is a valid concern, but that any requirement in this area should be carefully considered, and that any requirement should be related to using the models to replicate events that occur on the system instead of developing separate testing procedures to verify the models. EEI believes that it would not be reasonable to subject generation units to artificial disturbances to validate the models. NRC recommends periodic verification against field data. APPA notes that if NERC modifies MOD-015-0 as APPA anticipates, a requirement to verify the accuracy of the dynamics system model would be included and the Regional Entity would be the compliance monitor.

ii. Commission Determination

1219. The Commission will not approve or remand MOD-015-0 until the ERO submits additional information. Because the regional procedures have not been submitted to the Commission, it is not possible to determine at this time whether MOD-015-0 satisfies the statutory requirement that a proposed Reliability Standard be "just, reasonable, not unduly discriminatory or preferential, and in the public interest." The Commission directs the ERO to modify MOD-015-0 through the Reliability Standards development process as discussed below.

1220. We maintain our position set forth in the NOPR that the analysis of Interconnection system behavior requires the use of accurate dynamics system models. Therefore, we direct the ERO to modify the Reliability Standard to include a requirement that the models be validated against actual system responses. We agree with EEI and NRC and confirm our position that a requirement to verify that dynamics system models are accurate should be a part of this Reliability Standard. We agree with EEI that this new requirement should be related to using the models to replicate events that occur on the system instead of developing separate testing procedures to verify the models. We direct the ERO to modify the standard to require actual system events be simulated and dynamics system model output be validated against actual system responses.

1221. We believe that dynamics system model validation should not be interrupted while MOD-015-0 is in the modification process. The lack of accurate models needed for the simulations would halt regional reliability assessment processes and hinder planners from accurately predicting future system conditions, which would be detrimental to system reliability. We therefore direct the ERO to use its authority pursuant to § 39.2(d) of our regulations to require users, owners and operators to provide to the Regional Entity the validated dynamics system models while MOD-015-0 is being modified. We require the ERO to develop a Work Plan that will enable continual validation of dynamics system models and submit a compliance filing with the Commission.

1222. The Commission neither accepts nor remands MOD-015-0 until the ERO submits additional information. Because the regional procedures have not been submitted to the Commission, it is not possible to determine at this time whether MOD-015-0 satisfies the statutory requirement that a proposed Reliability Standard be "just, reasonable, not unduly discriminatory or preferential, and in the public interest." In the interim, compliance with MOD-015-0 should continue on a voluntary basis, and the Commission considers compliance with the Reliability Standard to be a matter of good utility practice. We direct the ERO to: (1) modify the Reliability Standard through the Reliability Standards development process to require verification of the accuracy of dynamics system models and (2) develop a Work Plan and submit a compliance filing that will facilitate ongoing verification of the accuracy of dynamics system models while MOD-015-0 is being modified.

r. Documentation of Data Reporting Requirements for Actual and Forecast Demands, Net Energy for Load and Controllable Demand-Side Management (MOD-016-1)

1223. The purpose of MOD-016-1 is to ensure that past and forecasted demand data is available for validation of past events and future system assessments. MOD-016-1 requires the planning authority and the regional reliability organization to have documentation identifying the scope and details of the actual and forecast demand and load data, and controllable DSM data to be reported for system modeling and reliability analysis.

1224. In the NOPR, the Commission proposed to approve Reliability Standard MOD-016-1 as mandatory and enforceable. In addition, the Commission proposed to direct NERC to submit a modification to MOD-016-1 that expands the applicability section to include the transmission planner.

i. <u>Comments</u>

1225. APPA agrees that MOD-016-1 is sufficient for approval as a mandatory and enforceable reliability standard.

1226. In contrast, ISO/RTO Council and ISO-NE do not support adoption of this standard because it is contingent on standards that are pending approval by the Commission based on their characterization as applying only to regional reliability organizations, or because they have been categorized as fill-in-the-blank standards.[358] ISO/RTO Council and ISO-NE agree that as a result, MOD-016-1 cannot be effectively implemented.

1227. APPA and FirstEnergy agree with the Commission's proposal to direct NERC to add the transmission planner function to the applicability section of the standard, although they argue that NERC, as the standards-setting entity, should make the decision.

1228. TAPS does not oppose the proposed applicability of MOD-016-1, but opposes regional interpretations that apply the standard more broadly. TAPS criticizes SERC's supplement to MOD-016-1 that makes the standard applicable to LSEs, even though LSEs do not have the ability to identify the scope and details of the data required to be reported for system modeling and reliability analyses. TAPS contends that there are no physical differences that make SERC LSEs more capable in this regard than LSEs in other regions. TAPS recommends that the Commission clarify that it expects standards to be applied in a consistent and uniform manner as written, and will look closely at regional variations not justified by physical differences.

1229. In contrast to APPA, FirstEnergy and TAPS, EEI believes that the standard assigns appropriate responsibility, and that the transmission planner should not be added to the applicability section of this standard. According to EEI, the transmission planner

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[358] TPL-005-0, TPL-006-0, MOD-011-0, MOD-013-0, MOD-014-0 and MOD-015-0.

has no specific responsibilities for ensuring data integrity in day-to-day practice. EEI understands that data integrity falls within the daily responsibilities of data management functions, such as metering. EEI states that the NERC Functional Model does not describe technical functions at this level of detail. EEI notes, as it also notes in its comments on the TPL standards, that load-related DSM data of the type and specificity stated in the NOPR, such as load control of customer-owned appliances, is related to distribution system and operations planning, and not to transmission system planning.

ii. Commission Determination

1230. The Commission approves MOD-016-1 as mandatory and enforceable. In addition, the Commission directs the ERO to modify MOD-016-1 as discussed below.

1231. As an initial matter, we disagree that MOD-016-1 cannot be implemented until other unapproved standards are modified. As previously stated, we are requiring the ERO to provide a Work Plan and compliance filing regarding collection of information specified under standards that are deferred, and believe there should be no difficulties complying with this Reliability Standard. We reiterate that continual collection of data is necessary to maintain system reliability, and approval of MOD-016-1 will help to achieve this objective.

1232. Supported by many commenters, the Commission directs the ERO to modify MOD-016-1 and expand the applicability section to include the transmission planner, on the basis that under the NERC Functional Model the transmission planner is responsible for collecting system modeling data, including actual and forecast load, to evaluate transmission expansion plans. We disagree with EEI that this Reliability Standard should not be applied to the transmission planner because load-related data for controllable DSM is not only needed for distribution and transmission operations, but is also necessary for the transmission planner to take controllable DSM into account in planning the transmission system. Requirement R1.1 relates to data submittal, and requires data to be consistent with that supplied for the TPL-005 and TPL-006 standards, which clearly apply to transmission planners. We approve the ERO's definition in the glossary of DSM as "all activities or programs undertaken by a Load-Serving Entity or its customers to influence the amount or timing of electricity they use." Only activities or programs that meet the ERO definition, with the modification directed below, may be treated as DSM for purposes of the Reliability Standards. Recognizing the potential role that industrial customers who do not take service through an LSE and load aggregators, for example, may play in meeting the Reliability Standards, we direct the ERO to modify the definition of DSM. Specifically, we direct the ERO to add to its definition of DSM "any other entities" that undertake activities or programs to influence the amount or timing of electricity they use without violating other Reliability Standard Requirement.

1233. In response to TAPS's criticism of SERC's desire to expand its regional standards relative to actual and forecast load to include LSEs, we clarify that we can only act on the standards before us. We do not make a decision on SERC's standards in this rule. We therefore recommend that TAPS raise this issue in the Reliability Standards development process.

