Responses to comments submitted during the balloting of the Monitor and Assess short-term Transmission Reliability, Operate within Interconnection Reliability Operating Limits standard

The Operate within Limits Standard Drafting Team thanks all those who submitted comments with their ballots on the recent posting of this standard. After careful review and consideration of all comments received, the drafting team has modified the standard and is re-posting the standard for another 45-day comment period.

The SDT's most significant changes include the following:

- Clarified the definitions of 'widespread impact,' 'cascading outages' and 'bulk electric system' so they are measurable.
- Modified the definition of T_v to align its definition with interconnection risk rather than sanctions and to indicate that T_v can't exceed 30 minutes.
- Modified Requirement 201 for IROL Identification to better reflect the dynamic nature of IROLs
- Modified Requirement 201 to add language to ensure that RAs that share a Facility (or group of Facilities) have an agreed upon process for determining if the Facility is subject to IROLs and for developing the IROL and its T_v
- Modified Requirement 204 for RA Actions to indicate that the RA must act 'without delay' to prevent or mitigate instances of exceeding IROLs
- Modified the sanction associated with operating outside an IROL for time greater than T_v to make the sanction proportional to both the magnitude and the duration of the incident.

Changes outside the Scope of the SDT:

Several Balloters asked the SDT to make some changes that are outside the scope of the SDT. These changes include the following:

- Wait until the Functional Model is modified, re-approved and/or better understood
- Wait until related Standards are approved
- Wait until Field Testing is conducted
- Expand the scope to include operating outside all System Operating Limits – not just those that could cause instability, cascading outages or uncontrolled separation

Consideration of Comments:

The SDT provided a response to each comment that was submitted with a ballot. These comments can be reviewed at the following site:

http://www.nerc.com/~filez/standards/IROL.html

Detailed List of Topics Addressed in Comments

Definitions

Tv

T_v: The maximum time that an Interconnection Reliability Operating Limit can be exceeded ~~without compliance sanctions being applied~~ before the risk to the interconnection becomes greater than acceptable. T_v may not be greater than 30 minutes.

Summary Consideration:

Several balloters indicated a preference for a definition that references risk to the interconnection rather than compliance sanctions. In other comments, many balloters indicated a preference for setting a maximum value for Tv of 30 minutes. The definition has been revised as follows:

Entergy EES (Transmission Owners)

DEFINITION OF Tv - The Transmission Owner has fiduciary responsibility for his owned facilities. Therefore he has ultimate responsibility and liability for owning, maintaining and operating his facilities to protect his stockholders' and lending institutions' investments. The Transmission Owner then is ultimately responsible for establishing system operating limits, including Tv, for his facilities.

By definition, a system violating an IROL, and in the Tv period, is operating in a critical operating state and is probably violating equipment limits set by the Transmission Owner.

Also, the value of Tv could be specified in terms of hours instead of minutes because this standard does not specify a maximum value for Tv. The system violating an IROL should be brought out of that critical operating state as soon as possible. We therefore suggest Tv be capped at 30 minutes to avoid operating in a critical state for long periods of time.

Therefore, the definition of Tv should be revised to:

"Tv: The maximum time that an Interconnection Reliability Operating Limit, as determined by the Transmission Owner for equipment-based limits and by the Reliability Authority and Planning Authority for system-based limits, can be exceeded without compliance sanctions being applied. The maximum time any IROL may be exceeded is 30 minutes unless an alternative value can be shown to be more appropriate."

The Transmission Owner is responsible for establishing facility ratings for its equipment. The Transmission Owner's facility ratings must be respected by the entities that develop associated system operating limits and Interconnection Reliability Operating Limits. The new standards being developed by NERC are being developed in support of the terminology and concepts in the Functional Model. The Functional Model assigns the Reliability Authority the responsibility for identifying IROLs. To clarify that the Transmission Owner's facility ratings must be respected, this standard has been revised to include a statement indicating that the IROLs are developed from SOLs that are developed according to the Determine Facility Ratings, System Operating Limits and Transfer Capabilities Standard.

There were many industry balloters who indicated a desire to set T_v at a maximum of 30 minutes, and this change has been implemented.

Carolina Power & Light Company CPL (Transmission Owners)
Carolina Power & Light Company CPL (LSEs)
Carolina Power & Light Company CPL (Generators)
Florida Power & Light FPL
FRCC
JEA JEA (Transmission Owners)
Reedy Creek Improvement District RC (LSEs)
Reedy Creek Improvement District RC (TDUs)
Reedy Creek Improvement District RC (Generators)
Reedy Creek Improvement District Marketing RCM (Brokers)
Seminole Electric Cooperative SEC (TDUs)
Seminole Electric Cooperative SEC (Generators)
Seminole Electric Cooperative SEC (Brokers)
Kissimmee Utility Authority
Orlando Utilities Commission OUCT
Tampa Electric Company TEC (LSEs)
Tampa Electric Company TEC (Brokers)

It is unclear if an IROL event would be pre-contingency or post-contingency. This question was raised on the web cast, and it sounded like the answer was that the IROL events were all “real-time”. Should Tv should be 0 for a real-time event and something greater than 0 for a pre-contingency event? The definition of Tv states that it is the maximum time the system operator has to return to a state that is at or below the limit before being subjected to compliance sanctions. This is an inadequate definition. Tv should not be based on when compliance sanctions begin, but rather on the time the RA is willing to risk the system. This also depends whether it is pre or post contingency. It is clear that more work needs to be done in clarifying this definition.

The definition of T_v has been revised. IROL’s are based on system operating limits that are developed based on study criteria identified in the Determine Facility Ratings, System Operating Limits and Transfer Capabilities standard. IROLs are expected to be updated to match changing system conditions. IROLs are developed based on studies of pre- contingency situations and are updated in real time to address changes in system topology such as a loss of a line or a unit trip

Gainsville Regional Utilities GVL (LSEs)
City of Tallahassee TAL (Transmission Owners)

The IROL Tv continues to be an area of confusion. Tv is the maximum amount of time the system operator has to return to a state that is at or below the limit before being subjected to compliance sanctions. This does not help anyone figure out how to determine Tv. It should be based on how much time before the risk is too great.

- How is the IROL Tv calculated? If it is pre-contingency, it is really how long the RA is willing to take the risk of the contingency.
- Does the calculation of Tv depend on the tool used to determine the IROL?
- Would Tv be 0 for a real-time event and Tv be something greater fro a pre-contingency event?
- Should Tv have a maximum, for example 30 minutes?

Each RA needs to determine T_v using methodology that is reasonable for that system. T_v is intended to be risk–based and the definition of T_v has been revised to make this clarification.

T_v doesn't depend on the tool used to determine the IROL.

T_v can be between 0 and 30 minutes for any IROL.

The balloters overwhelmingly asked for a maximum T_v of 30 minutes, and this change has been implemented.

Manitoba Hydro Electric Board MHEB (Electricity Brokers, Aggregators, and Marketers)

Manitoba Hydro MHEB (LSEs)

Manitoba Hydro (Transmission Owners)

Standard 200 requires criteria to be defined for the determination of Tv as a reporting benchmark – inviting misuse of the quantity. As defined in the Standard definition section, Tv does not appear to relate to the risk in the system, the responsiveness of the operators, the complexity of restoration procedures except in a vague sense that Tv is likely too long to wait before a return below the limit. This simplistic definition is very different than the one provided in page 9 of the question and answers document issued with the Standard which states "Tv is based on system risk." Therefore this definition should be revised to reflect that Tv should be based on the potential risk to the system of not taking corrective action in a time frame less than defined by Tv. This wording should also be included in section 201a.2.i of the Standard. This definition would be similar to the rationale for the 30 minute limit defined for OSL.

Several balloters indicated a preference for a definition that references risk to the interconnection rather than compliance sanctions. The definition has been revised to reflect this preference.

Gainsville Regional Utilities GVL (LSEs)

City of Tallahassee TAL (Transmission Owners)

Tv: The maximum time that an Interconnection Reliability Operating Limit can be exceeded without compliance sanctions being applied. Shouldn't the time be based upon the time before the system is in jeopardy rather than when a sanction is applied for non-compliance? This definition would not help the RA determine what Tv should be.
Several balloters indicated a preference for a definition that references risk to the interconnection rather than compliance sanctions. The definition has been revised to reflect this preference.

City of Tallahassee TAL (Generators)

The definition of Tv in the standard does not match the intent explained in the Q&A document. By the Q&A document it includes "unacceptable" risk, shouldn't that be in the definition? " The maximum amount of time that an IROL can be exceeded without the risk to the interconnection becoming unacceptable"? IROL violations that persist for longer than Tv will result in a sanction.

Several balloters indicated a preference for a definition that references risk to the interconnection rather than compliance sanctions. The definition has been revised to reflect this preference.

Operational Planning Analysis

Summary Consideration:

Several commenters provided suggestions for improvements to the definition of Operational Planning Analysis. The definition was revised as follows:

> **Operational Planning Analysis:** An analysis of the expected system conditions for the next day's operation and up to 12 months ahead. Expected system conditions include things such as~~,~~ ~~given the~~ load forecast(s), generation output levels and known system constraints, ~~some examples being~~ (transmission facility outages, generator outages, ~~and~~ equipment limitations,

American Transmission Company LLC ATC
MAIN

The definition of "Operational Planning Analysis" refers to "expected system conditions." The use of the word "expected" leaves too much room for interpretation about which contingencies, if any, must be included in the planning analysis.

Because each RA's system is different, there may be different considerations for each RA's expected system conditions.

Entergy EES (Transmission Owners)

DEFINITION OF OPERATIONAL PLANNING ANALYSIS - Operational Planning Analysis does not address the time frame of the analysis, which as contained in the draft could inappropriately be extended to years. Operational Planning Analyses are typically conducted for the next day's operation and up to 13 months. Therefore, this definition needs to be changed to "An analysis of the expected system conditions for the next day's operation and up to 13 months ahead of expected conditions, given the load forecast(s), …."

The definition has been revised to support the concept of your recommendation but because the Functional Model uses 12 months as the suggested dividing line between operational planning and long-range planning, the revised definition of operational planning uses the phrase, 'up to 12 months ahead.'

Action Plan

Bonneville Power Administration Transmission BPAT

1) "Action Plan" should be defined in the "Definition" section of the Standard.

The standard has been revised to replace the phrase, 'action plan' with the terms, 'procedures, processes or plans'. These new terms have been used to conform with the terminology used in the Coordinate Operations standard. These terms are defined in the Coordinate Operations standard.

IROL

Summary Consideration:

The definition was revised to replace the phrase, 'bulk transmission system' with the phrase, 'bulk electric system.' This change was made because 'bulk electric system is already a defined term.

> **Interconnection Reliability Operating Limit:** A system operating limit which, if exceeded, could lead to instability, uncontrolled separation, or cascading outages that adversely impact the reliability of the bulk ~~transmission~~ electric system.

Gainsville Regional Utilities GVL (LSEs)

City of Tallahassee TAL (Transmission Owners)

Interconnection Reliability Operating Limit: A system operating limit which, if exceeded, could lead to instability, uncontrolled separation, or cascading outages that adversely impact the reliability of the bulk transmission system. Is the definition for cascading outages provided above good enough to determine an IROL?

The definition of cascading outages has been revised as follows:

> **Cascading Outages:** The uncontrolled successive loss of system elements triggered by an incident at any location~~.~~ which results in the loss of 300 MW or more of networked system load for a minimum of 15 minutes.

The revised definition should help RAs determine which SOLs are IROLs. The definition of wide area impact has also been revised to try and assist in clarifying which SOLs are IROLs. However the term, 'wide area impact' is not included in this standard and the SDT is removing it from the list of terms to be approved with this standard.

Dairyland Power Cooperative DPC

The definition of "Interconnection Reliability Operating Limit" implies that it is acceptable to operate over established limits if it would not cause cascading. Concern that this could result in a degradation of reliability.

The scope of this standard was limited to the subset of SOLs that are IROLs. The SDT recognizes that exceeding **any** SOL is unacceptable, but adding requirements to this standard that address exceeding SOLs is outside the scope of the associated SAR. The SDT is drafting another SAR to address monitoring and operating within SOLs.

Manitoba Hydro Electric Board MHEB (Electricity Brokers, Aggregators, and Marketers)

Manitoba Hydro MHEB (LSEs)

Manitoba Hydro (Transmission Owners)

There is a fundamental disconnect between standard 600 regarding the development of limits (such as System operating Limits) and the limits (IROL's) required to implement this standard. Until this disconnect is resolved or this standard is revised to deal explicitly with the development of IROL's, it is not appropriate for standard 200 to be in place. Standard 600 specifies that SOLs are to be developed as first contingency limits that ensure that all underlying limits (such as voltage, flow or stability) are not violated. IROLs are defined as SOLs which if exceeded could lead to instability, uncontrolled separation or cascading outages that adversely impact the reliability of the bulk electric system. Based on standard 600, violation of most SOLs will not lead to instability, uncontrolled separation or cascading outages. For most regions only a small subset of SOLs are likely to be IROLs. Many tightly interconnected regions will not have IROLs at all for first contingency The only time that most SOLs could conceivably be classified as IROLs would be for deliberate disregard of the limits, multiple simultaneous contingencies or a system condition which is not consistent with the study assumptions used to define the limits (as might happen if other system operating limit violations are ignored). Therefore it is unlikely that monitoring only IROLs will be an effective way to prevent instability, uncontrolled separation, or cascading outages of the bulk electric system.

The scope of this standard was limited to the subset of SOLs that are IROLs. As envisioned, there are relatively few IROLs, and many, many SOLs. The SDT recognizes that exceeding **any** SOL is unacceptable, but adding requirements to this standard that address exceeding SOLs is outside the scope of the associated SAR. The SDT is drafting another SAR to address monitoring and operating within SOLs.

Midwest Independent Transmission System Operator, Inc.

There is still is not a common understanding of an Interconnected Reliability Limit (IRL).

This standard addresses IROLs, which are a bit different from the IRLs being field-tested by the NERC Operating Limits Definition Task Force. The definitions of cascading outages and wide area impact have been revised, and these revisions should help in the understanding of what is/is not an IROL.

WECC

Minnesota Power MP

Public Works Commission Fayetteville PWCF

Southern California Edison SCET

Salt River Project SRP

Tucson Electric Power Company TEPC

Platte River Power Authority TP PRPA

The definition of Interconnection Reliability Operating Limit includes the following statement --- "A system operating limit which, if exceeded, could lead to instability, uncontrolled separation, or cascading outages that adversely impact the reliability of the bulk transmission system." This seems to imply that it is OK to operate over the established limit if it would not cause cascading, even

though it could result in damaging equipment, loss of load, or overloads on another entity's facilities. We believe that implying that limits are only exceeded if the violation could lead to "instability, uncontrolled separation, or cascading outages" will lead to a degradation of system reliability. For example, a system operator may conclude that it is acceptable to violate an operating limit as long as the consequences are not a cascading outage. This philosophy is not acceptable.
The scope of this standard was limited to the subset of SOLs that are IROLs. As envisioned, there are relatively few IROLs, and many, many SOLs. The SDT recognizes that exceeding any SOL is unacceptable, but adding requirements to this standard that address exceeding SOLs is outside the scope of the associated SAR. The SDT is drafting another SAR to address monitoring and operating within SOLs.

Power Pool of Alberta PPOA

Standard 200 needs enhanced definitions of IROL and wide area impact, in order to more precisely define the portions of power systems that IROLs are meant to protect. At a minimum there should be recognition of the need for adjacent Reliability Authorities to reach a common understanding of wide area impact.
The definitions of IROL and Wide Area Impact have both been revised to improve their understanding. Note that the term, "wide area impact' was not used in this standard. Although the SDT continues to try and help the industry reach consensus on a definition of this term, the term will be removed from the list of terms associated with this standard.

Cascading Outages

Summary Consideration: There were several comments indicating that the definition of cascading outages be refined to match the definition that had been contained within the NERC Glossary. The definition contained within the NERC Glossary reads as follows:

> **Cascading**
>
> The uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread service interruption, which cannot be restrained from sequentially spreading beyond an area predetermined by appropriate studies

Because the industry hasn't been able to agree on a definition of 'widespread' and the suggested addition uses the phrase, 'widespread', the SDT declined to revise the definition of cascading to exactly match the definition in the NERC Glossary. The SDT replaced the phrase, 'widespread' with the Department of Energy's threshold for reporting system outages through Report 417. The revised definition reads as follows:

> **Cascading Outages:** The uncontrolled successive loss of system elements triggered by an incident at any location~~.~~ which results in the loss of 300 MW or more of networked system load for a minimum of 15 minutes.

Bonneville Power Administration Transmission BPAT

Definition of Cascading outages does not match existing definition that was laboriously reviewed within NERC (the last sentence of the old definition was not included here). The widespread component of cascading in the original definition is important – some local cascading could be acceptable and must be preserved.

Because the industry hasn't been able to agree on a definition of 'widespread' and the suggested addition uses the phrase, 'widespread', the SDT declined to revise the definition of cascading to exactly match the definition in the NERC Glossary. The SDT replaced the phrase, 'widespread' with the Department of Energy's threshold for reporting system outages through Report 417. The revised definition reads as follows:

> **Cascading Outages:** The uncontrolled successive loss of system elements triggered by an incident at any location~~.~~ which results in the loss of 300 MW or more of networked system load for a minimum of 15 minutes.

WECC

Minnesota Power MP

Public Works Commission Fayetteville PWCF

Southern California Edison SCET

Salt River Project SRP

Tucson Electric Power Company TEPC

Platte River Power Authority TP PRPA

California Energy Commission

The definition of "cascading" is inconsistent with NERC definitions found elsewhere. The definition of "wide area impact" is overly broad, stating the area affected is "always larger than the local area monitored by a single transmission operator." By this definition, the affected area could be large (such as a major metropolitan area or multi-state RTO) and still not be considered a "wide area impact."

Because the industry hasn't been able to agree on a definition of 'widespread' and the suggested addition uses the phrase, 'widespread', the SDT declined to revise the definition of cascading to exactly match the definition in the NERC Glossary. The SDT replaced the phrase, 'widespread' with the Department of Energy's threshold for reporting system outages through Report 417. The revised definition reads as follows:

> **Cascading Outages:** The uncontrolled successive loss of system elements triggered by an incident at any location~~.~~ which results in the loss of 300 MW or more of networked system load for a minimum of 15 minutes.

Gainsville Regional Utilities GVL (LSEs)

City of Tallahassee TAL (Transmission Owners)

Cascading Outages: The uncontrolled successive loss of system elements triggered by an incident at any location. There are more words in the definition provided in the Q&A documents. Is this definition good enough? Does it need to impact more than one system?