1234. The Commission approves Reliability Standard MOD-016-1 as mandatory and enforceable and directs the ERO to develop a modification to MOD-016-0 through the Reliability Standards development process to include the transmission planner in the applicability section.

s. Aggregated Actual and Forecast Demands and Net Energy for Load (MOD-017-0)

1235. The purpose of MOD-017-0 is to ensure that past and forecasted demand data is available for past event validation and future system assessment. MOD-017-0 requires LSEs, planning authorities and resource planners to annually provide aggregated information on: (1) integrated hourly demands; (2) actual monthly and annual peak demand (MW) and net load energy (GWh) for the prior year; (3) monthly peak demand forecasts and net load energy for the next two years and (4) annual peak demand forecasts (summer and winter) and annual net load energy for at least five and up to ten years into the future.

1236. In the NOPR, the Commission proposed to approve Reliability Standard MOD-017-0 as mandatory and enforceable. In addition, the Commission proposed to direct NERC to submit a modification to MOD-017-0 that includes new requirements for: (1) reporting of temperature and humidity along with peak loads and (2) reporting of the accuracy, error and bias of load forecasts compared to actual loads while taking temperature and humidity variations into account.

i. Comments

1237. APPA agrees that the Commission should approve MOD-017-0 as mandatory and enforceable.

1238. In contrast to APPA, ISO-NE does not support approval of this standard because MOD-017-0 depends on MOD-016-0, which further depends on various unapproved standards. ISO-NE believes that this makes MOD-017-0 dependent on unapproved standards, and that consequently, MOD-017-0 cannot be effectively implemented. Similarly, ISO/RTO Council states that if the Commission does not approve MOD-016-0, then MOD-017-0 will refer to an unapproved standard.

1239. Although MidAmerican does not oppose the Commission's proposal regarding reporting of temperature and humidity along with peak loads, it finds it of only limited value. MidAmerican notes that there are typically other explanatory variables, such as economic variables, that are needed to understand the relationship between system load and temperature and humidity. In addition, the relationship and the importance of temperatures are different for every utility, which limits the effectiveness of standardization. FirstEnergy suggests that NERC should allow for a transition period for entities that currently do not track temperature and humidity along with peak load.

1240. Xcel states that in many areas of the country, humidity is not a weather-indicator for peak load. Xcel therefore suggests that instead of including a reporting requirement for humidity, the standard be revised to include a more generic term, such as "peak producing weather conditions." Alcoa requests that the Commission clarify that these requirements would only apply to load that varies with temperature and humidity.[359]

1241. Regarding the Commission's proposal for reporting of the accuracy, error and bias of load forecasts compared to actual loads while taking temperature and humidity variations into account, APPA disagrees that the Commission should direct NERC to modify MOD-017-0 to include these requirements. APPA argues that requiring the type and granularity of forecast information and data the Commission proposes would not necessarily increase the reliability of load forecasts. APPA believes that it should be up to NERC, as the expert standards-setting entity, to decide whether such information would yield enough useful data to make it worth mandating.

1242. TAPS is concerned that the NOPR's recommendation for reporting the accuracy, error and bias of load forecasts compared to actual loads may be interpreted to mean that measuring compliance is a function of forecast accuracy. TAPS contends that reliance on percentage-based deviations as a measurement of compliance is inappropriate when applied to very small entities because an error that in absolute terms is too small to affect the Bulk-Power System might be a significant percentage of the entity's load.

1243. EEI notes that the direction of the NOPR proposal seems to suggest an expansion of the current reporting processes required under the Energy Information Administration section 411 process. EEI suggests that such a proposal should consider whether the section 411 process itself requires change or provides for an adequate level of reporting,

[359] Alcoa states that because its smelting load (the vast majority of its load) does not vary in accordance with temperature and humidity, comparing Alcoa's load forecasts to actual loads taking this information into account would be burdensome without being useful.

and the extent to which an explicit NERC process requirement could distract or confuse industry participants.

1244. FirstEnergy states that the transmission planner should be added to the list of applicable entities for this standard. FirstEnergy also states that it may be reasonable to interpret or apply this Reliability Standard in a manner to permit an affected entity that is a subsidiary in a utility holding company corporate structure to satisfy its reporting requirements by means of a corporate affiliate. Adopting this interpretation or application would promote efficiency and decrease confusion in circumstances where several utility subsidiaries in the same corporate family are subject to this Reliability Standard.

1245. MISO recommends that the Commission direct NERC to change the requirement of this standard so that aggregated actual hourly demand data (at the balancing authority level) are to be provided within 30 calendar days of a request from NERC. MISO believes that load aggregated at this level should be sufficient for the modeling activities associated with system reliability. MISO understands that hourly data is collected by those utilities that have balancing authority responsibilities, and that these utilities can report aggregated hourly loads for their responsibility area within 30 days. MISO notes that some balancing authority utilities provide energy services to smaller municipal or distribution cooperative utilities where the metering system records only the peak demand and total energy supplied over approximately 30 days. MISO cautions that the balancing authority will usually have hourly data for demand and energy within a segment of the network, but may have no hourly metering on a specific customer served by that segment.

ii. Commission Determination

1246. The Commission approves MOD-017-0 as mandatory and enforceable. In addition, the Commission directs the ERO to modify MOD-017-0 as discussed below.

1247. As an initial matter, we disagree that MOD-017-0 cannot be implemented because it is dependent on MOD-016-0, which further depends on various unapproved standards. As previously stated, we direct the ERO to provide a Work Plan and compliance filing regarding the collection of information specified under standards that are deferred, and believe there should be no difficulty complying with this Reliability Standard. We reiterate that ongoing collection of data is necessary to maintain system reliability, and approval of MOD-017-0 will help achieve this goal.

1248. As a general matter, the Commission is required to insure that the Reliability Standards are sufficient to adequately protect Bulk-Power System reliability.[360] One of the main drivers in achieving Reliable Operation is to accurately predict the firm transactions and native load that must be served. Understanding the accuracy, error and bias of the forecast and taking action to minimize them would improve the Reliability Standards and achieve the goal.

1249. The Commission also directs the ERO to modify the Reliability Standad to require reporting of temperature and humidity along with peak load because actual load must be weather normalized for meaningful comparison with forecasted values.[361] In response to MidAmerican's observation that it sees little value in collecting this data, we believe that collecting it will allow all load data to be weather-normalized, which will provide greater confidence when comparing data accuracy, which ultimately will enhance reliability. As a result, we reject Xcel's proposal that the standard be revised to include only the generic term "peak producing weather conditions" because it is too generic for a mandatory Reliability Standard.

1250. We also reject Alcoa's proposal that the reporting of temperature and humidity along with peak loads should apply only to load that varies with temperature and humidity because it essentially is a request for an exemption from the requirements of the Reliability Standard and should therefore be directed to the ERO as part of the Reliability Standards development process. We agree, however, with APPA that certain types of load are not sensitive to temperature and humidity. We therefore find that the ERO should address Alcoa's concerns in its Reliability Standards development process.

1251. The Commission adopts the NOPR proposal directing the ERO to modify the Reliability Standard to require reporting of the accuracy, error and bias of load forecasts compared to actual loads with due regard to temperature and humidity variations. This requirement will measure the closeness of the load forecast to the actual value. We understand that load forecasting is a primary factor in achieving Reliable Operation. Underestimating load growth can result in insufficient or inadequate generation and transmission facilities, causing unreliability in real-time operations. Measuring the accuracy, error and bias of load forecasts is important information for system planners to include in their studies, and also improves load forecasts themselves.

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[360] Order No. 672 at P 329.