Because the industry hasn't been able to agree on a definition of 'widespread' and the suggested addition uses the phrase, 'widespread', the SDT declined to revise the definition of cascading to

> **Cascading Outages:** The uncontrolled successive loss of system elements triggered by an incident at any location~~.~~ which results in the loss of 300 MW or more of networked system load for a minimum of 15 minutes.

exactly match the definition in the NERC Glossary. The SDT replaced the phrase, 'widespread' with the Department of Energy's threshold for reporting system outages through Report 417. The revised definition reads as follows:

Occurrence Period

Summary Consideration:

The definition of Occurrence Period has been separated from the definition of Performance-reset Period.

> ~~**Occurrence Period (**~~**Performance-reset Period**~~)~~**:** The time period that the entity being assessed must operate without any violations to reset the level of non-compliance to zero.
>
> **Occurrence Period:** The time period in which performance is measured and evaluated.

Bonneville Power Administration Transmission BPAT

The "Definitions" Section defines the "Occurrence Period (Performance-reset Period)" as "the time period in which performance is measured, evaluated, and then reset". The "Performance-reset Period" for each of the requirements in this Standard is 12 months and the maximum "Number of Violations in Occurrence Period at a Given Level" is "4 or more".

We recommend that the definition of "Occurrence Period" not be included in the definition of the "Performance-reset Period" but be defined on its own so that the Standard and the Compliance Sanction Table are understandable.
We recommend that the compliance processes be defined in a Compliance Standard instead of each separate standard.

The terms defined in this standard were included at the request of industry commenters. While the occurrence period is sometimes the same as the 'Performance-reset period, they do not always have to be the same. The definitions have been revised as follows:

System Operating Parameters

Bonneville Power Administration Transmission BPAT

In Section 202(b)(3), the standard indicates that the RA shall monitor "system operating parameters" which is an undefined term. It is unclear why the RA would need any information not included in the IROL to monitor the system. More explanation of what system operating parameters include is needed and how this information is different from the information in the IROL. It is recommended that "System Operating Parameters" be defined in the "Definition" section of the Standard and that it include something similar to "variables that impact the IROL".

If the SDT defines system operating parameters, then readers may interpret the requirement to mean that IROLS should be limited to the listed parameters, and this isn't the intent. The standard only addresses the system operating parameters associated with the IROLs.

Bulk Electric System

Summary Consideration:

The definition of Bulk Electric System that was posted with the standard for ballot, was the same definition that was included in the NERC Glossary of Terms, approved by the Engineering and Operating Committees in 1996. At the request of several balloters, the definition has been refined as follows:

Bulk Electric System: A term commonly applied to the portion of an electric utility system that encompasses the electrical generation resources and ~~bulk~~ high voltage transmission system (above 35 kV or as approved in a tariff filed with FERC.).

City of Lakeland PLKT

Better definition of Bulk Electric System is needed.

At the request of several balloters, the definition has been refined to indicate that it is limited to voltages higher than 35 kV or as approved in a tariff filed with FERC.

City of Lakeland PLKT

Some defintions are vague and somewhat circular. Wide Area Impact seems to be same as IROL, lack of clarity on scope of area for cascading outages, ie; single control area or RA's area or beyond ? Possible confusion with Wide Area Impact. Bulk Electric System definiton ?

The definition of Bulk Electric System that was posted with the standard for ballot, was the same definition that was included in the NERC Glossary of Terms, approved by the Engineering and Operating Committees in 1996. At the request of several balloters, the definition has been refined to indicate that it is limited to voltages higher than 35 kV or as approved in a tariff filed with FERC.

Carolina Power & Light Company CPL (Transmission Owners)

Carolina Power & Light Company CPL (LSEs)

Carolina Power & Light Company CPL (Generators)

The definition of Bulk Electric System is circular and does not help anyone understand what is the Bulk Electric System. In fact, the interim blackout report has a definition that is more specific, but we are not even sure if that is the definition that has been used in other NERC policies and standards. The definition of Wide Area Impact is really the same as the definition of IROL. This definition does not help anyone understand what a wide area really is either.

The definition of Bulk Electric System that was posted with the standard for ballot, was the same definition that was included in the NERC Glossary of Terms, approved by the Engineering and Operating Committees in 1996. At the request of several balloters, the definition has been refined to indicate that it is limited to voltages higher than 35 kV or as approved in a tariff filed with FERC.

The SDT searched the Interim Blackout Report (page 117) and found that the Report used exactly the same definition for Bulk Electric System that was used with the version of this standard posted for ballot.

Florida Power & Light FPL

FRCC

JEA JEA (Transmission Owners)
Kissimmee Utility Authority
Orlando Utilities Commission OUCT
Reedy Creek Improvement District RC (LSEs)
Reedy Creek Improvement District RC (TDUs)
Reedy Creek Improvement District RC (Generators)
Reedy Creek Improvement District Marketing RCM (Brokers)
Seminole Electric Cooperative SEC (TDUs)
Seminole Electric Cooperative SEC (Generators)
Seminole Electric Cooperative SEC (Brokers)
Tampa Electric Company TEC (LSEs)
Tampa Electric Company TEC (Brokers)

The definition of Bulk Electric System is circular and does not help anyone understand what is the Bulk Electric System. In fact, the interim blackout report has a definition that is more specific, but we are not even sure if that is the definition that has been used in other NERC policies and standards.

The definition of Bulk Electric System that was posted with the standard for ballot, was the same definition that was included in the NERC Glossary of Terms, approved by the Engineering and Operating Committees in 1996. At the request of several balloters, the definition has been refined to indicate that it is limited to voltages higher than 35 kV or as approved in a tariff filed with FERC.

The SDT searched the Interim Blackout Report (page 117) and found that the Report used exactly the same definition for Bulk Electric System that was used with the version of this standard posted for ballot.

Wide Area Impact

The impact of ~~an event~~ a single incident resulting in uncontrolled loss of 300 MW or more of networked system load for a minimum of 15 minutes. ~~that, if left untended, could lead to voltage instability, cascading outages or uncontrolled separation that jeopardizes the reliability of an interconnection. The geographic size of the area affected by such an event is always larger than the local area monitored by a single transmission operator and may also be larger than a single Reliability Authority's area.~~

Summary Consideration:

The SDT did not use the term, 'wide area impact' in this standard. There is no industry consensus on the definition of this term. The Functional Model Review Task Group has declined to develop a definition, and the Operate in Limits Definition Task Force has not been successful in reaching a concise definition. The SDT will request that this term continue to be refined, but recommends that this refinement take place outside the scope of this standard. The SDT revised the definition to conform to the Department of Energy threshold for reporting disturbances as defined in DOE Form EIA-417. The DOE Form EIA-417 uses the following criteria for reporting disturbances:

> "Uncontrolled loss of 300 MW or more of firm system loads for more than 15 minutes from a single incident"

City of Lakeland PLKT

Better definition of Wide Area Impact is needed.

The SDT did not use the term, 'wide area impact' in this standard. There is no industry consensus on the definition of this term. The SDT will request that this term continue to be refined, but recommends that this refinement take place outside the scope of this standard.

City of Lakeland PLKT

Some definitions are vague and somewhat circular. Wide Area Impact seems to be same as IROL, lack of clarity on scope of area for cascading outages, ie; single control area or RA's area or beyond ? Possible confusion with Wide Area Impact . Bulk Electric System definition?

The SDT did not use the term, 'wide area impact' in this standard. There is no industry consensus on the definition of this term. The SDT will request that this term continue to be refined, but recommends that this refinement take place outside the scope of this standard.

Duke Power DUKE (Electric Generators)

Duke Power DUKE (LSEs)

Duke Power DUKE (Transmission Owners)

The definition of "wide area" is still being developed. Industry needs to reach consensus definition of this term prior to its being utilized in a Standard.
Recommend that this definition be completed prior to being used in a Standard.

The SDT did not use the term, 'wide area impact' in this standard. There is no industry consensus on the definition of this term. The SDT will request that this term continue to be refined, but recommends that this refinement take place outside the scope of this standard.

Carolina Power & Light Company CPL (Transmission Owners)

Carolina Power & Light Company CPL (LSEs)

Carolina Power & Light Company CPL (Generators)

The definition of Bulk Electric System is circular and does not help anyone understand what is the Bulk Electric System. In fact, the interim blackout report has a definition that is more specific, but we are not even sure if that is the definition that has been used in other NERC policies and standards.The definition of Wide Area Impact is really the same as the definition of IROL. This definition does not help anyone understand what a wide area really is either.

The SDT did not use the term, 'wide area impact' in this standard. There is no industry consensus on the definition of this term. The SDT will request that this term continue to be refined, but recommends that this refinement take place outside the scope of this standard.

ISO New England Inc ISNE

The Standard does not include clear definitions or criteria on how "local" and "Wide Area Impact" are determined. Therefore, it is difficult to assess what electrical boundaries an IROL is meant to protect. This definition of Wide Area Impact points out that the electrical area to be included in the limit may be larger than the portion of the transmission system under the authority of a single Reliability Authority (RA). This indicates the need for studies and associated limits that transcend the boundaries of a single RA's purview, yet there is no formal statement identifying this need in standard, 200, 600 or the Co-ordinate Operations Standard (currently under development).

The SDT did not use the terms, 'wide area impact' or 'local area' in this standard. There is no industry consensus on the definition of these terms. The SDT will request that these terms continue to be refined, but recommends that this refinement take place outside the scope of this standard.

Electricity Consumers Resource Council

We are concerned that the definition or criteria regarding the differentiation between "Local" and "Wide Area Impact" is unclear. The proposed standard does not appear to provide adequate responses if the electric area to be included in the limit is larger than the portion of the transmission system under the authority of a single Reliability Authority (RA). The standard should clearly explain how an RA can order all TO's, BA's, IA's and other RA's to take necessary actions if they are not within the controlling RA's reliability area.

The SDT did not use the terms, 'wide area impact' or 'local area' in this standard. There is no industry consensus on the definition of these terms. The SDT will request that these terms continue to be refined, but recommends that this refinement take place outside the scope of this standard.

The Coordinate Operations standard addresses the coordination of actions between two RAs. There is a requirement in this standard that requires the entities that work under the direction of an RA to follow that RA's directives. RA Certification is expected to include requirements that the RA have written agreements with all entities that operate within its physical and/or electrical boundaries. These agreements are expected to address the authority of the RA to direct entities to take actions under normal and abnormal conditions.

Exelon Energy Delivery EED - PECO & ComEd (LSEs)

Exelon Generation Company LLC EXGN

Exelon believes that the definition of "Wide Area Impact" is incorrect. The second sentence of the defintion states, "The geographic size of the area affected by such an event is always larger than a single Reliability Authority's area". This implies that a blackout confined to a major city monitored by a single transmission operator is not a violation of this Standard. Such an event not being a violation of this standard could lead to the conclusion that this Standard is not accomplishing it's objective. Exelon suggests that the second sentence be removed.

The SDT did not use the term, 'wide area impact' in this standard. There is no industry consensus on the definition of this term. The SDT will request that this term continue to be refined, but recommends that this refinement take place outside the scope of this standard.

MAIN

We believe that the definition of "Wide Area Impact" is incorrect. The second sentence of the definition states, "The geographic size of the area affected by such an event is always larger than the local area monitored by a single transmission operator and may also be larger than a single Reliability Authority's area". This implies that a blackout confined to a major city monitored by a single transmission operator is not a violation of this standard. Such an event not being a violation of this standard could lead to the conclusion that this standard is not accomplishing its objective. We suggest the second sentence be removed.

The SDT did not use the term, 'wide area impact' in this standard. There is no industry consensus on the definition of this term. The SDT will request that this term continue to be refined, but recommends that this refinement take place outside the scope of this standard.

The scope of this standard was limited to the subset of SOLs that are IROLs. The SDT recognizes that exceeding **any** SOL is unacceptable, but adding requirements to this standard that address exceeding SOLs is outside the scope of the associated SAR. The SDT is drafting another SAR to address monitoring and operating within SOLs.

FirstEnergy Corp

It is difficult to establish what areas, or electrical boundaries, are to be protected. The standard does not give clear definition on how local or wide area impacts are determined.
IROL's are based on system operating limits that are developed based on study criteria identified in the Determine Facility Ratings, System Operating Limits and Transfer Capabilities standard. IROLs are expected to be updated to match changing system conditions. . Each RA is expected to study its SOLs to determine which ones could lead to voltage instability, cascading outages or uncontrolled separation. IROLs are developed based on studies of pre- contingency situations and are updated in real time to address changes in system topology such as a loss of a line or a unit trip

Note that the SDT did not use the terms, 'wide area impact' and 'local impact' in this standard. There is no industry consensus on the definitions of these terms. The SDT will request that these terms continue to be refined, but recommends that this refinement take place outside the scope of this standard.

Florida Power & Light FPL

FRCC

JEA JEA (Transmission Owners)
Kissimmee Utility Authority

Orlando Utilities Commission OUCT

Reedy Creek Improvement District RC (LSEs)

Reedy Creek Improvement District RC (TDUs)

Reedy Creek Improvement District RC (Generators)

Reedy Creek Improvement District Marketing RCM (Brokers)

Seminole Electric Cooperative SEC (TDUs)

Seminole Electric Cooperative SEC (Generators)

Seminole Electric Cooperative SEC (Brokers)

Tampa Electric Company TEC (LSEs)

Tampa Electric Company TEC (Brokers)

The definition of Wide Area Impact is really the same as the definition of IROL. This definition does not help anyone understand what a wide area really is either.

The SDT did not use the term, 'wide area impact' in this standard. There is no industry consensus on the definition of this term. The SDT will request that this term continue to be refined, but recommends that this refinement take place outside the scope of this standard.

Hydro-Quebec HQT

The Standard does not include clear definitions or criteria on how "local" and "Wide Area Impact" are determined. Therefore, it is difficult to assess what electrical boundaries an IROL is meant to protect. This definition of Wide Area Impact points out that the electrical area to be included in the limit may be larger than the portion of the transmission system under the authority of a single Reliability Authority (RA). This indicates the need for studies and associated limits that transcend the boundaries of a single RA's purview, yet there is no formal statement identifying this need in standard, 200, 600 or the Co-ordinate Operations Standard (currently under development).

Note that the SDT did not use the terms, 'wide area impact' and 'local impact' in this standard. There is no industry consensus on the definitions of these terms. The SDT will request that these terms continue to be refined, but recommends that this refinement take place outside the scope of this standard.

The SDT does expect that studies will need to be conducted in advance and will need to look beyond a single RA's Reliability Area. There were several suggestions that the standard be revised to include a requirement that the identification of IROLs be coordinated between adjacent RAs within an Interconnection. The standard has been revised to include this requirement.

WECC

Minnesota Power MP

Public Works Commission Fayetteville PWCF

Southern California Edison SCET

Salt River Project SRP

Tucson Electric Power Company TEPC

Platte River Power Authority TP PRPA

The definition of "cascading" is inconsistent with NERC definitions found elsewhere. The definition of "wide area impact" is overly broad, stating the area affected is "always larger than the local area monitored by a single transmission operator." By this definition, the affected area could be large (such as a major metropolitan area or multi-state RTO) and still not be considered a "wide area impact."

Note that the SDT did not use the terms, 'wide area impact' and 'local impact' in this standard. There is no industry consensus on the definitions of these terms. The SDT will request that these terms continue to be refined, but recommends that this refinement take place outside the scope of this standard.

The SDT did update its definition of 'cascading' to clarify what was intended. The new definition of 'cascading outages' is as follows:

> The uncontrolled successive loss of system elements triggered by an incident at any location which results in the loss of 300 MW or more of networked system load for a minimum of 15 minutes.

The new definition of cascading outages conforms with the threshold criteria used for reporting outage-related disturbances to the Department of Energy.

The scope of this standard was limited to the subset of SOLs that are IROLs. The SDT recognizes that exceeding **any** SOL is unacceptable, but adding requirements to this standard that address exceeding SOLs is outside the scope of the associated SAR. The SDT is drafting another SAR to address monitoring and operating within SOLs.

Gainsville Regional Utilities GVL (LSEs)
City of Tallahassee TAL (Transmission Owners)

Wide Area Impact: The impact of an event that, if left untended, could lead to voltage instability, cascading outages or uncontrolled separation that jeopardizes the reliability of an interconnection. (This is really the same as the definition for the IROL. Are they really trying to define "wide area"? This does not seem to be correct. What does it add?) The geographic size of the area affected by such an event is always larger than the local area monitored by a single transmission operator and may also be larger than a single Reliability Authority's area.

Note that the SDT did not use the terms, 'wide area impact' and 'local impact' in this standard. There is no industry consensus on the definitions of these terms. The SDT will request that these terms continue to be refined, but recommends that this refinement take place outside the scope of this standard.

The SDT did update its definition of 'cascading' to clarify what was intended. The new definition of 'cascading outages' is as follows:

> The uncontrolled successive loss of system elements triggered by an incident at any location which results in the loss of 300 MW or more of networked system load for a minimum of 15 minutes.

The new definition of cascading outages conforms with the threshold criteria used for reporting outage-related disturbances to the Department of Energy.

Power Pool of Alberta PPOA

Standard 200 needs enhanced definitions of IROL and wide area impact, in order to more precisely define the portions of power systems that IROLs are meant to protect. At a minimum there should be recognition of the need for adjacent Reliability Authorities to reach a common understanding of wide area impact.

The SDT does expect that studies will need to be conducted in advance and will need to look beyond a single RA's Reliability Area. There were several suggestions that the standard be revised to include a requirement that the identification of IROLs be coordinated between adjacent RAs within an Interconnection. The standard has been revised to include this requirement.

Sacramento Municipal Utility District SMUD

The definition of "Wide Area Impact" is overly broad.

Note that the SDT did not use the terms, 'wide area impact' and 'local impact' in this standard. There is no industry consensus on the definitions of these terms. The SDT will request that these terms continue to be refined, but recommends that this refinement take place outside the scope of this standard.

The SDT did update its definition of 'cascading' to clarify one of the probable impacts of exceeding an IROL for a time greater than T_v. The new definition of 'cascading outages' is as follows:

> The uncontrolled successive loss of system elements triggered by an incident at any location which results in the loss of 300 MW or more of networked system load for a minimum of 15 minutes.

The new definition of cascading outages conforms with the threshold criteria used for reporting outage-related disturbances to the Department of Energy.

Southern Company Services SOCO (Generators)
Southern Company Services SOCO (Transmission Owners)
Georgia Power Company (LSEs)

Wide Area/Local Area
The following definition is included in the standard. Although this is a start in the right direction, the NERC OC indicated a need for better defining wide and local areas. It seems that it would be prudent to wait and include any clarifications to the definitions from the OLDTF and/or RCWG. This is an example of two different, but related objectives working on incongruous timetables. Southern Company Services SOCO (Generators)

As interpreted from the note pertaining to definitions on page 1 of the standard, a vote for approving this standard also approves the definitions within even though the definitions will be pulled out into a separate definitions document. If the separate definitions document can then be easily modified according to subsequent recommendations from the OLDTF and RCWG, this would help alleviate this issue.