[361] See Brattle Group Report on PJM Load Forecast Model, available at http://www.pjm.com/planning/res-adequacy/load-forecast.html.

1252. The Commission agrees with APPA that accuracy, error and bias of load forecasts alone will not increase the reliability of load forecasts, and, as a result, will not affect system reliability. Understanding of the differences without action based on that understanding would not change anything. Therefore, we direct the ERO to add a Requirement that addresses correcting forecasts based on prior inaccuracies, errors and bias.

1253. Regarding TAPS's concern that accuracy of reporting may be used as a compliance Measure, we clarify that the compliance Measures for this Reliability Standard do not measure accuracy as a compliance Measure. Any change in the Measures would be arrived at in the Reliability Standards development process.

1254. The Commission acknowledges EEI's concern that a requirement for additional information may impose an expansion of existing Energy Information Administration section 411 reporting requirements.[362] We believe, however, that the ERO can ensure that the additional reporting of temperature and humidity along with peak loads does not conflict with or jeopardize the Energy Information Administration section 411 reporting process.

1255. We agree with FirstEnergy that transmission planners should be added as reporting entities, and direct the ERO to modify the standard accordingly. We agree that in the NERC Functional Model, the transmission planner is responsible for collecting system modeling data including actual and forecast demands to evaluate transmission expansion plans.

1256. The Commission disagrees in general with MISO's recommendation to allow some exceptions to the requirement to provide hourly demand data. However, the metering for some customer classes may not be designed to provide certain types of data. The Commission therefore directs the ERO to consider MISO's concerns in the Reliability Standards development process.

1257. The Commission approves Reliability Standard MOD-017-0 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification to MOD-017-0 through the Reliability Standards development process that includes requirements for: (1) reporting of temperature and humidity along with the peak loads;

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[362] Form EIA-411, "Coordinated Bulk Power Supply Program Report" collects information about regional electric supply and demand projections for a five-year advance period as well as information on the transmission system and supporting facilities. See http://www.eia.doe.gov/cneaf/electricity/page/forms.html.

(2) reporting of accuracy, error and bias of load forecasts compared to actual loads taking temperature and humidity variations into account; (3) addressing methods to correct forecasts to minimize prior inaccuracies, errors and bias and (4) including the transmission planner in the applicability section.

t. Treatment of Nonmember Demand Data and Uncertainties in the Forecasts of Demand and Energy for Load (MOD-018-0)

1258. The purpose of MOD-018-0 is to ensure that past and forecasted demand data are available for past event validation and future system assessment. MOD-018-0 requires LSEs, planning authorities, transmission planners and resource planners to submit load data reports that: (1) indicate whether the demand data includes the regional reliability organization's non-members' demands and (2) addresses how assumptions, methods and uncertainties are treated.

1259. In the NOPR, the Commission proposed to approve MOD-018-0 as mandatory and enforceable.

i. Comments

1260. APPA agrees that MOD-018-0 is sufficient for approval as a mandatory and enforceable reliability standard.

1261. In contrast to APPA, ISO/RTO Council and ISO-NE view MOD-018-0 as dependent upon fill-in-the-blank NERC standards, and as such, argue that the Commission should refrain from approving the Reliability Standard at this time. ISO-NE states that approval of this standard would create dependency of MOD-018-0 on other unapproved standards. Consequently, ISO-NE contends that MOD-018-0 cannot be effectively implemented.

1262. TAPS reiterates a similar concern it expressed with regard to MOD-017-0. TAPS notes that uncertainty in a small entity's forecast is insignificant. TAPS recommends that load forecast uncertainty should be addressed at an aggregate level on a regional basis (as is often done in the establishment of reserve obligations).

ii. Commission Determination

1263. The Commission approves MOD-018-0 as mandatory and enforceable.

1264. As an initial matter, we disagree that MOD-018-0 cannot be implemented because it is dependent on various unapproved standards. As previously stated, we direct the

ERO to provide a Work Plan and compliance filing regarding the collection of information specified for standards that are deferred, and believe there should be no difficulties complying with this Reliability Standard. We reiterate that ongoing collection of data is necessary to maintain system reliability, and approval of MOD-018-0 will help to achieve this goal.

1265. Regarding TAPS's concern that small entities should not be required to comply with MOD-018-0 because their forecasts are not significant for system reliability purposes, the Commission directs the ERO to address this matter in the Reliability Standards development process.

u. Reporting of Interruptible Demands and Direct Control Load Management (MOD-019-0)

1266. The purpose of MOD-019-0 is to ensure that past and forecasted demand data is available for past event validation and future system assessment. The Reliability Standard requires that LSEs, planning authorities, transmission planners and resource planners annually provide their forecasts of interruptible demands and direct control load management to NERC, the regional reliability organization and other entities as specified in MOD-016-1, Requirement R1. The data should contain the forecasts for at least five years, and up to ten years.

1267. In the NOPR, the Commission proposed to approve Reliability Standard MOD-019-0 as mandatory and enforceable. In addition, the Commission proposed to direct NERC to submit a modification to MOD-019-0 that includes new requirements for reporting of the accuracy, error and bias of controllable load[363] forecasts.

i. Comments

1268. APPA agrees that MOD-019-0 should be approved as mandatory and enforceable. However, APPA states that the proper entity to decide whether the recommended changes to the standards should be made is NERC, through Reliability Standards development process.

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[363] While MOD-019-0 and MOD-020-0 use two separate terms, interruptible load and direct control load management, the NOPR uses "controllable load" to refer to both of them.

1269. The ISO/RTO Council and ISO-NE note that MOD-019-0 is dependent, through MOD-016, on various unapproved standards. Consequently, they contend that MOD-019-0 cannot be effectively implemented.

1270. APPA proposes that NERC consider modifying MOD-019-0 to include new requirements for reporting on the accuracy, error and bias of controllable load forecasts. APPA further believes that NERC should consider adding requirements that would require resource planners to analyze differences between actual and forecasted demands for the five years of actual controllable load required in MOD-019-0 and identify what corrective actions were taken to improve controllable load forecasting for the 10-year planning horizon.

1271. EEI and FirstEnergy state that determining the precise availability and capability of direct load control is a difficult management and customer relations exercise, and therefore, this requirement should not be included in the Reliability Standard. EEI states that, unlike other technical requirements for generation resources to be tested for various capabilities and limits under different types of stresses, there are no similar requirements for load control equipment. Elsewhere in these comments, EEI supports explicit recognition that load control should be recognized on the same terms as generation resources for setting reserve requirements. However, EEI cautions against imposing requirements to verify load control devices and interruptible loads, because the practical complexities of conducting such testing and verification, including customer notification, the need to plan, manage, and coordinate testing with critical commercial and industrial customer activities, and the need to conduct such tests at times of peak load, make this an extremely difficult operational challenge.

1272. International Transmission notes that many load control applications are not individually metered, which means impact can only be estimated within a LSE's service territory. International Transmission believes that accurate reporting may not be feasible.

1273. TAPS raises concern that the Commission's recommendation in the NOPR may be interpreted to make forecast accuracy a component of Reliability Standards compliance. TAPS cautions that reliance on percentage-based deviations as a measurement of compliance is inappropriate when applied to very small entities because an error that in absolute terms is too small to affect the Bulk-Power System might be a significant percentage of the entity's load. The percentage deviation from a forecasted peak of a small (e.g., 10 MW) entity will almost always be significantly higher than the percentage deviation of a large (more than 10,000 MW) entity, but the smaller system's deviation will have little if any impact on the bulk transmission system. In other contexts, the Commission has recognized that reliance solely on percentage deviations as compliance measures can produce discriminatory results, and has applied MW minimums to minimize the discrimination that would otherwise result.

ii. Commission Determination

1274. The Commission approves MOD-019-0 as mandatory and enforceable. In addition, the Commission directs the ERO to modify MOD-019-0 as discussed below.

1275. As an initial matter, we disagree that MOD-019-0 cannot be implemented because it is dependent on MOD-016-0, which further depends on various unapproved standards. As previously stated, we direct the ERO to provide a Work Plan and compliance filing regarding the collection of information specified under related standards that are deferred, and believe there should be no difficulties complying with this Reliability Standard. We reiterate that ongoing collection of data is necessary to maintain system reliability, and approval of MOD-019-0 will help to achieve this goal. We therefore direct the ERO to use its authority pursuant to § 39.2(d) of our regulations to require users, owners and operators to provide to the Regional Entity information related to forecasts of interruptible demands and direct control load management.

1276. The Commission adopts the NOPR proposal directing the ERO to modify this standard to require reporting of the accuracy, error and bias of controllable load forecasts. This requirement will enable planners to get a more reliable picture of the amount of controllable load that is actually available, therefore allowing planners to conduct more accurate system reliability assessments. The Commission finds that controllable load can be as reliable as other resources, and therefore should also be subject to the same reporting requirements. Although we recognize that verifying load control devices and interruptible loads may be complex, we do not believe that it is overly so. Further, we believe that the ERO, through its Reliability Standards development process can develop innovative solutions to the Commission's concern. We also note that EEI is concerned about such testing at times of peak load. We clarify that we are not requiring the testing to be conducted at peak load conditions. Consequently, we reject the proposals of EEI, FirstEnergy and International Transmission to discard the requirement for reporting of the accuracy, error and bias of controllable load forecasts.

1277. We direct the ERO to include APPA's proposal in the Reliability Standards development process to add a new requirement to MOD-019-0 that would oblige resource planners to analyze differences between actual and forecasted demands for the five years of actual controllable load and identify what corrective actions should be taken to improve controllable load forecasting for the 10-year planning horizon.

1278. Regarding TAPS' concern that reporting accuracy could be used as a compliance Measure, we clarify that compliance Measures for this Reliability Standard do not include accuracy as a compliance measure. Any change in this policy would be arrived at in the ERO Reliability Standards development process.

1279. Accordingly, the Commission approves MOD-019-0 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification to MOD-019-0 through the Reliability Standards development process to require: (1) reporting of the accuracy, error and bias of controllable load forecasts and (2) analyzing differences between actual and forecasted demands for the five years of actual controllable load and identify what corrective actions should be taken to improve controllable load forecasting for the 10-year planning horizon.

v. Providing Interruptible Demand and Direct Control Load Management Data to System Operators and Reliability Coordinators (MOD-020-0)

1280. The purpose of MOD-020-0 is to ensure that past and forecasted demand data are available for validation of past events and future system assessment. The Reliability Standard requires that each LSE, planning authority, transmission planner and resource planner identify its amount of: (1) interruptible demand and (2) direct control load management to transmission operators, balancing authorities and reliability coordinators upon request.

1281. In the NOPR, the Commission proposed to approve Reliability Standard MOD-020-0 as mandatory and enforceable. In addition, the Commission proposed to direct NERC to submit a modification to MOD-020-0 that includes a new requirement concerning the reporting of the accuracy, error and bias of controllable load forecasts in its Reliability Standards development process.

i. Comments

1282. APPA supports approval of MOD-020-0 as mandatory and enforceable, as proposed by the Commission. APPA does not oppose NERC's consideration of possible changes to MOD-020-0 regarding the reporting of the accuracy, error and bias of controllable load forecasts.

1283. EEI and FirstEnergy state that for practical reasons, determining the precise availability and capability of direct load control is a difficult management and customer relations exercise. Unlike other technical requirements for generation resources to be tested for various capabilities and limits under different types of stresses, there are no similar requirements for load control equipment. The practical complexities of conducting such testing and verification, including customer notification, the need to plan, manage and coordinate testing with critical commercial and industrial customer activities, and the need to conduct such tests at times of peak load make this an extremely difficult operational challenge.

1284. LPPC opposes the Commission's proposal for modification to report the accuracy of load forecasts. LPPC points out that load reduction forecasts are imprecise by nature, and, consequently, some utilities do not undertake them. LPPC also notes that interruptible loads are often on one-year contracts and, in some regions, instances of entities actually exercising load reduction are rare; in these areas, system operators often do not separately forecast interruptible load reductions, and reporting on the accuracy of forecasts on interruptible load reductions, even if interruptible load forecasts were done, is of little value. LPPC states that in other areas, such as New York, interruptible load reductions are more predictable, because many large loads have signed interruptible load contracts and have a history of exercising load reductions. LPPC notes that system operators in areas similar to New York have sufficient data so that forecasting for interruptible loads is a useful exercise, and as a result, a requirement to report on the accuracy of forecasts in these regions would be of some value, but not elsewhere. Consequently, LPPC recommends that the requirement should be region-specific and should only apply to entities that separately forecast interruptible loads. LPPC further notes that energy efficiency programs are often built into the larger assumptions in the forecast and are not separately forecasted.

1285. TAPS is concerned that the Commission's recommendation in the NOPR may be interpreted to make forecast accuracy a component of Reliability Standards compliance. However, it asserts that reliance on percentage-based deviations as a measurement of compliance is inappropriate when applied to very small entities because an error that in absolute terms is too small to affect the Bulk-Power System might be a significant percentage of the entity's load. The percentage deviation from a forecasted peak of a small (e.g., 10 MW) entity will almost always be significantly higher than the percentage deviation of a large (more than 10,000 MW) entity, but the smaller system's deviation will have little if any impact on the bulk transmission system. In other contexts, the Commission has recognized that reliance solely on percentage deviations as a compliance measure can produce discriminatory results, and has applied MW minimums to minimize the discrimination that would otherwise result.

ii. Commission Determination

1286. The Commission approves MOD-020-0 as mandatory and enforceable. In addition, the Commission directs the ERO to modify MOD-020-0 as discussed below.

1287. We adopt the proposal to direct the addition of a requirement for reporting of the accuracy, error and bias of controllable load forecasts because we believe that reporting of this information will provide applicable entities with advanced knowledge about the exact amount of available controllable load, which will improve the accuracy of system reliability assessments. The Commission finds that controllable load in some cases may be as reliable as other resources and therefore must also be subject to the same reporting requirements. We recognize that determining the precise availability and capability of direct load control is a difficult management and customer relations exercise, but we do not believe that it will be overly so. Further, we believe that the ERO, through its Reliability Standards development process can develop innovative solutions to the Commission's concern. Regarding LPPC's suggestion that this requirement should be region-specific and should only apply to entities that separately forecast interruptible loads, we note that if a region does not forecast interruptible loads, this Reliability Standard does not apply.

1288. Regarding TAPS' concern that forecast accuracy may be interpreted as a component of Reliability Standards compliance, we clarify that compliance Measures for this Reliability Standard do not measure accuracy as a compliance measure. Any change in this policy would be arrived at in the ERO Reliability Standards development process.

1289. The Commission approves Reliability Standard MOD-020-0 as mandatory and enforceable and directs the ERO to develop a modification to MOD-020-0 through the Reliability Standards development process to require reporting of the accuracy, error and bias of controllable load forecasts.

w. Documentation of the Accounting Methodology for the Effects of Controllable Demand-Side Management in Demand and Energy Forecasts (MOD-021-0)

1290. MOD-021-0 requires LSEs, transmission planners and resource planners to clearly document how each addresses the demand and energy effects of DSM programs. The standard also requires an applicable entity to include information detailing how DSM measures are addressed in the forecasts of its peak demand and annual net energy for load in the data reporting procedures of MOD-016-0, Requirement R1.