The SDT did not use the terms, ‘wide area impact’ or ‘local area’ in this standard. There is no industry consensus on the definition of these terms. The SDT will request that these terms continue to be refined, but recommends that this refinement take place outside the scope of this standard.

Note that the FMRTG could not agree on a definition of Wide Area, and the SDT did not find that the definition produced by the OLDTF is useful in determining the scope of the ‘wide area’. The OLDTF’s definitions for Local Area and Widespread Area are

> Local Area: The portion of a Widespread Area, predetermined by appropriate analyses, where the impact of a Contingency or other event will not cause instability, uncontrolled separations or cascading outages to propagate beyond the local boundaries (i.e, will not impact the overall reliability of a major portion of the Interconnection.) Impact to a Widespread Area indicates significant impact to the Interconnection.
>
> Widespread Area: Any area that extends beyond any predefined Local Area.

The SDT did refine the definition of cascading outages to help clarify one of the probable impacts of exceeding an IROL. The refined definition of cascading outages ties to the threshold criteria used for reporting outage-related disturbances to the Department of Energy. The new definition of cascading outages is:

> “The uncontrolled successive loss of system elements triggered by an incident at any location which results in the loss of 300 MW or more of networked system load for a minimum of 15 minutes.”

Western Area Power Administration - CM WACM

There needs to be further development in the definitions of “wide- spread” and “local” impact.
The SDT did not use the terms, ‘wide area impact’ or ‘local area’ in this standard. There is no industry consensus on the definition of these terms. The SDT will request that these terms continue to be refined, but recommends that this refinement take place outside the scope of this standard.

Wisconsin Energy Corporation - PM WEC

Do not agree that the area must be larger than a single transmission operator.

The SDT did not use the terms, ‘wide area impact’ or ‘local area’ in this standard. There is no industry consensus on the definition of these terms. The SDT will request that these terms continue to be refined, but recommends that this refinement take place outside the scope of this standard.

The scope of this standard was limited to the subset of SOLs that are IROLs. The SDT recognizes that exceeding **any** SOL is unacceptable, but adding requirements to this standard that address exceeding SOLs is outside the scope of the associated SAR. The SDT is drafting another SAR to address monitoring and operating within SOLs.

Local Area

Electricity Consumers Resource Council

We are concerned that the definition or criteria regarding the differentiation between “Local” and “Wide Area Impact” is unclear. The proposed standard does not appear to provide adequate responses if the electric area to be included in the limit is larger than the portion of the transmission system under the authority of a single Reliability Authority (RA). The standard should clearly explain how an RA can order all TO’s, BA’s, IA’s and other RA’s to take necessary actions if they are not within the controlling RA’s reliability area.

The SDT did not use the terms, ‘wide area impact’ or ‘local area’ in this standard. There is no industry consensus on the definition of these terms. The SDT will request that these terms continue to be refined, but recommends that this refinement take place outside the scope of this standard.

The scope of this standard was limited to the subset of SOLs that are IROLs. The SDT recognizes that exceeding **any** SOL is unacceptable, but adding requirements to this standard that address exceeding SOLs is outside the scope of the associated SAR. The SDT is drafting another SAR to address monitoring and operating within SOLs.

201 IROL Identification

Requirements

(a) Requirements

(1) The Reliability Authority shall identify and document which Facilities (or groups of Facilities) in ~~the~~ its ~~Reliability Authority's~~ Reliability Authority Area are subject to Interconnection Reliability Operating Limits[1]. (footnote: [1] Each IROL is developed by following the requirements in the Determine Facility Ratings, System Operating Limits and Transfer Capabilities Standard.)

(ii) All Reliability Authorities that share a Facility (or group of Facilities) shall agree on whether that Facility (or group of Facilities) is (are) subject to Interconnection Reliability Operating Limits.

(2) The Reliability Authority shall identify ~~each~~ Interconnection Reliability Operating Limits for its ~~within the Reliability Authority's~~ Reliability Authority Area. Each Interconnection Reliability Operating Limit shall have a T_v that is smaller than or equal to 30 minutes.

~~(i) The Reliability Authority shall identify a T_v for each Interconnection Reliability Operating Limit.~~

(3) All Reliability Authorities that share a Facility (or group of Facilities) subject to an Interconnection Reliability Operating Limit, shall agree upon the process used to determine that Interconnection Reliability Operating Limit and its associated T_v

Summary Consideration:

Several balloters indicated a need to have coordination between RAs in setting IROLs that involve more than one RA. The SDT added a requirement that RAs sharing a Facility must have a process for determining whether that Facility is subject to IROLs and for setting the IROL and its T_v.

Several balloters indicated that there needs to be a formal link between this standard and Standard 600. The link was added to the first requirement, and indicates that each IROL is developed following the requirements in the Determine Facility Ratings, System Operating Limits and Transfer Capabilities standard.

Many balloters requested that T_v be set at a maximum of 30 minutes, and this upper limit was added to the definition of T_v as well as to this requirement.

- ***Add other Functions***

Georgia Power Company (LSEs)
Southern Company Services SOCO (Generators)
Southern Company Services SOCO (Transmission Owners)

The standard has been changed so that the RA is the responsible party for managing IROLs. Although the supporting documentation for this standard indicates that responsibilities CAN be delegated (see excerpt below), it is important to note that the ultimate responsibility lies with the RA and the standard itself does not speak to a delegation of responsibilities.

The technical discussion of the Functional Model includes a discussion on delegating tasks, and clearly states that a task may be delegated, but not its associated responsibilities for compliance. The SDT doesn't believe it is necessary to add language to each of the standards indicating that a requirement may be delegated. Note that if this task is delegated, the RA is still responsible for compliance.

MAIN

The standard as drafted appears to place a sole responsibility with the Reliability Authority for determining which "facilities," Interconnection Reliability Operating Limits, and Tv are appropriate. It was stated on the informational call held by NERC that the RA is assumed to be the local system operator not the Reliability Coordinator. At least some members are of the opinion that the RA should work jointly, and in cooperation, with the Reliability Coordinator, Control Area Operator, Transmission Owner, Transmission Operator and Transmission Provider to accomplish the identification called for in section 201. This is a reasonable approach that will ensure complete identification of the facilities and limits, and further ensure a common understanding of any directives from the RA. The measurements could remain as stated.

New reliability standards are being developed using the terminology defined in the Functional Model. Only functions identified in the Functional Model are assigned responsibility for requirements in these new standards. The Reliability Coordinator and Control Area Operator are not 'functions' defined in the Functional Model and will not be identified as being responsible for any requirements in the new standards.

- ***Set T_v at a Max of 30 min***

AEP Service Corp -- Transmission System AEP (Transmission Owners)

Tv, which is defined as the maximum time that an Interconnection Reliability Operating Limit (IROL) can be exceeded without compliance sanctions being applied, has no maximum limit. Currently policy requires OSL violations to be corrected within 30 minutes. The proposed standard would allow a Reliability Coordinator to choose what he believes to be an appropriate Tv for each IROL. With no maximum Tv required, there is potential for Reliability Coordinators to choose something much longer than 30 minutes in order to minimize their exposure to a compliance sanction. Placing no restrictions on how long an IROL can be exceeded is not in the best interest of reliability.

The standard has been changed to indicate that T_v cannot be set higher than 30 minutes. The RA should establish a T_v that is appropriate to each IROL. IROLs should **never** be exceeded for any length of time, but because operations can't always be predicted, there are events that occur that can cause an IROL to be exceeded. The T_v is a recognition that system operators can't re-dispatch or reconfigure their system instantaneously and T_v allows the system operators some time to take corrective actions before the risk to the interconnection becomes unacceptable.

Allegheny Power AP

Tv should have a default value of 30 minutes. Variations should be permitted with reason.

There were many balloters who indicated a need to set an upper limit on T_v and the standard has been changed to include this restriction.

Bonneville Power Administration Transmission BPAT

We recommend a NERC maximum Tv of 30 minutes with the option for the NERC Region and/or the Reliability Authority to set a shorter Tv as appropriate.

There were many balloters who indicated a need to set an upper limit on T_v and the standard has been changed to include this restriction.

Boston Edison Company BECO (Transmission Owners)

NSTAR shares the general concern that the standard is not specific relative to the time in which the system should be placed back to a secure state. This leaves the requirement as an open ended one and we feel it should have a maximum duration established, preferably 30 minutes.

There were many balloters who indicated a need to set an upper limit on T_v and the standard has been changed to include this restriction.

City Water Light & Power CWLP

There is no upper limit to Tv. I believe it should have an upper limit of 30 minutes.

There were many balloters who indicated a need to set an upper limit on T_v and the standard has been changed to include this restriction.

Con Edison Company of New York CEPD (LSEs)
Con Edison Company of New York CEPD (Brokers)
Consolidated Edison Co. of New York NYCE (Generators)

The existing NERC Policy 2 limits the time an IROL shall be exceeded to 30 minutes. Permitting a Reliability Authority to establish a Tv in excess of 30 minutes for certain IROLs, as permitted by the proposed Standard 200, implies that not restricting the maximum value of Tv poses no threat to reliability. However, we know of no method for calculating the reliability risk of increasing Tv above 30 minutes. Moreover, if Reliability Authorities were permitted the option of expanding Tv beyond 30 minutes according to what they perceive as acceptable risk, the reliability of neighboring systems will be impacted by decisions they have no control over.

There were many balloters who indicated a need to set an upper limit on T_v and the standard has been changed to include this restriction.

In addition, some balloters indicated a concern about the need for more specific coordination of IROLs on 'shared' facilities. The standard was revised to include a requirement that RAs develop a single IROL with a single T_v for each shared Facility (or group of Facilities) subject to IROLs.

Consumers Energy CETR (LSEs)

Tv should not be left without a default value that represents a generally recognized value used by much of the industry.

Tv should have a default value assigned of 30 minutes. If explicitly justified and coordinated with other RA's or entities whose areas may be affected by by the IROL, the Reliability Authority should then have the ability to override the default value.

There were many balloters who indicated a need to set an upper limit on T_v and the standard has been changed to include this restriction. Requiring a default of 30 minutes defeats the purpose of allowing RAs the flexibility of developing a T_v that is best for each IROL.

Some balloters indicated a concern about the need for more specific coordination of IROLs on ‘shared’ facilities. The standard was revised to include a requirement that RAs develop a single IROL with a single T_v for each shared Facility (or group of Facilities) subject to IROLs.

Consumers Energy CETR (TDUs)

Consumers Energy votes against this proposed standard because it fails to establish specific Interconnection Reliability Operating Limit measures and specific Tv values for those measures. Further it leaves the development of such measures to each Reliability Authority, thus potentially causing significant differences in compliance requirements between control areas without a workable mechanism to come to concensus on the appropriate measures and Tv values.

There were many balloters who indicated a need to set an upper limit on T_v and the standard has been changed to include this restriction.

Some balloters indicated a concern about the need for more specific coordination of IROLs on ‘shared’ facilities. The standard was revised to include a requirement that RAs develop a single IROL with a single T_v for each shared Facility (or group of Facilities) subject to IROLs.

Duke Power DUKE (Electric Generators)
Duke Power DUKE (LSEs)
Duke Power DUKE (Transmission Owners)

This standard has “lost” the recognition of current Policy that recovery from an OSL violation should be capped at some maximum amount of time. Recommend that a maximum time for recovery be developed which will limit the exposure of the Interconnection to the OSL risk while recognizing the various time duration assumptions used in the development of the associated equipment rating(s).

This standard was intended to change the focus of system operators from ‘recovery’ to ‘prevention’. This standard includes several requirements that are more explicit and more stringent than the language in Policy 2. Collectively, these new requirements aim to help the system operator be more focused in monitoring limits and taking actions to PREVENT instances of exceeding any IROLs. The standard does recognize that there may be instances where an IROL is exceeded, and the standard requires that system operators have a plan to follow so that if faced with the situation, the system operator will know what to do to mitigate the incident.

There were many balloters who indicated a need to set an upper limit on T_v and the standard has been changed to include this restriction.

Electricity Consumers Resource Council

NERC's current Operating Policy 2 limits the time an IROL (TV) can be exceeded without compliance sanctions to a maximum of 30 minutes. The proposed standard implies that TV's may be greater than 30 minutes. This change must be more fully explained.

NERC's Policy 2 focuses on 'recovery' when a limit has been exceeded. The SDT drafted this standard to change the focus from 'recovery' to 'prevention'. This standard includes new requirements that go beyond what is required in Policy 2. The new standard puts most of its emphasis on preventing instances of exceeding an IROL. The new standard requires that system operations:

- Have a list of their facilities subject to IROLs
- Be able to identify current IROLs with a T_v for each
- Have procedures, processes or plans for preventing as well as mitigating instances of exceeding IROLs
- Conduct operational planning analyses and real time assessments with a focus on IROLs
- Take action or direct others to take action to prevent instances of exceeding IROLs

Because exceeding an IROL for any length of time is a risk to the interconnection, the SDT initially did not think that it was necessary to set an 'upper limit' on the duration of T_v. However, the balloters have clearly indicated a desire to have an 'upper limit' and the standard has been changed to add an upper limit for T_v of 30 minutes.

Exelon Energy Delivery EED - PECO & ComEd (LSEs)
Exelon Generation Company LLC EXGN

Exelon believes that a maximim Tv should be established, and a requirement should be put in place for the coordination of Tv for tie-lines and for limiting elements in different RAs that are results of a common contingency

There were many balloters who indicated a need to set an upper limit on T_v and the standard has been changed to include this restriction.

Some balloters indicated a concern about the need for more specific coordination of IROLs on 'shared' facilities. The standard was revised to include a requirement that RAs develop a single IROL with a single T_v for each shared Facility (or group of Facilities) subject to IROLs.

FirstEnergy Corp

FirstEnergy does not agree that there should be an open ended position on the Tv. The development of Tv, as stated in the standard, is open to determination by the Reliability Authority. There needs to be a maximum time limit established, such as the current 30 minute as stated in NERC policy

There were many balloters who indicated a need to set an upper limit on T_v and the standard has been changed to include this restriction.

FirstEnergy Solutions FESC (LSEs)

FES does not agree that the Tv should be open ended to determination by the Reliability Authority.

There were many balloters who indicated a need to set an upper limit on T_v and the standard has been changed to include this restriction.

FirstEnergy Solutions FESC (Brokers, Aggregators, and Marketers)

My main concern is that standards should not left up to determiniation by the individual RAs. Since the individual RAs have a different risk tolerance, the standards may vary over the different RAs and may impact the market.

Some balloters indicated a concern about the need for more specific coordination of IROLs on 'shared' facilities. The standard was revised to include a requirement that RAs develop a single IROL with a single T_v for each shared Facility (or group of Facilities) subject to IROLs.

Gainesville Regional Utilities GVL (Generators)

I also believe that IROL Tv should be defined(30 Minutes).

There were many balloters who indicated a need to set an upper limit on T_v and the standard has been changed to include this restriction.

Great River Energy GRE

I have concerns about having an undefined upper limit on Tv. I would suggest thirty minutes if anything greater than thirty minutes being adopted as an exception to the standard needing approval by the appropriate committee.

There were many balloters who indicated a need to set an upper limit on T_v and the standard has been changed to include this restriction.

Hydro One Networks Inc. (Transmission Owners)

We are very much concerned that the a diluted version of the existing standard is posted for approval post August 14 outage.
Core Reliabilility Standards such as this one should be extremely stringent and prescribed for all entities. Entities such as RC or CA should not have inconsistent practices to determine their own Tv. As a minumum maximum value of Tv should be prescribed.

NERC's Policy 2 focuses on 'recovery' when a limit has been exceeded. The SDT drafted this standard to change the focus from 'recovery' to 'prevention'. This standard includes new requirements that go beyond what is required in Policy 2. The new standard puts most of its emphasis on preventing instances of exceeding an IROL. The new standard requires that system operations:

- Have a list of their facilities subject to IROLs
- Be able to identify current IROLs with a T_v for each
- Have procedures, processes or plans for preventing as well as mitigating instances of exceeding IROLs
- Conduct operational planning analyses and real time assessments with a focus on IROLs
- Take action or direct others to take action to prevent instances of exceeding IROLs

Because exceeding an IROL for any length of time is a risk to the interconnection, the SDT initially did not think that it was necessary to set an 'upper limit' on the duration of T_v. However, the balloters have clearly indicated a desire to have an 'upper limit' and the standard has been changed to add an upper limit for T_v of 30 minutes.

Some balloters indicated a concern about the need for more specific coordination of IROLs on 'shared' facilities. The standard was revised to include a requirement that RAs have an agreed upon process for developing IROLs for each shared Facility (or group of Facilities) subject to IROLs.

Hydro One Networks Inc (LSEs)

The value TV defined in the standard at the time an Interconnection Reliability Operating Limit (IROL) can be exceeded within compliance is not given a maximum limit as presently stated in NERC's Operating Policy 2. The proposed draft does not limit the values and implies that violations of over 30 minutes are acceptable to the North American Bulk Power System. The lack of method to determine acceptable risks is of special concern after the experience of the August 14th, 2003 events. Hydro One Networks does not support the concept that response times grater than 30 minutes are acceptable.

There were many balloters who indicated a need to set an upper limit on T_v and the standard has been changed to include this restriction.

Hydro-Quebec HQT

The proposed Standard implies that Tv's may be greater than 30 minutes and may represent an acceptable risk to the North American bulk power system. There is no method or criteria established for determining acceptable risk or impact on reliability identified in the Standard or the associated Q&A. Therefore, it is difficult to support the statement that a response time greater than 30 minutes is acceptable.

There were many balloters who indicated a need to set an upper limit on T_v and the standard has been changed to include this restriction.

New York Power Authority MED
National Grid USA
New Brunswick Power Corporation NBPC
Niagara Mohawk NMPC
New York Power Authority MED
Northeast Utilities NU
Nova Scotia Power NSPI
Ontario - Independent Electricity Market Operator IMO
United Illuminating UICO
New York Power Authority NYPA
ISO New England Inc ISNE

It is National Grid's (NPCC's) (UI's) (ISO-NE's) position that Tv, the time an IROL can be exceeded without compliance sanctions, be limited to a maximum of 30 minutes as presently stated in NERC Operating Policy 2. The proposed Standard implies that Tv's may be greater than 30 minutes and may represent an acceptable risk to the North American bulk power system. There is no method or criteria established for determining acceptable risk or impact on reliability identified in the Standard or the associated Q&A. Therefore, it is difficult to support the statement that a response time greater than 30 minutes is acceptable.

There were many balloters who indicated a need to set an upper limit on T_v and the standard has been changed to include this restriction.

Kansas City Power & Light KCPL

The standard must state the maximum time allowed for Tv

There were many balloters who indicated a need to set an upper limit on T_v and the standard has been changed to include this restriction.

MAAC

I agree with commenters who suggest that there should be a 30 minute maximum limit to Tv, the "at risk" interval, and with the obligation that action should be initiated as soon as possible after recognition that a limit has been exceeded. I don't think that these are reasons enough to vote no, but would support them as additions to the standard.