1291. In the NOPR, the Commission proposed to approve Reliability Standard MOD-021-0 as mandatory and enforceable. In addition, the Commission proposed to direct NERC to submit a modification to MOD-021-0 that: (1) includes a requirement standardizing principles on reporting and validation of DSM program information and (2) modifies the title and purpose statement to remove the word "controllable."

i. Comments

1292. APPA supports the Commission's the approval of MOD-021-0 as mandatory and enforceable.

1293. In contrast, ISO-NE and ISO/RTO Council oppose adoption of this standard by the Commission. ISO-NE argues that the LSE, transmission planner and resource planner should each include information regarding how DSM measures are addressed in the forecasts of its peak demand and annual net energy for load in the data reporting procedures of MOD-016-0 R1. Therefore, they contend that, because MOD-016-0 is dependent on various unapproved Reliability Standards, MOD-021-0 is also dependent on unapproved Reliability Standards. Consequently, ISO-NE contends that MOD-021-0 cannot be effectively implemented.

1294. FirstEnergy and SMA support the Commission's proposal to require consistent and uniform methods for reporting and validating demand-side information. SMA notes that this will provide more consistent and uniform evaluation of demand response data to facilitate system operator confidence in relying on such resources for various reliability purposes. In addition, APPA believes that NERC should consider adding requirements to MOD-021-0 that would provide information to allow resource planners to analyze the causes of differences between actual and forecasted demands, and to identify any corrective actions that should be taken to improve forecasted demand responses for future forecasts. APPA believes that all of these proposals should be submitted to NERC as the standards-setting body with technical expertise, and vetted through its Reliability Standards development process, rather than being imposed by Commission fiat.

1295. FirstEnergy adds that MOD-019-0, MOD-020-0 and MOD-021-0 should be combined because they all address load forecast inputs, and that combining these standards will eliminate any inconsistencies and make compliance easier and more efficient.

ii. Commission Determination

1296. The Commission approves MOD-021-0 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification to MOD-021-0 through the Reliability Standards development process as discussed below.

1297. As an initial matter, we disagree that MOD-021-0 cannot be implemented because it is based on MOD-016-0, and through it on various unapproved standards, which creates an implementation problem. As previously stated, we direct the ERO to provide a Work Plan and compliance filing regarding collection of information specified under related standards that are deferred, and believe there should be no difficulty complying with this Reliability Standard. We reiterate that ongoing collection of data is necessary to maintain system reliability, and approval of MOD-21-0 will help to achieve this goal. Therefore, we direct the ERO to use its authority pursuant to § 39.2(d) of our regulations to require users, owners and operators to provide to the Regional Entity the information required by this Reliability Standard.

1298. We agree with FirstEnergy and SMA that standardization of principles on reporting and validating DSM program information will provide consistent and uniform evaluation of demand response to facilitate system operator confidence in relying on such resources, which will further increase accuracy of transmission system reliability assessment and consequently enhance overall reliability. We direct the ERO to modify this Reliability Standard to allow resource planners to analyze the causes of differences between actual and forecasted demands, and to identify any corrective actions that should be taken to improve forecasted demand responses for future forecasts. Therefore, we adopt the NOPR proposal and direct the ERO to modify MOD-021-0 by adding a requirement for standardization of principles on reporting and validating DSM program information.

1299. With respect to FirstEnergy's suggestion to combine MOD-019-0, MOD-020-0 and MOD-021-0, we understand that the ERO intends to consolidate Reliability Standards and encourage FirstEnergy to make its suggestion in the Reliability Standards development process.

1300. The Commission directs the ERO to modify the title and purpose statement to remove the word "controllable." We note that no commenter disagrees.

1301. The Commission approves Reliability Standard MOD-021-0 as mandatory and enforceable. We direct the ERO to develop a modification to MOD-021-0 through the Reliability Standards development process to (1) add a Requirement standardizing principles on reporting and validation of DSM program information; (2) allow resource planners to analyze the causes of differences between actual and forecasted demands, and to identify any corrective actions that should be taken to improve forecasted demand responses for future forecasts and (3) modify the title and purpose statement to remove the word "controllable."

x. Verification of Generator Gross and Net Real Power Capability (MOD-024-1)

1302. The purpose of MOD-024-1 is to ensure that accurate information on generation gross and net real power capability is used for reliability assessments. The Reliability Standard requires the regional reliability organization to establish and maintain procedures to address verification of generator gross and net real power capability. It also requires a generator owner to follow its regional reliability organization's procedure for verifying and reporting gross and net real power generating capability.

1303. In the NOPR, the Commission identified MOD-024-1 as a fill-in-the-blank standard that requires the regional reliability organization to establish and maintain procedures to address verification of generator gross and net real power capability. The

Commission stated that because the regional procedures had not been submitted, it would not propose to approve or remand MOD-024-1 until the ERO submits the additional information. In addition, the Commission expressed concern that the Reliability Standard is not sufficiently clear because it does not define test conditions, e.g., ambient temperature, river water temperature or methodologies for calculating de-rating factors for conditions such as higher ambient temperatures than the test temperature. Further, the NOPR stated that Requirement R2 provides that the "regional reliability organization shall provide generator gross and net real power capability verification within 30 calendar days of approval" and noted that it is not clear what approval is required and when the 30-day period starts.

i. Comments

1304. APPA agrees that MOD-024-1 is a fill-in-the-blank standard, is not sufficient as currently drafted, and should not be approved as a mandatory Reliability Standard until NERC and the regional reliability organizations/Regional Entities develop the necessary regional methodologies and the Commission approves them.

1305. APPA also states that the results of field-testing will enable NERC to refine this Reliability Standard in an appropriate manner. APPA further believes that NERC should consider modifying this Reliability Standard to provide requirements for this information on an Interconnection-wide basis, in the same manner that IRO-006-2 sets the requirement for transmission loading relief in each Interconnection.

1306. Northern Indiana urges the Commission to reconsider the proposed changes at this time in favor of continuation of the currently-effective Reliability Standard. Northern Indiana states that the NOPR's suggestion that there should be greater specificity and definition of test conditions could potentially create reliability issues, rather than protect against them. Northern Indiana explains that certain types of testing, and their preparation, can be accomplished more quickly than others, with test duration varying from several minutes to several days.[364] The problem is compounded if a test takes some

[364] Northern Indiana states that the longer the duration, the more stressed the units – and the system – during these testing intervals. For example, Commission staff recommends the use of ambient air temperature and river water temperature as triggering tests to verify generator gross and net real power capability. However, temperature-driven test triggers would result in several neighboring systems in the same region undergoing tests at the same time in order to meet the test criteria. For example, a temperature trigger of 90 degrees Fahrenheit for a net demonstrated capacity test could result in all neighboring generating owners taking their units off of automatic generator

(continued)

time to complete, and all neighboring generating owners were required to comply at the same time. The end result would be a lack of regulating capability in a region.