There were many balloters who indicated a need to set an upper limit on T_v and the standard has been changed to include this restriction.

MAIN

A maximum Tv should be established, and further a requirement should be put in place for the coordination of Tv for tie-lines and for limiting elements in different RAs that are results of a common contingency. This is the time that the Reliability Authority has to bring the violation back within limits. The current time maximum value for SOL's is 30 minutes. The proposed standard for this new subset of SOL's that effect interconnections doesn't have a cap and should if this standard will have any teeth, plus the standard should exemplify to the public that the industry is concerned about reliability Retaining 30 minutes as the cap is reasonable.

There were many balloters who indicated a need to set an upper limit on T_v and the standard has been changed to include this restriction.

Some balloters indicated a concern about the need for more specific coordination of IROLs on ‘shared’ facilities. The standard was revised to include a requirement that RAs have an agreed upon process for developing IROLs for each shared Facility (or group of Facilities) subject to IROLs.

Midwest Independent Transmission System Operator, Inc.

There should be some maximum cap on Tv.

There were many balloters who indicated a need to set an upper limit on T_v and the standard has been changed to include this restriction.

Mirant Americas Energy Marketing LP MAEM

Under Section 201, concerned that a maximum Tv is not defined for the interconnect. Can appreciate the drafting teams intent here (allow flexibility), but we're supposed to be talking about the reliability of the interconnection here, and I have a tough time understanding how there isn't a maximum Tv for the interconnection.

There were many balloters who indicated a need to set an upper limit on T_v and the standard has been changed to include this restriction.

New York State Reliability Council

LIPA LIPA (Transmission Owners)

Allowing Tv to exceed 30 minutes as permitted by proposed Standard 200 would degrade NERC criteria and therefore would threaten reliability by increasing the risk of voltage instability, cascading outages, and uncontrolled system separation.

The existing NERC Policy 2 limits the time an IROL shall be exceeded to 30 minutes. Permitting a Reliability Authority to establish a Tv in excess of 30 minutes for certain IROLs, as permitted by the proposed Standard 200, implies that not restricting the maximum value of Tv poses no threat to reliability. However, we know of no method for calculating the reliability risk of increasing Tv above 30 minutes. Moreover, if Reliability Authorities were permitted the option of expanding Tv beyond 30 minutes according to what they perceive as acceptable risk, the reliability of neighboring systems will be impacted by decisions they have no control over.
There were many balloters who indicated a need to set an upper limit on T_v and the standard has been changed to include this restriction.

Some balloters indicated a concern about the need for more specific coordination of IROLs on 'shared' facilities. The standard was revised to include a requirement that RAs have an agreed upon process for developing IROLs for each shared Facility (or group of Facilities) subject to IROLs.

NPCC

LIPA LIPA (Transmission Owners)

T_v, the time an IROL can be exceeded without compliance sanctions, should be limited to a **maximum** of 30 minutes as presently stated in NERC Operating Policy 2.

There were many balloters who indicated a need to set an upper limit on T_v and the standard has been changed to include this restriction.

Northeast Utilities NU

The Standard must, as a minimum, clearly define the acceptable time of violation for each IROL. The Standard is developed to address contigencies that could result in instability, voltage collapse, uncontrolled separation and/or cascading outages that could impact the integrated bulk power system.

There were many balloters who indicated a need to set an upper limit on T_v and the standard has been changed to include this restriction.

Transmission Agency of Northern California – TANC

The other reason we are voting "No" is that in the standard, the time allowed for the system to return to safe operating limits following a disturbance (Tv) is a variable whose value is based on the particular limit being violated. This concept is fine. However, there is no upper limit to Tv. The Reliability Authority is responsible for setting Tv, but without a limit on the maximum amount of time allowed to return the system to within its operating limits, some areas could end up setting values of Tv that could put other areas at risk.

There were many balloters who indicated a need to set an upper limit on T_v and the standard has been changed to include this restriction.

NYISO

Ontario - Independent Electricity Market Operator IMO

New England ISO

The Standard 200 does not set a maximum limit to the "at risk" interval ("T_v" in Standard 200 - the time a Reliability Operating Limit can be exceeded without compliance sanctions). Current NERC policy effectively establishes a maximum "at risk" interval of 30 minutes, and we believe this must be carried forward in Standard 200 to ensure a timely and implementation of the standard and for the standard to meet reliability objectives. Providing future flexibility for the Reliability Authority, or some other authority, to establish an acceptable longer "at risk" interval may be possible, but we recommend an evolutionary approach to this development of the standard.

Recommendation: the parameter $T_{V,}$ be limited to a maximum value of 30 minutes.

There were many balloters who indicated a need to set an upper limit on T_v and the standard has been changed to include this restriction.

Public Service Company of New Hampshire PSNH

The primary objection is that this standard would now allow a Reliability Authority (RA) to define the acceptable time of violation of each IROL. We now operate with the expectation that the transmission system will be returned to within Operating Security Limits as soon as possible, but no longer than 30 minutes. Given the August 14 Blackout, how can we as an industry allow an RA to lesson this expectation?

There were many balloters who indicated a need to set an upper limit on T_v and the standard has been changed to include this restriction.

Southern Company Services SOCO (Generators)

Southern Company Services SOCO (Transmission Owners)

Please note in the excerpt below that each RA may use whatever system it wants for choosing Tv. This will certainly be an important issue along seams, especially if there is no limit for Tv.
"How do you establish a Tv for an IROL?
Each RA may use whatever system it wants for establishing a Tv for its IROLs. This gives each RA the latitude to be as conservative as it desires. Some RAs may choose to use a default Tv of 30 minutes — currently some entities have a default of 20 minutes for all limits that would be categorized as IROLs. One of the benefits of this variable Tv is that it gives an RA that operates in a market environment greater flexibility before implementing remedial actions that have the effect of negatively impacting that market."

Southern recommends a cap (maximum) for Tv of 30 minutes. The 30-minute limit is the best benchmark we have as a maximum value and should be considered as the cap unless an alternative value can be shown to be more appropriate.

There were many balloters who indicated a need to set an upper limit on T_v and the standard has been changed to include this restriction.

Some balloters indicated a concern about the need for more specific coordination of IROLs on ‘shared’ facilities. The standard was revised to include a requirement that RAs have an agreed upon process for developing IROLs for each shared Facility (or group of Facilities) subject to IROLs.

Carolina Power & Light Company CPL (Transmission Owners)
Carolina Power & Light Company CPL (LSEs)
Carolina Power & Light Company CPL (Generators)
Southern Company Services SOCO (Generators)
Southern Company Services SOCO (Transmission Owners)

By definition, all IROLs are significant and impact the reliability of the Interconnection. Therefore, the reasoning for allowing an RA the full range to determine $\underline{T_v}$ is especially bothersome. The best compromise is for the standard to set a maximum $\underline{T_v}$ and allow the RAs to set it up to that cap. In addition, although various market solutions can/should be used to manage the system in an attempt to avoid IROLs, it should not dictate or drive what $\underline{T_v}$ should be set at. $\underline{T_v}$ should be set according to the severity of the situation, not according to the least cost/least impact to the market. Once you are dealing with IROLs and into the $\underline{T_v}$ period, you are at a critical operating state. In a response to comments the SDT stated, “Including specific language that references tariffs and market issues is outside the scope of NERC’s reliability standards.”

Not only should specific language that references markets be absent, but those markets should not drive aspects of reliability standards to the detriment of reliability. The 30-minute limit contained in Policy 2 is the best benchmark we have as a maximum value and should be used as the cap.

There were many balloters who indicated a need to set an upper limit on T_v and the standard has been changed to include this restriction.

Southern Company Services SWE

For Tv related to an Interconnected Operating Reliability Limit, IROL: The Standard allows the Reliability Authority to identify the Tv for each IROL. It is recommended that the Tv time limit not be open ended but require the RA to establish a maximum time limit of 30 minutes (as current policy requires) to return to normal operating conditions. It could be less if the RA deems it necessary.

There were many balloters who indicated a need to set an upper limit on T_v and the standard has been changed to include this restriction.

Wisconsin Public Service Corporation WPS

The Tv should have a maximum time limit that coincides with the max value for SOL's.

There were many balloters who indicated a need to set an upper limit on T_v and the standard has been changed to include this restriction.

Westar Energy WR

The unlimited Tv allows an entity to set a Tv value “accepting risk” for some period of time, while neighboring entities are also exposed to the risk but are unable to limit the Tv that is defined. A variable Tv with a maximum of 30 minutes or 1 hour would be more acceptable. If more time is needed to resolve loading problems, actions should be started prior to reaching the IROL.

There were many balloters who indicated a need to set an upper limit on T_v and the standard has been changed to include this restriction.

American Transmission Company LLC ATC (Transmission Owners)

MAIN

The treatment of Tv is incomplete in a number of ways. For example, the compliance monitoring process requires a list of facilities and associated operating limits subject to IROL's but without mention of the associated Tv for each of that list's facilities (Section 201 (d) (3)). Conformance to the NERC Functional Model could be improved since the current version of the Functional Model makes the Reliability Authority responsible for determining IROL's but not specifically the time limits associated with those IROL's. Finally, the standard allows for some radical values of Tv. If Tv is set to zero, for instance, it creates the possibly unintended requirement to operate some facilities to an N-2 criterion.

The requirement and the measures already include a requirement that there be a Tv for each IROL.

There were many balloters who indicated a need to set an upper limit on T_v and the standard has been changed to include this restriction.

Western Area Power Administration - CM WACM

T sub v needs to be developed with a maximum time limit. All IROLs are significant, by definition, and should not have the latitude of an open ended requirement.

There were many balloters who indicated a need to set an upper limit on T_v and the standard has been changed to include this restriction.

Westar Energy WR (LSEs)

We feel that there shoud be a specific length of time to correct any violation. If that time is exceed, then penalties should occur. The way the rule is currently written, an entity could be violating a reliability limit for an indefinit length of time with no penalty.

There were many balloters who indicated a need to set an upper limit on T_v and the standard has been changed to include this restriction.

MAIN

Having identified the IROLs in advance there needs to be allowance for reacting to a system circumstance that has similarity to what was predefined but has some operationally significant differences in real time. e.g. there could be instances where an operator is directed to follow a predefined solution to an operating limit that may be invalid due to different circumstances that exist on the transmission system. While we are not trying to suggest that the process be burdened with debates, we believe that there should be a provision for discussions of conditions and effective actions, where time allows.

This standard doesn’t require the RAs to follow their action plans, they may adjust these plans to meet real time conditions. For IROLs that can’t be exceeded for more than a few cycles, special protection systems or remedial action schemes may be installed.

- ***Tv – Seams issues & 2nd Party Review***

Western Area Power Administration - CM WACM

One of the on-going problems that has existed from region to region, and in some cases, within sub-regions, is the development of a consistent operating limit. While the purpose of this standard is to enforce the observance of those limits, we feel that there needs to be more proscriptive wording within the standard for the creation to those limits.

The standard was revised to include a requirement that RAs have an agreed upon process for developing IROLs for each shared Facility (or group of Facilities) subject to IROLs.

Bonneville Power Administration - Power Business BPAP

201.a.2.i states that the Reliability Authority (RA) shall identify the maximum time that an Interconnected Reliability Operating Limit (IROL) can be exceeded without compliance sanctions being applied for each IROL. Presently WECC states the time limit as 20 minutes for stability and 30 minutes for thermal limitations. It should not the responsibility of each individual RA to set the time limit, but rather the responsibility of the NERC Region (or sub region at the very least). There are paths on which energy flows between different RA's areas of responsibility. There is, under the proposed wording, the possibility that two different time limits be set, one by each RA? This could lead to much confusion.

The standard was revised to include a requirement that RAs have an agreed upon process for developing IROLs for each shared Facility (or group of Facilities) subject to IROLs.

If a Region wants to establish limits that are more stringent than the NERC standard, that is acceptable without the need to revise the language in the standard. If a Region wants to establish a standard that is less restrictive than the NERC standard, then the Region must request a Regional Difference.

Allegheny Power AP

Adjoining Reliability Authorities should be allowed to review Tvs.

The standard was revised to include a requirement that RAs have an agreed upon process for developing IROLs for each shared Facility (or group of Facilities) subject to IROLs. With the next posting of this standard, the SDT will ask the industry the following question:

> Several balloters indicated a concern over coordination of IROLs between RAs. Do you think the standard should include a requirement that the RA obtain agreement from its adjacent RAs on which Facilities in the combined RA Areas are subject to IROLs?

Allegheny Power AP

Regional Councils should monitor Tvs.

The standard was revised to include a requirement that RAs have an agreed upon process for developing IROLs for each shared Facility (or group of Facilities) subject to IROLs.

If a Region wants to monitor and/or approve the Tvs of its Region, the Region may request this outside of the NERC standard. If a Region wants to require that the Tvs be submitted to the Region as part of this standard, then the Region should request a Regional Difference as part of this standard.

Ontario Power Generation Inc OPG

SECTION 201:
Tv needs to be specified and should be consistent, at least across each interconnection.

A maximum for Tv has been established.

The standard was revised to include a requirement that RAs have an agreed upon process for developing IROLs for each shared Facility (or group of Facilities) subject to IROLs. With the next posting of this standard, the SDT will ask the industry the following question:

> Several balloters indicated a concern over coordination of IROLs between RAs. Do you think the standard should include a requirement that the RA obtain agreement from its adjacent RAs on which Facilities in the combined RA Areas are subject to IROLs?

PSEG Energy Resources & Trade LLC PS

PSEG Power LLC

Public Service Electric and Gas Company (LSEs)

The RAs should be required to ensure that the facilities monitored and the physical and time limits are consistently determined within their footprint and coordinated with interconnected RAs to ensure consistency. (Section 201)

Standard 600 requires that there be a methodology used to develop SOLs that are a basis for IROLs.

The standard was revised to include a requirement that RAs have an agreed upon process for developing IROLs for each shared Facility (or group of Facilities) subject to IROLs. With the next posting of this standard, the SDT will ask the industry the following question:

> Several balloters indicated a concern over coordination of IROLs between RAs. Do you think the standard should include a requirement that the RA obtain agreement from its adjacent RAs on which Facilities in the combined RA Areas are subject to IROLs?

Reliant Resources Inc RRI

Sec 201 - There is no consistency required between Reliability Authorities as far as which flowgates are monitored, what physical limit they will be not allowed to exceed, and what time frame operating limits may be exceeded. A lack of consistency will lead to operating reliability problems as well as hinder market transactions that impact flowgates across multiple RAs.

The standard was revised to include a requirement that RAs have an agreed upon process for developing IROLs for each shared Facility (or group of Facilities) subject to IROLs. With the next posting of this standard, the SDT will ask the industry the following question:

> Several balloters indicated a concern over coordination of IROLs between RAs. Do you think the standard should include a requirement that the RA obtain agreement from its adjacent RAs on which Facilities in the combined RA Areas are subject to IROLs?

Wisconsin Energy Corporation - PM WEC

The ability of the RA to both identify and set the Tv for IROL's lends itself to a natural conflict with the compliance sanctions. The longer the Tv the more time the RA has to act to mitigate the limit violation and avoid a stronger penalty in requirement 204. Suggest that the list of IROL's and their Tv may be developed by the RA but must be confirmed by the Planning Authority if not the same entity, or the RA's Regional Reliability Council. For RA's with dynamic or automated determination of IROL's and their Tv conformation of the criteria and methodology by the PA if not the same entity or the RA's RRC. Confirmation by a third party may ensure that the RA will not put the interconnection in undue risk.

T_v has been revised so that it can't exceed 30 minutes.

The standard was revised to include a requirement that RAs have an agreed upon process for developing IROLs for each shared Facility (or group of Facilities) subject to IROLs.

With the next posting of this standard, the SDT will ask the industry the following question:

> Several balloters indicated a concern over coordination of IROLs between RAs. Do you think the standard should include a requirement that the RA obtain agreement from its adjacent RAs on which Facilities in the combined RA Areas are subject to IROLs?

Electricity Consumers Resource Council

Section 201 does not require consistency between RA's regarding the monitoring of flow gates. A lack of consistency will lead to reliability problems and must be resolved.

The standard was revised to include a requirement that RAs have an agreed upon process for developing IROLs for each shared Facility (or group of Facilities) subject to IROLs. With the next posting of this standard, the SDT will ask the industry the following question:

> Several balloters indicated a concern over coordination of IROLs between RAs. Do you think the standard should include a requirement that the RA obtain agreement from its adjacent RAs on which Facilities in the combined RA Areas are subject to IROLs?

City of Lakeland PLKT

STD does not address seams issues and how the RA interacts with other RA's when seams problems arise

The standard was revised to include a requirement that RAs have an agreed upon process for developing IROLs for each shared Facility (or group of Facilities) subject to IROLs. With the next posting of this standard, the SDT will ask the industry the following question:

> Several balloters indicated a concern over coordination of IROLs between RAs. Do you think the standard should include a requirement that the RA obtain agreement from its adjacent RAs on which Facilities in the combined RA Areas are subject to IROLs?

Consumers Energy CETR (TDUs)

Consumers Energy votes against this proposed standard because it fails to establish specific Interconnection Reliability Operating Limit measures and specific Tv values for those measures. Further it leaves the development of such measures to each Reliability Authority, thus potentially causing significant differences in compliance requirements between control areas without a workable mechanism to come to concensus on the appropriate measures and Tv values.

The standard was revised to include a requirement that RAs have an agreed upon process for developing IROLs for each shared Facility (or group of Facilities) subject to IROLs. With the next posting of this standard, the SDT will ask the industry the following question:

> Several balloters indicated a concern over coordination of IROLs between RAs. Do you think the standard should include a requirement that the RA obtain agreement from its adjacent RAs on which Facilities in the combined RA Areas are subject to IROLs?

Minnesota Power MP

In the MAPP region, the North Dakota and Manitoba to USA flowgates can be constrained by either thermal limits or stability limits. How could proposed standard 200 be approved for the stability attributes of these flowgates, without consideration of how the thermal attributes of these flowgates will be administered?

The standard was revised to include a requirement that RAs have an agreed upon process for developing IROLs for each shared Facility (or group of Facilities) subject to IROLs.

Thermal limits and stability limits can be IROLs if operating outside of these limits could lead to instability, cascading outages or uncontrolled separation that adversely impacts the interconnection. If operating outside of these limits does not lead to instability, cascading outages or uncontrolled separation, then these limits are not IROLs.

- ***Add a link to the DFR Standard***

Carolina Power & Light Company CPL (Transmission Owners)
Carolina Power & Light Company CPL (LSEs)
Carolina Power & Light Company CPL (Generators)

There needs to be additional verbiage in Standard 200 linking it to the Determine Facility Ratings Standard's methodology for establishing limits.

The following footnote has been added to the standard.

> Each IROL is a system operating limit established by following the methodology established in the "Determine Facility Ratings, System Operating Limits and Transfer Capabilities" standard. IROLs are the subset of system operating limits that, if exceeded, may cause instability, uncontrolled separation or cascading outages. Each IROL has both a magnitude and a duration component. The duration component may be different for each IROL and may be as short as '0' minutes or as long as 30 minutes.

Bonneville Power Administration Transmission BPAT

The term "system operating limit" is used in the definition of the Interconnection Reliability Operating Limit (IROL) but it is not defined in this standard nor is there a reference that it is as defined in the proposed Standard 600, "Determine Facility Ratings, System operating Limits, and Transfer Capabilities". In Standard 200 there should be a clear understanding that the IROL is a subset of a "System Operating Limit" as defined in the proposed Standard 600.

The definitions developed by drafting teams are not intended to be unique to each standard. Each definition that is accepted by the industry will be entered into a common database and used by all drafting teams.

The following footnote has been added to the standard.

> Each IROL is a system operating limit established by following the methodology established in the "Determine Facility Ratings, System Operating Limits and Transfer Capabilities" standard. IROLs are the subset of system operating limits that, if exceeded, may cause instability, uncontrolled separation or cascading outages. Each IROL has both a magnitude and a duration component. The duration component may be different for each IROL and may be as short as '0' minutes or as long as 30 minutes.

Entergy EES (Transmission Owners)

At this time it appears the Determine Facility Ratings standard may provide for some coordination by stating that RAs, PAs, and TOPs will establish system operating limits for the areas for which they are responsible. However, this Operate Within IROL standard requires the RA to determine SOLs and then decide which of those will be used as IROLs, completely independent of, and not coordinated with the Determine Facility Rating standard requirements. These two standards must be coordinated. The IROLs used by the RAs in this standard must be a subset of the SOLs developed jointly under the Determine Facility Rating standard.

The following footnote has been added to this standard.

> Each IROL is a system operating limit established by following the methodology established in the “Determine Facility Ratings, System Operating Limits and Transfer Capabilities” standard. IROLs are the subset of system operating limits that, if exceeded, may cause instability, uncontrolled separation or cascading outages. Each IROL has both a magnitude and a duration component. The duration component may be different for each IROL and may be as short as ‘0’ minutes or as long as 30 minutes.

The Determine Facility Ratings, System Operating Limits and Transfer Capabilities Standard does not require that System Operating Limits be developed jointly. The Determine Facility Ratings Standard requires that the RA develop System Operating Limits for its Reliability Area.

Southern Company Services SOCO (Generators)
Southern Company Services SOCO (Transmission Owners)
Georgia Power Company (LSEs)

The concept of operating to first contingency seems lost except where it is covered in the Determine Facility Ratings Standard. The idea that you are trying to protect for these circumstances should at least be mentioned in Standard 200. Southern thinks there should be additional verbiage in Standard 200 linking to the Determine Facility Ratings Standard’s methodology for establishing limits.
The following footnote has been added to this standard.

> Each IROL is a system operating limit established by following the methodology established in the “Determine Facility Ratings, System Operating Limits and Transfer Capabilities” standard. IROLs are the subset of system operating limits that, if exceeded, may cause instability, uncontrolled separation or cascading outages. Each IROL has both a magnitude and a duration component. The duration component may be different for each IROL and may be as short as ‘0’ minutes or as long as 30 minutes.

Carolina Power & Light Company CPL (Transmission Owners)
Carolina Power & Light Company CPL (LSEs)
Carolina Power & Light Company CPL (Generators)

The concept of operating to first contingency seems to have been lost in the development of this standard. It is a core precept of reliable operations and should be included in this standard.

The concept of operating to first contingency is addressed in the Determine Facility Ratings Standard’s requirement for developing a methodology for System Operating Limits.

The following footnote has been added to the IROL Identification Requirement of this standard to clarify that IROLs are a subset of the System Operating Limits developed under the Determine Facility Ratings standard.

> Each IROL is a system operating limit established by following the methodology established in the "Determine Facility Ratings, System Operating Limits and Transfer Capabilities" standard. IROLs are the subset of system operating limits that, if exceeded, may cause instability, uncontrolled separation or cascading outages. Each IROL has both a magnitude and a duration component. The duration component may be different for each IROL and may be as short as '0' minutes or as long as 30 minutes.

PSEG Energy Resources & Trade LLC PS
PSEG Power LLC
Public Service Electric and Gas Company (LSEs)

Whatever emergency ratings are implemented by the RA, e.g., 24-hour, 4-hour, 30-minute, etc., the RA must possess the ability to relieve actual post-contingency overloads to acceptable levels within the time limit allowed by the particular rating invoked. (Section 201)

This standard has been revised so that T_v cannot exceed 30 minutes.

- ***Add a requirement to share or post limits***

Reliant Resources Inc RRI

Sec 201 - There is no requirement to make the operating limits and time limits available to transmission users. Such information provides transparency to the market.

This standard is limited to addressing reliability issues. With the next posting of this standard, the SDT will ask the industry the following question:

> Several balloters requested that the SDT change the standard to include a requirement that RAs publicly post their IROLs. The SDT could not identify a reliability-related reason to support this. Do you want the standard to require public posting of IROLs?

Public Service Electric and Gas Company (Trans owners)

The present language of the Standard proposed for Ballot must be modifed to include the following issue
The RA must publically post the Operating Limits and time limits for all facilities under their jurisdiction.

The SDT is unaware of any reliability – related reason for posting operating limits. Some of these IROLs may be very dynamic and may change multiple times over the course of a day. Asking all RAs to post these without a reliability-related reason is beyond the scope of the SDT. If you are aware of a reliability reason for posting these limits, please submit the reason on the next posting. Keep in mind that an RA may request data from another RA if the data is needed to support reliability. Not all RAs are TSPs and some RAs will not have access to OASIS.

With the next posting of this standard, the SDT will ask the industry the following question:

> Several balloters requested that the SDT change the standard to include a requirement that RAs publicly post their IROLs. The SDT could not identify a reliability-related reason to support this. Do you want the standard to require public posting of IROLs?

PSEG Energy Resources & Trade LLC PS

PSEG Power LLC

Public Service Electric and Gas Company (LSEs)

In the interest of transparency of operating requirements, a provision requiring that the RA publicly and timely post the operating limits and time limits for every facility for which they have established such must be added. Such posting should be made on each OASIS covering any portion of the RA's footprint. (Section 201)

The SDT is unaware of any reliability – related reason for posting operating limits. Some of these IROLs may be very dynamic and may change multiple times over the course of a day. Asking all RAs to post these without a reliability-related reason is beyond the scope of the SDT. If you are aware of a reliability reason for posting these limits, please submit the reason on the next posting. Keep in mind that an RA may request data from another RA if the data is needed to support reliability. Not all RAs are TSPs and some RAs will not have access to OASIS.

With the next posting of this standard, the SDT will ask the industry the following question:

> Several balloters requested that the SDT change the standard to include a requirement that RAs publicly post their IROLs. The SDT could not identify a reliability-related reason to support this. Do you want the standard to require public posting of IROLs?

Mirant Americas Energy Marketing LP MAEM

Under Section 201, would like to see a requirement that the RA reveal the list of IROLs and facilities impacted by said IROLs, at a minimum to all RAs (possibly publicly available, but I'm not sure that's the right thing to do) in the relevant interconnection. This would enable necessary coordination of action plans.

The Coordinate Operations standard requires that each RA provide requested data to another RA if there is a reliability-related reason for the request. Publicly posting the data seems to be asking the RA to expend resources that may not be needed to support reliability. With the next posting of this standard, the SDT will ask the industry the following question:

> Several balloters requested that the SDT change the standard to include a requirement that RAs publicly post their IROLs. The SDT could not identify a reliability-related reason to support this. Do you want the standard to require public posting of IROLs?

Ontario Power Generation Inc OPG

SECTION 201:
Reliability Authorities should be obligated to publish, for market participant use, the list of facilities which they are monitoring and the limits on those facilities. In part, this will insure appropriate coordination between adjacent RAs.
This standard is limited to addressing reliability issues.

The standard was revised to include a requirement that RAs have an agreed upon process for developing IROLs for each shared Facility (or group of Facilities) subject to IROLs.

With the next posting of this standard, the SDT will ask the industry the following question:

> Several balloters requested that the SDT change the standard to include a requirement that RAs publicly post their IROLs. The SDT could not identify a reliability-related reason to support this. Do you want the standard to require public posting of IROLs?

- ***Add language indicating IROLs can by dynamic***

Power Pool of Alberta PPOA

Standard 200 should be changed to clearly reflect th fact that IROLs can be dynamic in nature.

One of the measures for requirement 201 was revised so that the RA must be able to demonstrate that it can identify its current Interconnection Reliability Operating Limits. This switch from having a 'list' should clarify that the IROLs may be dynamic.

Carolina Power & Light Company CPL (Transmission Owners)

Carolina Power & Light Company CPL (LSEs)

Carolina Power & Light Company CPL (Generators)

The list of IROLs is a dynamic list. Standard 200 needs clear verbiage noting the dynamic nature of this list. In addition, the standard should not imply that if the limit is not on the list that you don't have to operate to it. The not-previously-identified events that would place you in an IROL should have the same requirements as those already on the list.

One of the measures for requirement 201 was revised so that the RA must be able to demonstrate that it can identify its current Interconnection Reliability Operating Limits. This switch from having a 'list' should clarify that the IROLs may be dynamic.

National Grid USA

New Brunswick Power Corporation NBPC

New York Power Authority NYPA

Niagara Mohawk NMPC

New York Power Authority MED

Northeast Utilities NU

Nova Scotia Power NSPI

Ontario - Independent Electricity Market Operator IMO

Hydro One Networks Inc (LSEs)

Hydro-Quebec HQT

It is National Grid's (NPCC's) (ISO New England) (Hydro Quebec HQT) position that Standard 200 should clearly reflect the fact that IROL's can be dynamic in nature. While it may be possible that every possible configuration can be identified in advance to deal with this dynamics, the reality is that this list would be extremely large and difficult to maintain. To improve on the situation, this section should require that the RA operators have a base set of limits that include N-1 configurations, along with identifying the following:

- The boundary conditions for which the published limits are applicable;
- The critical contingency that drive the applicable limit; and
- An understanding of what the associated limit is designed to protect the system against (i.e. transient stability, voltage decline, etc.)

One of the measures for requirement 201 was revised so that the RA must be able to demonstrate that it can identify its current Interconnection Reliability Operating Limits. This switch from having a 'list' should clarify that the IROLs may be dynamic.

With the next posting of this standard, the SDT will ask the industry the following question:

> Several balloters recommended the following addition to this requirement. Do you agree with this addition?

> (i) The RA shall provide the following information to its system operators:
> (a) The system conditions under which the Interconnection Reliability Operating Limit applies,
> (b) The contingency that is the basis for the limit,
> (c) The impact of exceeding the limit

NPCC

New York Power Authority MED

Northeast Utilities NU

LIPA LIPA (Transmission Owners)

Standard 200 should reflect the fact that IROLs can be dynamic in nature. RAs should have a base set of limits that include N-1 configurations, along with identifying the following:

- The boundary conditions for which the published limits are applicable;
- The critical contingency that drives the applicable limit; and
- An understanding of what the associated limit is designed to protect the system against (i.e. transient stability, voltage decline, etc.)

One of the measures for requirement 201 was revised so that the RA must be able to demonstrate that it can identify its current Interconnection Reliability Operating Limits. This switch from having a 'list' should clarify that the IROLs may be dynamic.
With the next posting of this standard, the SDT will ask the industry the following question:

> Several balloters recommended the following addition to this requirement. Do you agree with this addition?

> (i) The RA shall provide the following information to its system operators:
> (a) The system conditions under which the Interconnection Reliability Operating Limit applies,
> (b) The contingency that is the basis for the limit,
> (c) The impact of exceeding the limit

- ***Add requirement to study area beyond RA's perimeter***

Hydro One Networks Inc (LSEs)

The Standard does not include clear definitions or criteria on how "local" and "Wide Area Impact" events are determined. Therefore, it is difficult to assess what electrical boundaries an IROL is meant to protect. The definition of Wide Area Impact points out that the electrical area to be included in the limit may be larger than the portion of the transmission system under the authority of a single Reliability Authority (RA). This indicates the need for studies and associated limits that transcend the boundaries of a single RA's purview, yet there is no formal statement identifying this need in standard, 200, 600 or the Co-ordinate Operations Standard (currently under development).

The definitions provided with this standard have been revised to improve the industry's understanding of the applicability of these terms to this standard. Note that the terms, 'local area' and 'wide area impact' are not used in this standard.

Wide Area Impact: ~~The impact of an event that, if left untended, could lead to voltage instability, cascading outages or uncontrolled separation that jeopardizes the reliability of an interconnection. The geographic size of the area affected by such an event is always larger than the local area monitored by a single transmission operator and may also be larger than a single Reliability Authority's area.~~

The impact of a single incident resulting in uncontrolled loss of 300 MW or more of networked system load for a minimum of 15 minutes.

Cascading Outages: The uncontrolled successive loss of system elements triggered by an incident at any location that results in the loss of 300 MW or more of networked system load for a minimum of 15 minutes

Bulk Electric System: A term commonly applied to the portion of an electric utility system that encompasses the electrical generation resources and ~~bulk~~ high voltage transmission system (above 35 kV or as approved in a tariff filed with FERC).

Operating within IROLs should prevent instability, cascading outages and uncontrolled separation.

South Carolina Electric & Gas Company SCEG

This standard places a lot of emphasis on IROLs, however, no guidelines on how to determine an operating limit have yet been determined. It goes further by allowing an arbitrary 30 minute time limit – why not 15, 5, or 0 minutes? Some limits cannot be surpassed by 15 minutes, yet the standard allows for it. In another respect, some limits can be exceeded for far more that 30 minutes depending on the situation, but the standard ignores that. I know this standard is not meant to define limits, but how can one be expect to agree to its requirements until the definition of limits is better defined?

The definitions provided with the standard have been revised to assist in interpreting the applicability of this standard. The standard was revised, based on the numerous comments submitted by balloters, to indicate that T_v may not exceed 30 minutes.

NPCC
New York Power Authority MED
Northeast Utilities NU
LIPA LIPA (Transmission Owners)

The Standard should establish criteria on how "local" and "Wide Area Impact" are determined. The definition of Wide Area Impact in the standard cites that the electrical area to be included may be larger than a single RA. This indicates the need for studies and associated IROLs that transcend the boundaries of a single RA's purview, yet there is no statement identifying this need in the standard.

The definitions provided with the standard have been revised to assist in interpreting the applicability of this standard.

National Grid USA
New Brunswick Power Corporation NBPC
New York Power Authority NYPA
Niagara Mohawk NMPC
New York Power Authority MED
Northeast Utilities NU
Nova Scotia Power NSPI
Ontario - Independent Electricity Market Operator IMO
United Illuminating UICO
Hydro-Quebec HQT

The Standard does not include clear definitions or criteria on how “local” and “Wide Area Impact” are determined. Therefore, it is difficult to assess what electrical boundaries an IROL is meant to protect. This definition of Wide Area Impact points out that the electrical area to be included in the limit may be larger than the portion of the transmission system under the authority of a single Reliability Authority (RA). This indicates the need for studies and associated limits that transcend the boundaries of a single RA's purview, yet there is no formal statement identifying this need in standard, 200, 600 or the Co-ordinate Operations Standard (currently under development).

The definitions provided with the standard have been revised to assist in interpreting the applicability of this standard. The standard was revised, based on the numerous comments submitted by balloters, to indicate that T_v may not exceed 30 minutes.

FirstEnergy Corp

A fundamental problem is that it is difficult to determine what facility could be a potential IROL before the fact. The proposed document gives little guidance. In section 201, IROL Identification, the requirements simply state the Reliability Authority shall identify what facilities are subject to IROL, with no real guidance on how to do it. This leaves it up to the Reliability Authority to document how they will determine their IROLs, and then if anything goes wrong they will be second guessed that they did not do it right. If the Reliability Authority takes the extreme position and 'over' specify facilities as potential IROLs, they will cover themselves for any second guessing, but operate the system in a potentially overly conservative manner.

The definitions provided with the standard have been revised to assist in interpreting the applicability of this standard.

MAIN

The standard is not precise enough in defining where it should be applied. More specifically, the standard asks Reliability Authorities to designate facilities to be subject to IROL's, as distinct from SOL's, presumably on the basis of potential "Wide Area Impact," but the meaning of "Wide Area" remains an open question. For example, it remains undetermined whether the largest city or

even some multi-state regions would meet the definition of "Wide Area."
The definitions provided with the standard have been revised to assist in interpreting the applicability of this standard.

Measures

(b) Measures

(1) The Reliability Authority shall have a list of Facilities (or groups of Facilities) in its ~~the Reliability Authority's~~ Reliability Authority Area that are subject to Interconnection Reliability Operating Limits.

(i) The Reliability Authority shall have evidence it has reviewed~~s~~ and updated~~s~~ ~~the~~ its ~~-~~list of Facilities (or groups of Facilities) to reflect changes in its Reliability Authority Area's system topology.

(2) The Reliability Authority shall be able to identify the current values of the Interconnection Reliability Operating Limits for its Reliability Authority Area. Each of these Interconnection Reliability Operating Limits shall have a T_v that is smaller than or equal to 30 minutes.

(iii) The Reliability Authorities that share a Facility (or group of Facilities) shall have an agreed upon process for determining if that Facility (or group of Facilities) is subject to an Interconnection Reliability Operating Limit and for determining the value of that Interconnection Reliability Operating Limit and its associated T_v.

(3) The Reliability Authority shall ~~have evidence that it updates the list of~~ be able to demonstrate that its Interconnection Reliability Operating Limit values and their T_v ~~to~~ reflect current system conditions.

Summary Consideration:

The measures were revised to conform to the changes requested in the associated requirements, specifically to add a requirement that addresses shared facilities and to modify the requirement so that the dynamic nature of IROLs is recognized.

Manitoba Hydro Electric Board MHEB (Electricity Brokers, Aggregators, and Marketers)

Manitoba Hydro MHEB (LSEs)

Manitoba Hydro (Transmission Owners)

The need for all system conditions to be studied as they occur should be emphasized. Statement 201 b.3 should be expanded to state that the limits and the mitigation steps must BOTH be reviewed and revised, if required, to reflect all changes in current conditions. This need could also be identified in 203 b.1.ii (i.e., an assessment must be followed by revision of limits and guides if conditions warrant)

The measures were revised to indicate that the RA must be able to demonstrate that the IROls reflect current system conditions. This supports your suggestion.

Compliance Monitoring

Bonneville Power Administration Transmission BPAT

Section 201.d.2 states that the “Performance reset period shall be 12 months from the last violation”. I assume that this is per each IROL (or rated path), but there is no further information. Are the facilities/IROLs grouped into one for the reset period or is there a separate reset period for each facility/IROL?