1307. Constellation encourages the Commission and NERC to take extra care in distinguishing between those requirements in each Reliability Standard that are core requirements as opposed to supporting information, explanatory statements or administrative processes. For example, Constellation points out that in MOD-024-1, NERC proposes that a verification process be made into a Reliability Standard with full enforceability. Although Constellation agrees that the verification process spelled out in this Reliability Standard is important and should be performed by the industry, the Reliability Standard, alone, exclusively provides for an administrative process and, therefore, if not strictly complied with, does not necessarily foreshadow an immediate, real-time reliability problem on the bulk electric system. Constellation is concerned that the Levels of Non-Compliance associated with MOD-024-1 and MOD-025-1 are based on arbitrary percentages that have little to do with the impact a failure to perform would have on reliability. Constellation believes that these problems ultimately will reduce the effectiveness of the Reliability Standards. Consequently, Constellation requests that the Commission recognize these concerns and direct NERC to take them into consideration during the Reliability Standards development process.

ii. Commission Determination

1308. The Commission will not approve or remand MOD-024-1 until the ERO submits additional information. In order to continue verifying and reporting gross and net real power generating capability needed for reliability assessment and future plans, we direct the ERO to develop a Work Plan and submit a compliance filing.

1309. The Commission remains concerned that the Reliability Standard is not sufficiently clear because it does not define the test conditions and methodologies for calculating de-rating factors. The Commission does not agree with APPA that NERC should consider modifying this Reliability Standard to provide requirements for this information on an Interconnection-wide basis, in the same manner that IRO-006-3 sets the requirements for transmission loading relief in each Interconnection. We believe, however, that while the overall methodology for verification of generator gross and net real power capability should be the same, test conditions (such as ambient temperature, river water temperature, etc.) can vary.

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control to reach maximum net demonstrated capacity for the test. By taking units off automatic generator control, the generating owners' regulating capabilities are lost.

1310. In the NOPR, the Commission stated that the Reliability Standard could be improved by defining test conditions, e.g., ambient temperature, river water temperature, and methodologies for calculating de-rating factors for conditions such as higher ambient temperatures than the test temperature. With the test information and methodologies, the generator output that can be expected to be available at forecasted weather conditions can be determined. The Commission agrees with Northern Indiana that testing all units at the same time is not feasible. However, the Commission did not propose simultaneous testing. Rather, we direct the ERO to develop appropriate requirements to document test conditions and the relationships between test conditions and generator output so that the amount of power that can be expected to be delivered from a generator at different conditions, such as peak summer conditions, can be determined. Similarly, we respond to Constellation that any modification of the Levels of Non-Compliance in this Reliability Standard should be reviewed in the ERO Reliability Standards development process.

1311. We repeat our concern that Requirement R2, which specifies that the "regional reliability organization shall provide generator gross and net real power capability verification within 30 calendar days of approval," is not clear. The requirement lacks a definition of what approval is required and when the 30-day period starts. Therefore, we direct the ERO to modify this Reliability Standard by adding information that will clarify this requirement.

1312. The Commission neither accepts nor remands MOD-024-1 until the ERO submits additional information. Although the Commission did not propose any action with regard to MOD-024-1, it addressed above a number of concerns regarding the Reliability Standard. We therefore direct the ERO to use its authority pursuant to § 39.2(d) of our regulations to require users, owners and operators to provide this information. In the interim, compliance with MOD-024-0 should continue on a voluntary basis, and the Commission considers compliance with it to be a matter of good utility practice.

y. Verification of Generator Gross and Net Reactive Power Capability (MOD-025-1)

1313. MOD-025-1 requires the regional reliability organization to establish and maintain procedures to address verification of generator gross and net reactive power capability. The Reliability Standard also requires the regional reliability organization to provide its generator gross and net reactive power capability verification and reporting procedures, and any changes to those procedures, to the generator owners, generator operators, transmission operators, planning authorities and transmission planners affected by the procedure within 30 calendar days of approval of the Reliability Standard.

1314. In the NOPR, the Commission identified MOD-025-1 as a fill-in-the-blank standard that requires the regional reliability organization to establish and maintain procedures to address verification of generator gross and net reactive power capability. The NOPR stated that because the regional procedures had not been submitted, the Commission would not propose to approve or remand MOD-025-1 until the ERO submits the additional information. In addition, the Commission suggested that MOD-025-1 could be clearer by requiring a minimum reactive power (MVAR) capability throughout a unit's real power operating range. Further, the NOPR stated that requirement R2 provides that the "regional reliability organizations shall provide generator gross and net real power capability verification within 30 calendar days of approval" and noted that it is not clear what approval is required and when the 30-day period starts.

i. Comments

1315. APPA agrees that the Commission should not approve this Reliability Standard until NERC and the regional reliability organizations/Regional Entities develop the necessary regional methodologies and the Commission approves them.

1316. MidAmerican notes that the Reliability Standard will be clearer if minimum reactive power capability is required throughout a unit's real power operating range. However, making this a Requirement for existing units would be a hardship for units not built with the Requirement in mind. Therefore, MidAmerican suggests that any such requirement should allow existing units to be grandfathered in as they are currently rated so that a new minimum reactive power standard is only applicable to new generating units or units that are being significantly upgraded.

1317. Northern Indiana cautions the Commission against the establishment of a minimum capability, because it could diminish a unit's ability to contribute to Interconnection reliability, and to maintain its own stability. Northern Indiana points out that all generators have reactive capability curves from design manufacturers, and these curves provide operators with a range that is considered by the manufacturer to be a safe operating limit. Northern Indiana contends that the continued use of reactive capability curves is superior to establishment of an MVAR capability, and that operators effectively use these curves to maintain unit stability, while also contributing to the reliability of the Interconnection. Northern Indiana believes that continued reliance on manufacturer reactive capability curves is a technically sound means to achieve the Reliability Standard's stated reliability goal in a manner superior to the establishment of MVAR capability.

1318. Similarly to Northern Indiana, Wisconsin Electric encourages the Commission to withdraw this suggested modifications to NERC's Reliability Standard for several reasons. Wisconsin Electric believes that a requirement to test and verify the minimum reactive capability at multiple points over the operating range as part of the additional minimum MVAR capability requirement would be a significant and unnecessary burden on utilities. In Wisconsin Electric's experience, a reactive power test at a single operating point is sufficient and more practical to achieve.

1319. SoCal Edison recommends that the Commission specifically state the effective date for compliance with each Reliability Standard in its Final Rule. SoCal Edison states that the effective date is critical and gives the example of MOD-025-1, with effective dates phased in over several years after they are adopted by the NERC board of trustees, and well after the date the Final Rule will be issued.

ii. Commission Determination

1320. The Commission will not approve or remand MOD-025-1 until the ERO submits additional information. In order to continue verifying and reporting gross and net reactive power generating capability needed for reliability assessment and future plans, we direct the ERO to develop a Work Plan as defined in the Common Issues section.

1321. We disagree with commenters that verifying generator reactive capability is a particularly difficult issue. The capability of generators to produce reactive power is essential for real-time analysis and planning. The Reliability Standard addressing this issue requires a generator to verify reactive capability only at the unit's full MW loading. However, other than baseload units, most generating units rarely operate at full MW loading. It is unclear what reactive capability is available throughout a unit's real power (MW) operating range. Therefore, we believe a clearer standard would require a verification of MVAR capability throughout a unit's real power (MW) operating range. However, we share concern with several commenters that such a requirement for all generators may not be necessary. Therefore, we adjust the proposal in the NOPR and direct the ERO to modify MOD-025-1 to require verification of reactive power capability at multiple points over a unit's operating range.

1322. We maintain the concern we expressed in the NOPR that Requirement R2 provides that the "regional reliability organization shall provide generator gross and net reactive power capability verification within 30 calendar days of approval" and note that it is not clear what approval is required and when the 30-day period starts. We direct the ERO to provide clarification on this requirement.