The levels of non-compliance are based on not meeting the individual measures within a requirement. A violation occurs whenever a measure in the requirement has not been met. Each violation is considered a separate occurrence – and each successive violation would result in an increasingly more severe penalty. To reset the accumulation of occurrences, (end of the performance reset period) the RA needs to go 12 months without any violations.

The way the performance reset period works, performance is measured over the course of a 12 month period of time. If there is any violation during this time, then the performance reset period would not reset.

Levels of Non-compliance

(e) Levels of Noncompliance

(1) Level one: ~~Not applicable~~ No process for determining if shared Facilities (or groups of Facilities) are subject to Interconnection Reliability Operating Limits and for determining the value of that Interconnection Reliability Operating Limit and its associated T_v.

(2) Level two: ~~Not applicable~~ No evidence that a shared Facility (or group of Facilities) has an Interconnection Reliability Operating Limit with a T_v that has been agreed to by all Reliability Authorities that share the Facility (or group of Facilities).

(3) Level three: A level three noncompliance occurs if either of the following conditions are present:

(i) One or more Interconnection Reliability Operating Limits had a T_v that was greater than 30 minutes.

(ii) No evidence that ~~Either the list of Interconnection Reliability Operating Limits or~~ the list of Facilities subject to Interconnection Reliability Operating Limits was ~~not~~ updated.

(4) Level four: A level four noncompliance occurs if either of the following conditions are present:

(i) Could not identify the current values of the IROLs for its Reliability Area

(ii) No list of ~~Interconnection Reliability Operating Limits or no list of~~ Facilities subject to Interconnection Reliability Operating Limits exists for the ~~Reliability Authority's~~

AEP Service Corp -- Transmission System AEP
Oklahoma Gas and Electric OKGE

The SDT needs to revisit the levels of non-compliance associated with this standard. If compliance is truly a black/white issue with no shades of gray as the proposed levels indicate, why not have just a level one with no financial penalty? The proposed non-compliance level implies that it may be more important to have a list of IROLs rather than a correct list of IROLs. Also, if no IROLs exist, there will be no list which would cause the reliability authority to be in non-compliant. There needs to be consistency throughout all the standards on documentation-type non-compliance.

This requirement was revised and its levels of non-compliance were also revised to address the elements that were added to the standard based on balloters comments.

202 Monitoring

Requirements

Public Service Electric and Gas Company

The present language of the Standard proposed for Ballot must be modifed to include the following issue
The RA is required to ensure that all facilities monitored within their area of responsibility are consistently determined and shared with adjacent RAs.

There is another requirement in this standard that requires each RA to develop a specification for data needed to support Real-time Monitoring, Operational Planning Analyses, and Real-time Assessments. The data specification should address this concern.

The Coordinate Operations Standard addresses sharing data and information between RAs.

Measures

(b) Measures

(1) The Reliability Authority shall have a list of Facilities (or groups of Facilities) subject to Interconnection Reliability Operating Limits and shall have Interconnection Reliability Operating Limits available for its operations personnel's Real-time use.

(2) The Reliability Authority shall have Real-time Data available in a form that system operators can compare to the Interconnection Reliability Operating Limits.

(3) The Reliability Authority shall monitor system operating parameters and compare these against its Interconnection Reliability Operating Limits.

Southern Company Services SOCO (Generators)
Southern Company Services SOCO (Transmission Owners)
Georgia Power Company (LSEs)

The standard still seems to indicate a somewhat static list of IROLs. The SDT added a few words about the list having to be updated, but did not adequately address some other issues:

> "What happens if you identify another (unexpected) limit during real-time that is not on the list? Are you not responsible for this case as well? We all know that planning studies cannot predict all the challenges that are faced in real-time."

The list of IROLs is a dynamic list. Standard 200 needs clear verbiage noting the dynamic nature of this list. In addition, the standard should not imply that if the limit is not on the list that you don't have to operate to it. The not-previously-identified events that would place you in an IROL should have the same requirements as those already on the list. In section 203, part b, "identified" should be removed from the last part of the sentence:

> "The Reliability Authority shall identify operating situations or events that impact its Reliability Authority Area's ability to operate without exceeding any ~~identified~~ Interconnection Reliability Operating Limits."

One of the measures for requirement 201 was revised so that the RA must be able to demonstrate that it can identify its current Interconnection Reliability Operating Limits. This switch from having a 'list' should clarify that the IROLs may be dynamic. Your suggestion to remove the word, 'identified' was adopted and is reflected in the revised standard.

Bonneville Power Administration Transmission BPAT

In Section 202(b)(3), the standard indicates that the RA shall monitor "system operating parameters" which is an undefined term. It is unclear why the RA would need any information not included in the IROL to monitor the system. More explanation of what system operating parameters include is needed and how this information is different from the information in the IROL. It is recommended that "System Operating Parameters" be defined in the "Definition" section of the Standard and that it include something similar to "variables that impact the IROL".

Most industry commenters agreed with the original language in this requirement.

If the SDT defines system operating parameters, then readers may interpret the requirement to mean that IROLS should be limited to the listed parameters, and this isn't the intent. The standard only addresses the system operating parameters associated with the IROLs.

Levels of Non-compliance

AEP Service Corp -- Transmission System AEP
Oklahoma Gas and Electric OKGE

Again the issue of degrees of non-compliance surfaces. Are there shades of gray with non-compliance for this standard or is it strictly a black and white issue? Why jump directly to level four non-compliance? Is progressive non-compliance not an option? For example, if a reliability authority had identified 25 IROLs, he is level four non-compliant if only one of the IROLs is not available for real-time use. Shouldn't there be allowances for such situations? Also, perhaps a letter that lists critical displays and identifies discrepancies would be more beneficial to maintaining interconnection reliability than a monetary penalty.

Due to the severity of IROL violations, not being aware of one IROL is unacceptable.

Kansas City Power & Light KCPL

Question if compliance differiates between telemetered and not telemetered but should

The definition of Real-time data allows for data to be collected manually – so there isn't a need to differentiate between telemetered and non-telemetered data.

203 Analyses and Assessments

Requirements

Manitoba Hydro Electric Board MHEB (Electricity Brokers, Aggregators, and Marketers)

Manitoba Hydro (Transmission Owners)

The requirement to perform Operational Planning Analysis or the Real-time Assessment in standard 203 a should be more clearly defined. A methodology including any restrictions on or recommendations for how to perform these activities should be included in this standard.

The RA Certification Standard is expected to include a requirement that the RA have a process or procedure in place that identifies how it will perform its Operational Planning analyses and Real-time assessments. Each RA may have different tools and different operating constraints, and establishing a methodology that would be applicable to all RAs is more restrictive than necessary to support reliability.

City of Tallahassee TAL

How far out is the Real-time Assessment supposed to look? Only 30 minutes since it is run at least every 30 minutes, or up to the day ahead since a day ahead look is done at least every day. What is meant by "expected"? First contingency?

Real-time assessments look at real time information as well as future information. The RA needs to make a judgment about how far ahead the real-time assessment should look, based on its specific operating conditions.

The Operational Planning Analysis is conducted each day to look at the day ahead. The definition of Operational Planning Analysis has been modified to clarify that an operational planning analysis may look for the next day's operation up to 12 month's ahead. This standard only addresses the Operational Planning Analysis that is done to look at the day ahead with respect to operation without violating any IROLs.

Measures

> **(b) Measures**
>
> (1) The Reliability Authority shall identify operating situations or events that impact its Reliability Authority Area's ability to operate without exceeding any ~~identified~~ Interconnection Reliability Operating Limits.
>
> (i) The Reliability Authority shall conduct an Operational Planning Analysis at least once each day, evaluating the next day's projected system operating conditions.
>
> (ii) The Reliability Authority shall conduct a Real-time Assessment periodically, but at least once every 30 minutes.

Gainesville Regional Utilities GVL (Generators)

The second point as to when Contingency analysis needs to be run. The requirement says a requirement of 30 minutes. I believe this is should be executed as needed without the requirement of 30 minutes.

The analysis should be conducted whenever needed, but must be conducted at least every 30 minutes.

AEP Service Corp -- Transmission System AEP
Oklahoma Gas and Electric OKGE

The proposed measures may be too weak. For example, it appears that a reliability authority could satisfy the operational planning analysis by evaluating an invalid case for a given day. While it meets the letter of the measure, it doesn't meet the intent of the measure. Also, does (b)(1)(ii) apply to IROLs that are associated with stability limits? If so, this measure would require a reliability authority to run real-time stability analyses every 30 minutes.

An RA that deliberately uses an invalid case is jeopardizing the reliability of its system as well as the interconnection and faces lawsuits and other public sanctions that are greater than any sanction associated with non-compliance with this standard.

The real-time assessment doesn't have to be a 'study'. The definition is: An examination of existing and expected system conditions, conducted by collecting and reviewing immediately available data.

The levels of non-compliance don't link sanctions to value judgments about the quality of assessments.

Power Pool of Alberta PPOA

we see a requirement to enhance Section 203 (b), Measures, Analyses and Assessments. Measures (1)(i) as stated require "... an operating planning analysis [be conducted] at least once each day, evaluating th next day's projected system operating conditions". We propose that a review of the next day's projected system operating conditions, against a pre-described set of operating conditions that governs IROLs, conducted at least once each day, should be considered an alternative to the above measure.

The suggested addition seems to be more of a definition of what is already understood to be done as part of the operational planning analysis and doesn't really add to the clarity of the standard.

Southern Company Services SOCO (Generators)

Southern Company Services SOCO (Transmission Owners)

The list of IROLs is a dynamic list. Standard 200 needs clear verbiage noting the dynamic nature of this list. In addition, the standard should not imply that if the limit is not on the list that you don't have to operate to it. The not-previously-identified events that would place you in an IROL should have the same requirements as those already on the list. In section 203, part b, "identified" should be removed from the last part of the sentence: "The Reliability Authority shall identify operating situations or events that impact its Reliability Authority Area's ability to operate without exceeding any Interconnection Reliability Operating Limits."
The standard has been modified to clarify that system operators must be provided a current list of facilities subject to IROLs must be able to show its current Interconnection Reliability Operating Limits and must have IROLs available for its operations personnel's Real-time use.

While the list of facilities subject to IROLs is expected to be static, IROLs are expected to be dynamic. As soon as an IROL is identified, the system operators must begin monitoring parameters against those IROLs. This supports the industry's concern that the standard be changed to recognize that IROLs can be dynamic.

Levels of Non-compliance

AEP Service Corp -- Transmission System AEP

Oklahoma Gas and Electric OKGE

Again the issue of degrees of non-compliance surfaces. Are there shades of gray with non-compliance for this standard or is it strictly a black and white issue? Why jump directly to level three non-compliance? Is progressive non-compliance not an option? Is missing an operational planning assessment one day in a month as detrimental as missing it 10-15 days per month? Similarly, is missing one real-time assessment as bad for reliability as missing these assessments for hours, on a regular basis?

For this requirement, missing one assessment may be as bad as missing many assessments.

Kansas City Power & Light KCPL

Is missing one assessment as bad as missing assessments for a period of time?

For this requirement, missing one assessment may be as bad as missing many assessments.

204 Actions

Requirements

(a) Requirements

(1) The Reliability Authority shall, without delay, act[1] or direct others to act to:

(i) Prevent instances where Interconnection Reliability Operating Limits may be exceeded.

(ii) Mitigate the magnitude and duration of instances where Interconnection Reliability Operating Limits have been exceeded.

The Reliability Authority shall document instances of exceeding Interconnection Reliability Operating Limits and shall document and complete an Interconnection Reliability Operating Limit Violation Report for instances of exceeding Interconnection Reliability Operating Limits for time greater than T_v.

- ***Add the phrase, 'Act Immediately' – or 'Prudently'***

ISO New England Inc ISNE

Standard 200 should clearly reflect requirements and measures that require all Reliability Authorities to initiate immediate corrective actions as soon as an Interconnection Reliability Operating Limit (IROL) is exceeded or the system is in an unanalyzed state. It is NPCC's position that NERC Standards should ensure mitigating actions are implemented when instability, uncontrolled separation, or cascading outages would occur as a result of a change in one or more operating parameter(s) as soon as the condition exists.

The standard has been revised to add the phrase, 'without delay' to indicate that actions should be taken ASAP.

NPCC

New York Power Authority MED

Northeast Utilities NU

LIPA LIPA (Transmission Owners)

Standard 200 should require all Reliability Authorities (RAs) to initiate *immediate* corrective actions *as soon as* the system is in an unanalyzed state or an IROL is exceeded ($T=0^+$).

The standard has been revised to add the phrase, 'without delay' to indicate that actions should be taken ASAP.

Requiring that system operators take actions when their system is in an unanalyzed state is beyond the scope of this standard.

Power Pool of Alberta PPOA

Standard 200 should be changed to require that: corrective actions be taken immediately once an Interconnection Reliability Operating Limit (IROL) is exceeded, and the parameter Tv, the time an Interconnection Reliability Operating Limit can be exceeded without compliance sanctions being applied, be limited to a maximum value of 30 minutes

The standard has been revised to add the phrase, ‘without delay’ to indicate that actions should be taken ASAP. The standard has also been revised to indicate that T_v may not be greater than 30 minutes.

Hydro-Quebec HQT

Standard 200 should clearly reflect requirements and measures that require all Reliability Authorities to initiate immediate corrective actions as soon as an Interconnection Reliability Operating Limit (IROL) is exceeded or the system is in an unanalyzed state.

The standard has been revised to add the phrase, ‘without delay’ to indicate that actions should be taken ASAP.

Requiring that system operators take actions when their system is in an unanalyzed state is beyond the scope of this standard.

United States Bureau of Reclamation

It also appears that more focus is needed on assuring that operators take timely and appropriate actions to correct any violations of operating limits.

The standard has been revised to add the phrase, ‘without delay’ to indicate that actions should be taken ASAP.

MAIN

There is no specific language stating operators should begin to take action immediately to rectify the limit violation.

The standard has been revised to add the phrase, ‘without delay’ to indicate that actions should be taken ASAP.

MAAC

I agree with commenters who suggest that there should be a 30 minute maximum limit to Tv, the "at risk" interval, and with the obligation that action should be initiated as soon as possible after recognition that a limit has been exceeded. I don't think that these are reasons enough to vote no, but would support them as additions to the standard.

The standard has been revised to add the phrase, ‘without delay’ to indicate that actions should be taken ASAP.

The standard has also been revised to indicate that T_v may not be greater than 30 minutes.

Manitoba Hydro Electric Board MHEB (Electricity Brokers, Aggregators, and Marketers)

Manitoba Hydro MHEB (LSEs)
Manitoba Hydro (Transmission Owners)

Standard 200 must be revised with a clearer statement that action is required in a timely manner. This requirement should be included in standard 204 a.1.

The standard has been revised to add the phrase, 'without delay' to indicate that actions should be taken ASAP.

Hydro One Networks Inc (LSEs)

The Standard should contain clear requirements and measures to call for immediate action on the part of Reliability Authorities to initiate corrective actions as soon as an IROL is exceeded or the system enters into an unanalyzed operating state. Hydro One Networks' position is that mitigating corrective actions must be initiated as soon as the condition exists.

The standard has been revised to add the phrase, 'without delay' to indicate that actions should be taken ASAP.

Requiring that system operators take actions when their system is in an unanalyzed state is beyond the scope of this standard.

NYISO
Ontario - Independent Electricity Market Operator IMO
ISO New England

The Standard 200 does not carry forward the current NERC Policy obligation to initiate action "as soon as possible" to restore system operation to a secure state. Our concern is that the introduction of compliance to standards must not diminish what has become accepted practice among large and sophisticated system operators to initiate actions as soon as possible to reduce the 'at risk' interval. The possible difficulties in implementing such a measure are understood, but we believe this change to the standard is necessary and achievable.

Recommendation: corrective action to be taken as soon as possible once an Interconnection Reliability Operating Limit (IROL) is exceeded.

The focus of this standard is on preventing an incident of exceeding an IROL, not just to take action after an IROL has been exceeded, which is the focus of Policy 2. The standard has been revised to add the phrase, 'without delay' to indicate that actions should be taken ASAP.

National Association of Regulatory Utility Commissioners
New York State Public Service Commission

The proposed standard lacks a definitive statement indicating that it is unacceptable to operate the bulk system beyond established limits and that the system must be returned to a reliable state of operation within a reasonable time frame.

The standard has been revised to add the phrase, 'without delay' to indicate that actions should be taken ASAP. The standard has also been revised to indicate that T_v may not be greater than 30 minutes.

New York State Reliability Council

LIPA LIPA (Transmission Owners)

In addition, proposed Standard 200 fails to clearly require the Reliability Authority to initiate corrective actions as soon as a limit is exceeded.

We believe it is an unwarranted risk for Standard 200 to degrade present NERC criteria, particularly in the aftermath of the August 14, 2003 Blackout.

The focus of this standard is on preventing an incident of exceeding an IROL, not just to take action after an IROL has been exceeded, which is the focus of Policy 2. The standard has been revised to add the phrase, 'without delay' to indicate that actions should be taken ASAP.

National Grid USA

New Brunswick Power Corporation NBPC

Niagara Mohawk NMPC

New York Power Authority MED

Northeast Utilities NU

Nova Scotia Power NSPI

Ontario - Independent Electricity Market Operator IMO

United Illuminating UICO

Standard 200 should clearly reflect requirements and measures that require all Reliability Authorities to initiate *immediate* corrective actions *as soon as* an Interconnection Reliability Operating Limit (IROL) is exceeded or the system is in an unanalyzed state. It is NPCC's position that NERC Standards should ensure mitigating actions are implemented when instability, uncontrolled separation, or cascading outages would occur as a result of a change in one or more operating parameter(s) *as soon as the condition exists.*

The focus of this standard is on preventing an incident of exceeding an IROL, not just to take action after an IROL has been exceeded, which is the focus of Policy 2. The standard has been revised to add the phrase, 'without delay' to indicate that actions should be taken ASAP.

Wisconsin Public Service Corporation WPS

Language is not specific enough to operators about when to begin taking immediate action to rectify the limit violation.
The standard has been revised to add the phrase, 'without delay' to indicate that actions should be taken ASAP.

New York Power Authority NYPA

Standard 200 should clearly reflect requirements and measures that require all Reliability Authorities to initiate corrective actions as soon as an Interconnection Reliability Operating Limit (IROL) is exceeded. It is NPCC's position that it should be ensured mitigating actions are implemented when instability, uncontrolled separation, or cascading outages would occur as a result of a change in one or more operating parameter(s) as soon as the condition exists.

The focus of this standard is on preventing an incident of exceeding an IROL, not just to take action after an IROL has been exceeded, which is the focus of Policy 2. The standard has been revised to add the phrase, 'without delay' to indicate that actions should be taken ASAP.

Midwest Independent Transmission System Operator, Inc.

Several people have mentioned that the Standard doesn't require immediate action. While the standard should encourage expeditious response, as the industry found out with the DCS, operators need a few minutes to interpret readings and alarms, select the proper response and then get resources deployed.