1323. The Commission neither accepts nor remands MOD-025-1 until the ERO submits additional information. Although the Commission did not propose any action with regard to MOD-025-1, it addresses above a number of concerns regarding the Reliability Standard. We direct the ERO to develop a Work Plan to verify and report on generator gross and net reactive power capability while this Reliability Standard is being modified and to modify this Reliability Standard through the Reliability Standards development process to: (1) require verification of a reactive power capability at multiple points over a unit's operating range and (2) clarify Requirement R2 with a definition of what approval is needed and when the 30-day period starts.

9. PER: Personnel Performance, Training and Qualifications

1324. The four proposed Personnel Performance, Training and Qualifications (PER) Reliability Standards are applicable to transmission operators, reliability coordinators and balancing authorities with the intention of ensuring the safe and reliable operation of the interconnected grid through the retention of suitably trained and qualified personnel in positions that can impact the reliable operation of the Bulk-Power System. The PER Reliability Standards address: (1) operating personnel responsibility and authority; (2) operating personnel training; (3) operating personnel credentials and (4) reliability coordination staffing.

a. Operating Personnel Responsibility and Authority (PER-001-0)

1325. PER-001-0 requires that transmission operator and balancing authority personnel have the responsibility and authority to direct actions in real-time. PER-001-0 also requires clear documentation that operating personnel have the responsibility and authority to implement real-time action to ensure the stable and reliable operation of the Bulk-Power System.

1326. In the NOPR, the Commission proposed to approve PER-001-0 as mandatory and enforceable.

i. Comments

1327. APPA agrees that PER-001-0 is sufficient for approval as a mandatory and enforceable Reliability Standard.

1328. ISO-NE supports the adoption of this Reliability Standard provided that the Commission does not mandate that the tasks performed by local control centers be included in the definition of transmission operators. It explains that to do so would suggest that the local control center has independent autonomy in operating the Bulk-Power System, which conflicts with the "one set of hands on the wheel" philosophy supported by Order No. 2000 and the operating agreements approved by the Commission to establish ISO-NE as New England's RTO.

ii. Commission Determination

1329. The Commission agrees with the "one set of hands on the wheel" philosophy described by ISO-NE as it applies to operations of the Bulk-Power System and has no intention of deviating from it. Nothing in the Commission's proposed modifications outlined in the NOPR in regard to the PER Reliability Standards is intended to conflict with this philosophy. A generic discussion of the local control centers is included in the Applicability Issues section and specific implications to operator training are discussed in PER-002-0.[365]

1330. Accordingly, the Commission approves PER-001-0 as mandatory and enforceable. We find that the Reliability Standard is just, reasonable, not unduly discriminatory or preferential and in the public interest.

b. Operating Personnel Training (PER-002-0)

1331. PER-002-0 requires that transmission operator and balancing authority personnel are adequately trained. The Reliability Standard: (1) directs each transmission operator and balancing authority to have a training program for all operating personnel who occupy positions that either have primary responsibility, directly or indirectly, for the real-time operation of the Bulk-Power System or who are directly responsible for complying with the NERC Reliability Standards; (2) lists criteria that must be met by the training program and (3) requires that operating personnel receive at least five days of training in emergency operations each year using realistic simulations.

1332. In the NOPR, the Commission proposed to approve Reliability Standard PER-002-0 as mandatory and enforceable. In addition, the Commission proposed to direct that NERC submit a modification to PER-002-0 that: (1) identifies the expectations of the training for each job function; (2) develops training programs tailored to each job function with consideration of the individual training needs of the personnel; (3) expands the applicability to include reliability coordinators, generator operators, and operations planning and operations support staff with a direct impact on the reliable operation of the Bulk-Power System; (4) uses the Systematic Approach to Training (SAT) methodology in its development of new training programs and (5) includes performance metrics associated with the effectiveness of the training program. In addition, the Commission requested comments on the benefits and appropriateness of required "hands-on" training using simulators in dealing with system emergencies.

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[365] See Applicability Issues: Use of the NERC Functional Model, supra section II.C.4.

i. General Issues

(a) Comments

1333. EEI supports the Commission's direction for personnel training and generally agrees with the Commission's proposal for PER-002-0. EEI states NERC is developing a new Reliability Standard, PER-005-0, which could be filed with the Commission as early as July 2007. According to EEI, this new Reliability Standard will respond to the issues raised in the NOPR regarding PER-002-0. EEI notes that the ERO plans to retire Reliability Standards PER-002-0 and PER-004-1 when proposed PER-005-0 is adopted. It recommends that the Commission consider consolidating all training requirements into a single Reliability Standard to simplify the Reliability Standards catalog.

1334. Additional comments received have been grouped as follows: local control center personnel; applicability to generator operators; applicability to operations planning and operations support staff; implications to small systems; training performance metrics; use of SAT methodology; and use of simulators separately, followed by an overall conclusion and summary.

(b) Commission Determination

1335. EEI's comments concerning a possible PER-005-0 are beyond the scope of this proceeding. The Commission will not require the ERO to consolidate all training requirements into a single Reliability Standard. We believe that such matters should be left to the discretion of the ERO through its Reliability Standards development process.

ii. Local Control Center Personnel

1336. In the NOPR, the Commission noted that decision making and implementation may be performed by separate groups in an ISO or RTO context, as well as other organizations that pool resources.[366] The Commission proposed that all control centers and organizations that are necessary for the actual implementation of the decision or are needed for operation and maintenance made by the ISO, RTO or pooled resource organization should be part of the transmission or generator operator function. Although the NOPR discussed this matter in the context of the Communication (COM) Reliability

[366] NOPR at P 236-37.

Standards, the NOPR indicated that the proposal would apply in the training and certification context, as well.[367]

(a) Comments

1337. EEI states that the term "operating personnel" as used in the PER group of Reliability Standards needs clarification because it may be interpreted to mean any person with a capability to take a unilateral action that can have a potentially significant effect on the Bulk-Power System. EEI states that the term is open to broad interpretation in actual practice, subject to various contracts, operating agreements and ISO/RTO procedures. It states, for example, a local control center operator may take instructions from and act on those instructions, whereas the 'transmission operator' under the Functional Model may be viewed as a more centralized authority such as a larger regional system operator. EEI contends that some define local control center as a transmission operator, while others disagree.

1338. ISO-NE states the scope of PER-002-0 need not be expanded because local control center personnel in its footprint implement tasks delegated to them by ISO-NE for operation of designated transmission facilities. NPCC argues that expanding PER-002-0 beyond the entities identified under the NERC Functional Model (i.e., transmission operators, reliability coordinators and balancing authorities) will require substantial cost and time but add little value. It states that there are no certification exams for any entities other than transmission operators, reliability coordinators and balancing authorities and to develop and implement such exams and to have the additional personnel certified would take several years. It also states that these personnel already function under the authority of NERC-certified operators and act only at the direction of certified operators. It concludes that an entity that does not exercise operational authority should not be subject to the same requirements as the decisionmaker.

1339. Northern Indiana states that it is not uncommon in the industry for employees who perform switching operations to be supervised by NERC-certified operators and that such employees are subject to round-the-clock review by, and communication with, their NERC-certified transmission operators. Similarly, SoCal Edison notes that large utilities can have operators strategically located throughout a vast service territory at switching centers with SCADA capability and that these operators follow the directives of one control center responsible for Bulk-Power System reliability. SoCal Edison disagrees that the operators of these switching centers, simply because the switching center has SCADA capability, must be NERC-certified.

[367] Id. at P 237, 779.

1340. LPPC states that the training and certification requirements should apply only to transmission and generation personnel that are located in the transmission control center (i.e., responsible for real-time Bulk-Power System operations). It argues that transmission and generation operation employees that are located in remote locations that are not directly involved in the real-time scheduling of transactions or Bulk-Power System monitoring and control do not need to be certified for real-time operations because they are not involved in the type of functions in which regimented training in the Reliability Standards would be useful. It suggests that a bright line should be drawn between the training of actual system operators and the training for operators of generation plants that are not responsible for scheduling. LPPC also states that the Commission should clarify the scope of training that the transmission control center real-time operations personnel should receive.

1341. Entergy asserts that the training program should be tailored to the functions local control center operators, generator operators and operations planning staff perform that impact the reliable operation of the Bulk-Power System for both normal and emergency operations.

(b) Commission Determination

1342. In our discussion above regarding the Functional Model, we emphasized our concern that there should be no unintentional gaps or redundancies in responsibility for compliance with the Requirements of Reliability Standards. This concern arises particularly in the context of RTOs, ISOs and other pooled resources that may have separate divisions performing decisionmaking functions and implementing functions within the transmission operator classification. The topic of training is one such area of concern. While PER-002-0 applies to transmission operators, it is important for reliability that personnel involved in both decisionmaking and implementation receive proper training.

1343. Clearly, in a region where an RTO or ISO performs the transmission operator function, its personnel with primary responsibility for real-time operations must receive formal training pursuant to PER-002-0. In addition, personnel who are responsible for implementing instructions at a local control center also affect the reliability of the Bulk Power System. These entities may take independent action under certain circumstances, for example, to protect assets, personnel safety and during system restorations. Whether the RTO or the local control center is ultimately responsible for compliance is a separate issue addressed above, but regardless of which entity registers for that responsibility, these local control center employees must receive formal training consistent with their roles, responsibilities and tasks. Thus, while we direct the ERO to develop modifications to PER-002-0 to include formal training for local control center personnel, that training should be tailored to the needs of the positions.

1344. As noted by SoCal Edison, there are different operating structures and therefore there is a need to clarify to which control centers we direct the Reliability Standard apply. For example, for a large utility within an RTO or ISO footprint there may be one centrally-located control center whose function is to supervise several distributed control centers, each with remote monitoring and control capability. In this type of structure, the personnel of the centrally-located control center should receive formal training in accordance with the Reliability Standard. Personnel at the distributed control centers also need to be trained, but the responsibility for this training is outside the scope of the Reliability Standard.[368]

1345. Another organizational structure, typically representative of relatively smaller entities, consists of a single control center that implements operating instructions from its transmission operator, e.g., an RTO, ISO or pooled resource. Similar to the discussion above, operators at these control centers also may take independent action to protect assets, safety and system restoration. Such control center personnel must also receive formal training pursuant to PER-002-0.

1346. Consistent with the comments of SoCal Edison and Northern Indiana, the Commission understands that it is common practice to have traveling operators located in the local control centers who carry out field switching operations and station inspections at the direction of the local control center operators. These personnel are not involved with the transmission operator at the ISO or RTO or at organizations with pooled resources, and as such, should not be subject to Reliability Standard PER-002-0.

1347. The Commission disagrees with those commenters who contend that, because operators at local control centers take direction from NERC-certified operators at the ISO or RTO, they do not need to be addressed by the training requirements of PER-002-0. Rather, as discussed above, these operators maintain authority to act independently to carry out tasks that require real-time operation of the Bulk-Power System including protecting assets, protecting personnel safety, adhering to regulatory requirements and establishing stable islands during system restoration.

1348. Several commenters express concern about requiring local control center operators to become fully trained to the same extent as transmission operators, balancing authorities and reliability coordinators. This is not the Commission's intent. As we stated in the NOPR, the proposed modifications do not imply a "one-size-fits-all" approach but rather ensure the creation of training programs that are structured and

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[368] The Commission expects the entity registered as the transmission operator to ensure that these personnel are competent for the tasks that they perform.

tailored to the different functions and needs of the personnel involved.[369] Therefore the Commission agrees with Entergy that the training program should be tailored to the functions local control center operators, generator operators and operations planning staff perform that impact the reliable operation of the Bulk-Power System for both normal and emergency operations.

iii. Applicability to generator operators

1349. The Commission proposed in the NOPR a modification to PER-002-0 to include real-time operations personnel from reliability coordinators, generator operators, operations planning and operations support staff in training programs with a time-phased effective date.[370]

(a) Comments

1350. PG&E and FirstEnergy support the Commission's goal of ensuring appropriate training for generator operators. FirstEnergy, however, believes that there is some confusion between the Functional Model and the Reliability Standard requirements concerning the generator operator classification. FirstEnergy explains that, in some contexts, "generator operator" refers to operations personnel who are centrally-located at a generation control center (i.e., fleet operators) while in other contexts it refers to generator operators located at the generation plant (i.e., unit operator). Further, according to FirstEnergy, the NERC glossary defines "generator operator" as the entity that operates generating unit(s) and performs the functions of supplying energy and interconnected operations services. FirstEnergy requests that the Commission direct NERC to revise the Reliability Standard to recognize this distinction.

1351. Other commenters, including Xcel, California PUC and Entergy, state that the Reliability Standard should not apply to generator operators. Xcel argues that generator operators take their direction from transmission operators, balancing authorities and reliability coordinators, which limits their ability to exercise independent action impacting the reliability of the Bulk-Power System. Entergy argues that expanding the applicability to generator operators would provide little benefit to those personnel in the performance of their own functions, and could distract them from those functions. It also argues that such training would be extremely costly and would divert necessary resources from more important reliability objectives.

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[369] See NOPR at P 773, 775.

[370] Id. at P 772.

1352. California PUC states that the requirement to include power plant operators in the applicability of this Reliability Standard exceeds anything contemplated in the regulation of the Bulk-Power System under previous NERC guidelines and what is authorized by statute. It contends that impacts of generator operator actions on the Bulk-Power System are of a much smaller magnitude and consequence than those of system operators. Further, it states that other authorities, such as balancing authorities and state governments, may have acted in regard to training of power plant operators and, therefore, the Commission should not act where other authorities have already done so. In a similar vein, the Nevada Companies state that the activities of generating station operations personnel are limited to the confines of the specific generating station. Knowledge of or exposure to interconnected grid operating principles is simply not applicable to the tasks normally performed at the generating stations.

1353. Reliant states that the proposed modification fails to clarify how generator operators are to satisfy the training program requirement or the scope of generator operator personnel that must be trained. It states that the proposed modification could be interpreted to require generator operators to train the plant operator as well as the dispatcher in the generator operator's local control center. Reliant believes, however, that plant operators should not be subject to the Reliability Standard's training program requirement because personnel employed in plant operating positions are trained in the operation of plant equipment and take direction with respect to the operation of the plant from management personnel as well as from the local control center. Accordingly, it reasons that, because these employees take direction with respect to plant operations from elsewhere, they do not have primary responsibility for the real-time operation of the Bulk-Power System and should not be responsible for complying with Reliability Standards. Reliant suggests that PER-002-0 should specifically target generator operator personnel that develop dispatch instructions and the Reliability Standard should be modified to accommodate generator operator entities that are members of ISOs and RTOs with established NERC-approved certification programs. However, it should exclude those personnel who simply take direction on plant operations.

1354. Dynegy, MISO and Wisconsin Electric state that these Reliability Standards should not be extended to all real-time operation positions of a generator operator. They state that many real-time operation positions are staffed by long-tenured union personnel who routinely operate generating units and take directions from a centralized generation control center or the local RTO/ISO. They analogize this type of certification and training requirement with requiring the outside field force of a transmission operator, including positions that operate and switch electric transmission lines pursuant to instructions from a centralized transmission control group, to be NERC-certified. Dynegy and MISO support a more limited extension of these Reliability Standards to