The standard has been revised to add the phrase, 'without delay' to indicate that actions should be taken ASAP.

Entergy Services ENTE (LSEs)

Section 204(a) needs to be worded so that it is abundantly clear that a Reliability Authority must always act prudently to maintain the reliability of the system given the actual situation that has developed. In certain situations, prudent action may not include taking action to prevent exceeding a predetermined IROL or even mitigating the magnitude or duration of a violation. The definition of IROL is that it is a limit that, if exceeded, "could" lead to instability....... IROLs are no more than measure points to be used in monitoring the system. Any actions taken or directed by a reliability authority must be prudent based on the actual situation and system conditions and with the goal of maintaining reliability not only for the immediate time period but for the entire operational planning time period as well.

The standard has been revised to add the phrase, 'without delay' to indicate that actions should be taken ASAP.

- ***Add a requirement to Implement Conservative Operations for Unknown or Unstudied Conditions***
  Wisconsin Energy Corporation - PM WEC

Exceeding an IROL is a indicator of a potentially catastrophic event, in addition to the above, the RA should also be required to act by implementing "conservative operations" for conditions that are unknown or not studied and that do not have a defined IROL.

Requiring that system operators take actions when their system is in an unanalyzed state is beyond the scope of this standard.

- ***Add a requirement to document RA's Authority***

Public Service Electric and Gas Company (LSEs)

There must be an express provision stating that Reliability Authorities have authority over all entities with facilities or operating within the RA's footprint. (Section 204)

There is a requirement in the RA Certification Standard that addresses this. That standard requires the RA to have a written agreement with all of the entities that report to the RA as well as with adjacent RAs that defines the authority of the RA.

Electricity Consumers Resource Council

We are concerned that the definition or criteria regarding the differentiation between "Local" and "Wide Area Impact" is unclear. The proposed standard does not appear to provide adequate responses if the electric area to be included in the limit is larger than the portion of the transmission system under the authority of a single Reliability Authority (RA). The standard should clearly explain how an RA can order all TO's, BA's, IA's and other RA's to take necessary actions if they are not within the controlling RA's reliability area.

The SDT did not use the terms, 'wide area impact' or 'local area' in this standard. There is no industry consensus on the definition of these terms. The SDT will request that these terms continue to be refined, but recommends that this refinement take place outside the scope of this standard.

The Coordinate Operations standard addresses the coordination of actions between two RAs. There is a requirement in this standard that requires the entities that work under the direction of an RA to follow that RA's directives. RA Certification is expected to include requirements that the RA have written agreements with all entities that operate within its physical and/or electrical boundaries. These agreements are expected to address the authority of the RA to direct entities to take actions under normal and abnormal conditions.

Wisconsin Energy Corporation - PM WEC

The RA will have several conditions in which it is required to give operating directives to other functional entities, to require those entities to have specific requirements for documenting RA directives related to IROL is confusing. Suggest all directives issued by the RA shall be documented per these measures.

The standard has been revised to add a requirement that the RA include specific language in its directives to let the recipient know that the directive is related to an IROL.

Reliant Resources Inc RRI

Sec 204 **-** There is no definitive authority given to the Reliability Authorities over each and every entity within their footprint. Lack of authority will jeopardize the effectiveness of the requirements within Standard 200 and ultimately the reliability of the Interconnection(s).

RA Certification is expected to include requirements that the RA have written agreements with all entities that operate within its physical and/or electrical boundaries. These agreements are expected to address the authority of the RA to direct entities to take actions under normal and abnormal conditions.

WECC

Minnesota Power MP

Public Works Commission Fayetteville PWCF

Southern California Edison SCET

Salt River Project SRP

Tucson Electric Power Company TEPC

Platte River Power Authority TP PRPA

California Energy Commission

The standard focuses too much attention on reporting and documentation rather than focusing on the need for operators to take timely and appropriate actions to correct operating limit violations. Specific language has been added to clarify that actions be taken, "without delay." While there are minor sanctions for poor documentation, the standard applies larger sanctions for instances of exceeding an IROL for time greater than T_v , for ignoring RA directives, and for not monitoring.

Gainsville Regional Utilities GVL (LSEs)

City of Tallahassee TAL (Transmission Owners)

Who is responsible for implementing an IROL mitigation plan? Transmission Owners? RA? Does the RA develop the plan or does the Transmission Owner?
IROL mitigation plans are under the control of the RA. The RA may direct other entities to take actions as part of one of these plans.

- ***Limit documentation to instances of exceeding Tv***

FirstEnergy Corp

FirstEnergy does not support documenting all limit violations. We need to be able to documents only those violations that are in excess of Tv. Documenting all limit violations would be an effort with no real reward or substantive information.

There should be very few IROL violations of any duration. The documentation required is that which is typically recorded by system operators in the normal course of duties. There are three reasons for requiring that each instance of exceeding an IROL be documented:

- To ensure that System Operators maintain 'situational awareness' of the seriousness of ever exceeding an IROL.
- To ensure that there is sufficient documentation to support an audit of whether actions are being taken to mitigate instances of exceeding an IROL.
- To ensure that the information on exceeding IROLs is available when needed by NERC and/or Regions for reliability analyses.

FirstEnergy Solutions FESC (LSEs)

We do not support documenting all limit violations. Only those violations that are in excess of Tv are needed.

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- To ensure that the information on exceeding IROLs is available when needed by NERC and/or Regions for reliability analyses.

FirstEnergy Solutions FESC (Brokers, Aggregators, and Marketers)

A standard should be a strandard for all RAs. Documenting every limit violation may prove to be burdensome with little imact on reliability.

There should be very few IROL violations of any duration. The documentation required is that which is typically recorded by system operators in the normal course of duties. There are three reasons for requiring that each instance of exceeding an IROL be documented:

- To ensure that System Operators maintain 'situational awareness' of the seriousness of ever exceeding an IROL.

- To ensure that there is sufficient documentation to support an audit of whether actions are being taken to mitigate instances of exceeding an IROL.
- To ensure that the information on exceeding IROLs is available when needed by NERC and/or Regions for reliability analyses.

MAIN

Contrasting operator actions versus documentation, the standard is relatively overly focused on documentation. As a specific example of this, Section 204, which addresses "Actions," permits an IROL shorter than Tv yet still requires documentation of the event (Section 204 (e) (1)). The documentation required by this standard is so burdensome that it risks system operations could become distracted from its primary role of acting on IROL's.

There should be very few IROL violations of any duration. The documentation required is that which is typically recorded by system operators in the normal course of duties. There are three reasons for requiring that each instance of exceeding an IROL be documented:

- To ensure that System Operators maintain 'situational awareness' of the seriousness of ever exceeding an IROL.
- To ensure that there is sufficient documentation to support an audit of whether actions are being taken to mitigate instances of exceeding an IROL.
- To ensure that the information on exceeding IROLs is available when needed by NERC and/or Regions for reliability analyses.

NPCC
New York Power Authority MED
Northeast Utilities NU
LIPA LIPA (Transmission Owners)

Documentation should be required only for those limit violations in excess of the time-duration T_v value.

There should be very few IROL violations of any duration. The documentation required is that which is typically recorded by system operators in the normal course of duties. There are three reasons for requiring that each instance of exceeding an IROL be documented:

- To ensure that System Operators maintain 'situational awareness' of the seriousness of ever exceeding an IROL.
- To ensure that there is sufficient documentation to support an audit of whether actions are being taken to mitigate instances of exceeding an IROL.
- To ensure that the information on exceeding IROLs is available when needed by NERC and/or Regions for reliability analyses.

ISO New England Inc ISNE

ISO-NE does not support documenting all limit violations, but only those in excess of the time-duration TV value. This requirement would be a large effort while providing little or no information, as limits are exceeded for very small amounts of time and magnitude just by virtue of normal power system operations.

There should be very few IROL violations of any duration. The documentation required is that which is typically recorded by system operators in the normal course of duties. There are three reasons for requiring that each instance of exceeding an IROL be documented:

- To ensure that System Operators maintain 'situational awareness' of the seriousness of ever exceeding an IROL.
- To ensure that there is sufficient documentation to support an audit of whether actions are being taken to mitigate instances of exceeding an IROL.
- To ensure that the information on exceeding IROLs is available when needed by NERC and/or Regions for reliability analyses.

National Grid USA

New Brunswick Power Corporation NBPC

New York Power Authority MED

Northeast Utilities NU

Nova Scotia Power NSPI

Ontario - Independent Electricity Market Operator IMO

National Grid (NPCC) further does not support documenting all limit violations, but only those in excess of the time-duration Tv value. This requirement would be a huge effort while providing little or no information, as limits are exceeded for very small amounts of time on a regular basis just by virtue of power system operations.

There should be very few IROL violations of any duration. The documentation required is that which is typically recorded by system operators in the normal course of duties.

Hydro One Networks Inc (LSEs)

We further only support recording limit violations, but documenting and reporting only those in excess of the time-duration TV value. Reporting all limit violations would be a huge effort while providing little or no compliance information, as limits are exceeded for very small amounts of time on a regular basis just by virtue of power system operations.

There should be very few IROL violations of any duration. The documentation required is that which is typically recorded by system operators in the normal course of duties.

There are three reasons for requiring that each instance of exceeding an IROL be documented:

- To ensure that System Operators maintain 'situational awareness' of the seriousness of ever exceeding an IROL.
- To ensure that there is sufficient documentation to support an audit of whether actions are being taken to mitigate instances of exceeding an IROL.
- To ensure that the information on exceeding IROLs is available when needed by NERC and/or Regions for reliability analyses.

- ***Report 'near misses' to Region***

Southern Company Services SOCO (Generators)
Southern Company Services SOCO (Transmission Owners)
Georgia Power Company (LSEs)

Although the standard states that all instances of exceeding IROLs must be documented (reference excerpt from the definitions below), they are not required to be sent to NERC or the Regions. These "near miss" situations (where the IROL is mitigated in under Tv) contain valuable information and should be reported as well. By tracking these near misses, the compliance monitor can determine how close to the edge the system is being operated. Analysis of this data could indicate that Tv is being used as a grace period, which is in direct conflict with the OLDTF's recommendations and good utility practice . However, there does not appear to be a compliance "hammer" to prevent entities from using Tv as a grace period. This should somehow be incorporated into the levels of non-compliance and penalties.
Southern recommends that near misses be reported to the Region.

There are three reasons for requiring that each instance of exceeding an IROL be documented. Any Region that wants to collect this data is free to do so, and may either handle this with a Regional Difference to this standard, or through a separate Regional requirement.

- To ensure that System Operators maintain 'situational awareness' of the seriousness of ever exceeding an IROL.
- To ensure that there is sufficient documentation to support an audit of whether actions are being taken to mitigate instances of exceeding an IROL.
- To ensure that the information on exceeding IROLs is available when needed by NERC and/or Regions for reliability analyses.

- ***Question on No Overt Action***

City of Tallahassee TAL

footnote- How can we allow 'no overt action' for an expected IROL violation. By 207.a.1 the RA "shall have an action plan to prevent..." If he has to have a plan, how can we allow "no overt action"?
Although this standard requires the RA to have a plan, this standard does not require that the plan be followed because real-time conditions often do not duplicate the conditions that were anticipated when a plan was developed. If a limit is being approached, but the RA knows that it will be relieved before it is exceeded (for example if a unit is coming on line in the next 5 minutes) then the RA may take "no overt action". Note that if the RA elects to take "no overt action" the RA is required to document this decision so that the decision can be reviewed.

- ***Include Time to Respond to Directives***

Avista Corp. AVA
Avista Corp. Washington Water Power Division AVWP

The standard does not address a time frame in which a response to a directive is required. In order for the standard to be affective there must be a time frame developed to monitor proper response.

The RA may include a time constraint in its directive, but this is not required. There are many instances where an RA may issue a directive with a time constraint such as, 'as soon as possible' – and this is not measurable. The RA is responsible for achieving the desired results.

Sanctions

Summary Consideration: The sanction for exceeding an IROL for time greater than Tv was modified so that it is proportional to the magnitude and duration of the event and is not tied to the size of any entity.

(f) Sanctions

Level four noncompliance sanctions shall be the greater of the fixed dollar sanctions listed in the matrix, or the ~~number of megawatts above the Interconnection Reliability Operating Limit multiplied by the dollar value for the number of times of noncompliance.~~ dollar amount that corresponds to the magnitude and duration of the event as highlighted in the following table:

If the Maximum Value % over the Limit (measured after the event duration exceeds T_v) is: Max Value % = (Max Value/ IROL limit –1)*100	**And the event duration exceeds its T_v by __ minutes:**	**Then Multiply the Level 4 $ sanction by:**
0% < Max Value % ≤ 5%	T_v < Duration ≤ T_v + 5 minutes	5
	T_v + 5 minutes < Duration ≤ T_v + 10 minutes	10
	T_v + 10 minutes < Duration ≤ T_v + 15 minutes	15
	Duration > T_v + 15 minutes	20
5% < Max Value % ≤ 10%	T_v < Duration ≤ T_v + 5 minutes	10
	T_v + 5 minutes < Duration ≤ T_v + 10 minutes	15
	T_v + 10 minutes < Duration ≤ T_v + 15 minutes	20
	Duration > T_v + 15 minutes	25
10% < Max Value % ≤ 15%	T_v < Duration ≤ T_v + 5 minutes	15
	T_v + 5 minutes < Duration ≤ T_v + 10 minutes	20
	T_v + 10 minutes < Duration ≤ T_v + 15 minutes	25
	Duration > T_v + 15 minutes	30
15% < Max Value % ≤ 20%	T_v < Duration ≤ T_v + 5 minutes	20
	T_v + 5 minutes < Duration ≤ T_v + 10 minutes	25
	T_v + 10 minutes < Duration ≤ T_v + 15 minutes	30
	Duration > T_v + 15 minutes	35
20% < Max Value % ≤ 25%	T_v < Duration ≤ T_v + 5 minutes	25
	T_v + 5 minutes < Duration ≤ T_v + 10 minutes	30
	T_v + 10 minutes < Duration ≤ T_v + 15 minutes	35
	Duration > T_v + 15 minutes	40
25% < Max Value % ≤ 30%	T_v < Duration ≤ T_v + 5 minutes	30
	T_v + 5 minutes < Duration ≤ T_v + 10 minutes	35
	T_v + 10 minutes < Duration ≤ T_v + 15 minutes	40
	Duration > T_v + 15 minutes	45

Southeastern Electric Reliability Council

Once Tv is violated there needs to be an incentive to get it back within limits soon. As currently written, the standard does not distinguish between short and long Tv violations.

The emphasis of this standard is different from that of Policy 2. Policy 2 focuses solely on actions after a limit has been exceeded. This standard puts much more emphasis on preventing instances of exceeding IROLs.

The sanctions for this requirement have been revised so that fines for exceeding IROLs for time greater than T_v are proportional to the magnitude and duration of the incident.

Georgia Power Company (LSEs)

Southern believes that the time an IROL is exceeded should be considered in levels of non-compliance or penalties. Once T_v is violated, there needs to be an incentive to get it back within limits sooner rather than later. As currently written, the standard does not distinguish between violations that last for T_v + 5 minutes vs. T_v + 5 hours.

Because T_v isn't standard for all IROLs, using the duration of time that a limit is exceeded can't be applied in a 'fair' manner. Changes were made to the standard to set a max for Tv of 30 minutes. We don't want to encourage RAs to set T_v at 30 minutes for all limits just to avoid penalties. There were several balloters who suggested that the magnitude of the sanction be proportional to the magnitude and duration of exceeding the limit, and the SDT made this modification. .

Carolina Power & Light Company CPL (Transmission Owners)
Carolina Power & Light Company CPL (LSEs)
Carolina Power & Light Company CPL (Generators)

The time an IROL is exceeded should be considered in levels of non-compliance or penalties. Once T_v is violated, there needs to be an incentive to get it back within limits sooner rather than later. As currently written, the standard does not distinguish between violations that last for T_v + 5 minutes vs. T_v + 5 hours.

Because T_v isn't standard for all IROLs, using the duration of time that a limit is exceeded can't be applied in a 'fair' manner. Changes were made to the standard to set a max for Tv of 30 minutes. We don't want to encourage RAs to set T_v at 30 minutes for all limits just to avoid penalties. There were several balloters who suggested that the magnitude of the sanction be proportional to the magnitude and duration of exceeding the limit, and the SDT made this modification.

Kansas City Power & Light KCPL

Is 30 seconds too short of a time for a reset durartion for Tv?

The thirty seconds was selected because it represented the longest period of time that could be associated with a 'bad scan'. The SDT contacted the balloter to determine what value the balloter suggests would be sufficient, and the balloter suggested one minute. This is what will be proposed to the industry. We will ask the industry for feedback on whether 30 seconds is too short a period of time and will offer 'one minute' as a suggested alternative.

MAIN

Once the violation comes back within limits the standard states the event is over within 30 seconds. This is too soon,- it should be a longer period, perhaps 10 minutes.

The thirty seconds was selected because it represented the longest period of time that could be associated with a ‘bad scan’. We will ask the industry for feedback on whether 30 seconds is too short a period of time and will offer 10 minutes as a suggested alternative.

Avista Corp. AVA

Avista Corp. Washington Water Power Division AVWP

The sanctions need to be set up based on % overload not MW overload. Under the proposed standard a 10 MW overload on a 10,000 MW path will have the same sanction as a 10 MW overload on a 100 MW path.

The sanctions for this requirement have been revised so that fines for exceeding IROLs for time greater than T_v are proportional to the magnitude and duration of the incident.

Wisconsin Public Service Corporation WPS

Penalty matrix should be based upon the % of line capacity violation versus megawatt exceedence.

The sanctions for this requirement have been revised so that fines for exceeding IROLs for time greater than T_v are proportional to the magnitude and duration of the incident.

Bonneville Power Administration Transmission BPAT

In Section 204.f (Actions/Sanctions) there should be a clear definition of the megawatt value used to calculate the sanctions. Is the megawatt value the maximum value the IROL is exceeded, the megawatt value the IROL is exceeded at time Tv, or an average value of the IROL violation over the Tv period? We recommend that the MW violation be based on an average MW percentage of the violation of the IROL over the time period that exceeds Tv.

We would also like to see a time component added in calculating the sanctions. The time component would add motivation to alleviate a violation instead of letting a small violation continue for a long period of time. An example of a time component would the severity of the violation would double if the time of the reportable IROL violation exceeded Tv such that the IROL has been exceeded for 2Tv .

The sanctions for this requirement have been revised so that fines for exceeding IROLs for time greater than T_v are proportional to the magnitude and duration of the incident.

The maximum value used for the sanction is the maximum value during the time period after T_v was exceeded.

AEP Service Corp -- Transmission System AEP

Sanctions are defined on a per MW basis for violations of operating limits but a more realistic approach would be to base them on percentage violations. Ten MWs on a 115 kV facility is probably more critical than 10 MW on a 500 kV facility although the 500 kV facility may be more critical for interconnection reliability.

The sanctions for this requirement have been revised so that fines for exceeding IROLs for time greater than T_v are proportional to the magnitude and duration of the incident.

City Water Light & Power CWLP

Also, in the penalty matrix, the violations should not be based on actual MW, but be based on the percent of the facility rating. For example, being 20 MW over the rating of a 100 MW rated facility is a lot worse than being 20 MW over a 1000 MW rated facility.

The sanctions for this requirement have been revised so that fines for exceeding IROLs for time greater than T_v are proportional to the magnitude and duration of the incident. The dollar amount used as the multiplier is a fixed dollar amount and is not related to the size of any entity or any entity's facility.

City of Tallahassee TAL

If a Tv is set to zero due to the high risk, and that IROL is exceeded due to "acts of god" or circumstances beyond the entities control, the offending party is subject to sanctions, or having this event count against them, if their Special Protection Scheme fails.

This is correct. However, this standard's primary focus is on <u>preventing</u> any incident of exceeding an IORL. IROLs should not be exceeded.

Gainesville Regional Utilities GVL (Generators)

I also believe that the sanction matrix should be clarified. Is it $ per mw over IROL Limit, or $ per Mw for facility. I agree with a % over IROL that exceeds 30 minutes may have sanctions levied. But I must reitterate clarify the Sanction matrix.

The sanctions for this requirement have been revised so that fines for exceeding IROLs for time greater than T_v are proportional to the magnitude and duration of the incident. The dollar amount used as the multiplier is a fixed dollar amount and is not related to the size of any entity or any entity's facility.

Kansas City Power & Light KCPL

The per MW basis for violations is inappropriate, a percentage basis is mor realistic.

The sanctions for this requirement have been revised so that fines for exceeding IROLs for time greater than T_v are proportional to the magnitude and duration of the incident. The dollar amount used as the multiplier is a fixed dollar amount and is not related to the size of any entity or any entity's facility.

Manitoba Hydro Electric Board MHEB (Electricity Brokers, Aggregators, and Marketers)

Manitoba Hydro MHEB (LSEs)

Manitoba Hydro (Transmission Owners)

Depending on the final definition of an IROL (in accordance with standard 600, or to avoid cascading, instability and uncontrolled separation), it may be essential to consider the extent of the violation (i.e., was the limit exceeded by 1% or 200 %?). If the IROL definition remains unchanged then it is very likely that even minimal violations are serious and, as well, that Tv may have to be very small.

The sanctions for this requirement have been revised so that fines for exceeding IROLs for time greater than T_v are proportional to the magnitude and duration of the incident. The dollar amount used as the multiplier is a fixed dollar amount and is not related to the size of any entity or any entity's facility.

Allegheny Power AP

Financial sanctions may be less effective than desired when the structure of the Reliability Authority (RTO) allows for the penalty to be passed on to others.

Addressing this concern is outside the scope of the SDT.

Southern Company Services SOCO (Generators)
Southern Company Services SOCO (Transmission Owners)

Southern believes that the time an IROL is exceeded should be considered in levels of non-compliance or penalties. Once Tv is violated, there needs to be an incentive to get it back within limits sooner rather than later. As currently written, the standard does not distinguish between violations that last for Tv + 5 minutes vs. Tv + 5 hours.

The sanctions for this requirement have been revised so that fines for exceeding IROLs for time greater than T_v are proportional to the magnitude and duration of the incident.

MAIN

The penalty matrix should be based upon the % of line capacity violation versus the megawatt excess.

The sanctions for this requirement have been revised so that fines for exceeding IROLs for time greater than T_v are proportional to the magnitude and duration of the incident. The dollar amount used as the multiplier is a fixed dollar amount and is not related to the size of any entity or any entity's facility.

- ***Other Comments***

WECC
Minnesota Power MP
Public Works Commission Fayetteville PWCF
Southern California Edison SCET
Salt River Project SRP
Tucson Electric Power Company TEPC
Platte River Power Authority TP PRPA
California Energy Commission

The proposed standard will be difficult and impractical to enforce. The standard adds an enforcement burden of proof in that one would have to demonstrate that the violation of the limit "could lead to instability, uncontrolled separation, or cascading outages" for the actual operating conditions which existed. As such there may have to be a technical study conducted almost every time a limit is exceeded to assess each reported potential OWL violation to demonstrate the violation would or would not have resulted in cascading for that particular operating point. We do not believe it is practical to expect that a study be run representing the system conditions in effect at the time for each operating limit violation to assess whether the consequences would make the violation reportable.

None of the compliance monitoring processes in this standard include asking that the RA conduct a post-mortem technical study. IROLs are established prior to an event occurring and shall be enforceable in real-time. System Operators must operate so that they don't exceed identified IROLs – its not helpful to identify IROLs after-the-fact.

The SOLs that are identified as IROLs must be developed following Standard 600. Under Standard 600, studies are conducted to identify the SOLs as well as the consequences of violating one of these limits. Studies are not required to be conducted after an IROL has been identified and this standard does not require that any entity demonstrate 'after the fact' that a limit was/was not an IROL.

Whether or not existing system conditions match the conditions studied for the original identification of the IROL, the IROL is still an IROL as far as the system operators are concerned. The IROL remains an IROL until the system operators are informed differently.

205 Data Specification and Collection

Requirements

(a) Requirements

(1) The Reliability Authority shall specify and collect the data it needs to support Real-time Monitoring, Operational Planning Analyses, and Real-time Assessments conducted relative to operating within its Reliability Authority Area's Interconnection Reliability Operating Limits. The Reliability Authority shall collect this data from the entities performing functions that have real-time Facilities monitored by the Reliability Authority, and from entities that provide Facility status to the Reliability Authority. This includes specifying and collecting data from the following:

(i) Balancing Authorities

(ii) Generator Owners

(iii) Generator Operators

(iv) Load-serving Entities

(v) Reliability Authorities

(vi) Transmission Operators

(vii) Transmission Owners

Summary Consideration:

The requirement was modified to add the adjective, 'real-time' to the term Facilities. This change was requested by a balloter to improve the consistency between Requirements 205 and 206.

Tenaska Inc

Data requirements in Section 205 need to be more specific to prevent burdensome, discriminatory requests for data. Also, the data request should only be for reliability information and not for competitive cost information. Section 208 should be applicable to anyone who has the ability to impact reliability on the bulk system (transmission owners, transmission operators, generators, load serving entities, etc.). It appears that Section 201 gives tremendous latitude for the reliability authorities to pick and choose what facilities are included which could lead to discriminatory practices. Some more specific language should be added to identify what facilities are in or out.

The requirement is limited to data needed to support reliability. Requiring that all RAs have a common data specification would not be in the best interests of reliability, since some RAs may have a justified need for more data than other RAs.

Regarding Section 208: The entities listed as needing to provide data are those entities that are defined in the Functional Model as needing to provide data to the RA for monitoring and analyses. Other entities may provide data to the RA for other purposes, but that is outside the scope of this standard.

Regarding Section 201: The RA needs the latitude to identify which Facilities it needs to monitor.

Bonneville Power Administration Transmission BPAT

Sections 205 and 206 both deal with "data". Only in Section 205.b.3 is "status" mentioned. To perform a real time analysis requires both "data" and "status". We recommend removing "status" from Section 205.b.3 with the understanding that "data" includes "status".

The standard has been revised to include the phrase "and real-time Facility status" in both Requirements 205 and 206.

AEP Service Corp -- Transmission System AEP
Oklahoma Gas and Electric OKGE

Requirements (a)(i), (a)(ii) and (a)(iii) are too open-ended on the part of the reliability authority. Justification should be required for all requested data to prevent unreasonable and burdensome requests on the part of the reliability authority. The data requested and the timing of the delivery of the data should be mutually agreeable to the reliability authority and the responding entity.

The standard should include a minimum, default set of data, such as that spelled out in Appendix 4B, and provide that as a guide for types of data that may be requested.
The requirement is limited to data needed to support reliability. Requiring that all RAs have a common data specification would not be in the best interests of reliability, since some RAs may have a justified need for more data than other RAs.

Requirement (a)(iii) appears to be repeated again as a measure in Measure (b)(iii). Shouldn't Requirement (a)(iii) be moved to Standard 206 since it deals with provision of the data?

In fact, there is a great deal of material in 205 that is related data provision. Shouldn't all of this be moved to 206? Perhaps additional clarification between 205 and 206 is all that is needed.

These requirements are closely linked – Requirement 205 requires that the RA develop a data specification to let entities know what data it needs – Requirement 206 requires that those entities provide the data as requested.

206(e) Only one data point out of potentially thousands of points could cause non-compliance as specified in (e). This implies that nothing less than 100% of the data, 100% of the time is sufficient. Is this the intent of the standard? Is a transducer failure in a remote substation as damaging to reliability of the interconnection as the loss of an entire ICCP link between a responding entity and its reliability authority? Is a failure for one scan cycle as critical as that point not being available for days or weeks? It would appear that non-compliance associated with this standard needs revisiting.
When this standard is re-posted for comment, please provide a sample that the industry can review. The standard has been written so that the RA isn't required to 'turn in' the names of entities that are non-compliant for a single piece of data. The standard was written so that the RA has an opportunity to resolve any lack of data with the entity responsible and only report instances where there are blatant violations.

Kansas City Power & Light KCPL

Requirements are to open ended. Establish a minimum and let RA justify additional.

The requirement is limited to data needed to support reliability. Requiring that all RAs have a common data specification would not be in the best interests of reliability, since some RAs may have a justified need for more data than other RAs.

Levels of Non-compliance

AEP Service Corp -- Transmission System AEP
Oklahoma Gas and Electric OKGE

There appears to be inconsistency between non-compliance in 205 and 206. If a reliability authority makes an unreasonable data request in 205 and doesn't get the requested data within the specified timeframe, then the reliability authority is only penalized at a level one. But if a responding entity loses one data point for one four-second data scan, that responding entity is blasted with a level four penalty. There does not appear to be equity here.

The SDT suggested different sanctions for not having a data spec and for not providing data as requested. Here is the SDT's reasoning for the different levels of non-compliance:

> The data specification does need to be complete. Most entities already exchange data, and some entities may not have a 'complete' data specification. A lower level sanction recognizes that some data that is supplied may not be documented on a specification, and there may need to be some 'warnings' to motivate the RA to improve its documentation.
>
> The RA is strongly motivated to perform well and is required to meet stringent certification requirements so the RA will most certainly request the data it needs.
>
> If data is needed and specified in a written document, then it does need to be provided. Not providing data that has been formally requested is serious because it can jeopardize the RA's ability to accurately monitor and assess its Reliability Area. In most cases, the Compliance Monitor only finds out about this violation if the RA tries to resolve the discrepancy, but the RA is unable to obtain the data it needs.

206 Data Provision

Levels of Non-compliance

Kansas City Power & Light KCPL

Is missing one data point as severe as an entire ICCP link being down?

As envisioned, the RA would use common sense upon the loss of a single data point for a single scan or even multiple scans, and wouldn't report that to its Compliance Monitor, therefore there would be no associated sanction.

AEP Service Corp -- Transmission System AEP

Oklahoma Gas and Electric OKGE

There appears to be inconsistency between non-compliance in 205 and 206. If a reliability authority makes an unreasonable data request in 205 and doesn't get the requested data within the specified timeframe, then the reliability authority is only penalized at a level one. But if a responding entity loses one data point for one four-second data scan, that responding entity is blasted with a level four penalty. There does not appear to be equity here.

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> If data is needed and specified in a written document, then it does need to be provided. Not providing data that has been formally requested is serious because it can jeopardize the RA's ability to accurately monitor and assess its Reliability Area. In most cases, the Compliance Monitor only finds out about this violation if the RA tries to resolve the discrepancy, but the RA is unable to obtain the data it needs.

Ontario Power Generation Inc OPG

SECTION 206:
This section identifies levels of non-compliance and in this case, the only applicable level is level 4, which appears to be unnecesarily harsh.

If data is needed and specified in a written document, then it does need to be provided. Not providing data that has been formally requested is serious because it can jeopardize the RA's ability to accurately monitor and assess its Reliability Area. In most cases, the Compliance Monitor only finds out about this violation if the RA tries to resolve the discrepancy, but the RA is unable to obtain the data it needs.

Ontario Power Generation Inc OPG

SECTION 206:
Entities obliged to provide data to RAs under this section of the Standard should have a means of appealing the decision of the RA on the grounds of relevance.

There is a dispute resolution process that could be used to resolve any difference.

Sanctions

City of Tallahassee TAL

Under the Sanctions - Fixed Dollars: In reference to the last line; "If those assumptions prove wrong in the future, yet they are made in good faith using good practices, entities should not be harshly penalized for the outcome." Why is there ANY penalty if a best guess was a little off?

The sentence you've referenced is from the Sanctions Table that is part of the Compliance Enforcement Program approved by the NERC Board. The referenced sentence has been taken out of context – it was written in reference to planning standards, not operations-related standards. The set of paragraphs that explain the rational for using flat fines and dollars per MW sanctions are as follows:

> Fixed Dollars
>
> This sanction is used when a letter is not enough and a stronger message is desired. Fixed dollars are typically assigned as a one-time fine that is ideal for measures involving planning-related standards. Many planning actions use forward-looking assumptions. If those assumptions prove wrong in the future, yet they are made in good faith using good practices, entities should not be harshly penalized for the outcome."
>
> Dollars per MW
>
> Dollars per MW sanctions are oriented toward operationally based standards. The MW can be load, generation, or flow on a line. Reasonableness of a sanction needs to be figured into assessing $/MW penalties. Assessing large financial penalties is not the goal, but sending a message with proper emphasis on $$$ can be controlled with the multiplier.

Because the requirement to follow the RA's directives isn't always tied to a certain number of MW, the SDT drafted this standard with "Fixed Dollar" sanctions rather than "Dollars per MW" sanctions.

207 Action Plan

Requirements

207 ~~Action Plan~~ Processes, Procedures or Plans for Preventing and Mitigating IROLs

(a) Requirements

(1) The Reliability Authority shall have ~~an action plan~~ a process, procedure or plan that identifies actions it shall take or actions it shall direct others to take, to prevent ~~or~~ and mitigate instances of exceeding its Interconnection Reliability Operating Limits.

Summary Consideration:

This requirement was modified to change the word, ‘plan’ to the phrase, ‘process, procedure or plan’. This change aligns the language used in this standard with the language used in the Certification SARs and the Coordinate Operations standard. The word, ‘or’ was changed to ‘and’ to clarify that the documents must address Both prevention And mitigation of instances of exceeding IROLs.

- ***Add Requirement for an action plan for conservative operations***

Wisconsin Energy Corporation - PM WEC

Exceeding an IROL is a indicator of a potentially catastrophic event, in addition to the above, the RA should also be required to have an action plan for implementing “conservative operations” for conditions that are unknown or not studied and that do not have a defined IROL.

Requiring that system operators take actions when their system is in an unanalyzed state is beyond the scope of this standard.

- ***Require alternatives to curtailments of mkt transactions – comments to reference NAESB practices***

Reliant Resources Inc RRI

NERC should include in Standard 200, the obligation for operators (RAs) to include as part of its “Action Plan” to mitigate violations to the Interconnected Reliability Operating Limits, procedures that allow transmission customers alternatives to curtailment of market transactions. Such alternative procedures should be referenced in the Action Plans and specific procedures can be provided through another forum, NAESB, that could develop interconnection wide or regional based procedures to enable redispatch or other alternatives to traditional “TLR-type” transaction curtailment.

The Standard does not require nor does it preclude the use of any specific solutions in preventing or mitigating instances of exceeding IROLs.

Reliant Resources Inc RRI

The problem with NERC Std 200 is that it only requires a "Action Plan" to be in place to mitigate system overloads. Instead, what Standard 200 should do is recognize that RAs have many means to reduce system overloads that can keep as many transactions in place as possible.

The Standard requires processes, procedures or plans to Prevent instances of exceeding IROLs **as well as** action plans for Mitigating instances of exceeding IROLs. These processes, procedures or plans don't require nor do they preclude the use of any specific solution.

Reliant Resources Inc RRI

The way Std 200 is now written; an RA may have as a procedure - e.g. - a load shedding scheme, or bi-lateral transaction curtailment scheme (NERC TLR) to fulfill the NERC Standard 200 requirement for an Action Plan. Neither one of these solutions should be allowed as a first action procedure. By incorporating market procedures through reference in the Action Plan, RAs will be incentivized to utilize other procedures that strive to retain market transactions through the use of financial mechanisms rather than cut them as a first action means to get out of system operating limit violations.

The Standard requires processes, procedures or plans to Prevent instances of exceeding IROLs **as well as** action plans for Mitigating instances of exceeding IROLs. These processes, procedures or plans don't require nor do they preclude the use of any specific solution.

Adding constraints to the RA's options may limit their ability to protect reliability.

Ontario Power Generation Inc OPG

This section identifies the need for RAs to have an action plan for dealing with the exceedances of IROLs. However, such a plan can have substantial commercial implications and the Standard provides no guideline for defining the plan or the mechanism by which a proposed plan can be challenged or modified to mitigate the commercial impacts. OPG believes the most appropriate approach would be to develop plan(s) through NAESB, for adoption by RAs, prior to implementation of this NERC standard.

These processes, procedures or plans are for support of interconnection reliability, they aren't designed to be used to mitigate commercial impacts. NERC is responsible for development of reliability-related standards.

Reliant Resources Inc RRI

Sec 207 appears to be the replacement for the current TLR process detailed in NERC Operating Policy Appendix 9C1. References to NAESB or other market based procedures to "unwind" market transactions should be required. NAESB is currently struggling to scope out the needs for a commercial standard to complement the NERC Standard 200. Communication within the appropriate working levels in both the NERC and NAESB forums is required for efficient standards development.

The Standard requires processes, procedures or plans to Prevent instances of exceeding IROLs **as well as** action plans for Mitigating instances of exceeding IROLs. These processes, procedures or plans don't require nor do they preclude the use of any specific solution.

Adding constraints to the RA's options may limit their ability to protect reliability.

- ***Require consistent Action Plans between RAs***

Reliant Resources Inc RRI

Sec 207 - There is no requirement for "Action Plans" to be commercially seamless between Regions or RTOs. Although commercial concerns are NOT within NERC's purview, there is no acknowledgement that consistent Action Plans between RAs should be implemented where needed, i.e.- within the same interconnection and/or market to ensure seamless operations.

These processes, procedures or plans are for support of interconnection reliability, they aren't designed to be used to mitigate commercial impacts. There is another standard, "Coordinate Operations" that requires RAs to agree to action plans that require cooperation between two or more RAs.

Electricity Consumers Resource Council

There is no requirement for commercially seamless Action Plans between Regions or RTOs. The Standard should, at least, recognize that consistent Action Plans may have either reliability or commercial implications.

These processes, procedures or plans are for support of interconnection reliability, they aren't designed to be used to mitigate commercial impacts. There is another standard, "Coordinate Operations" that requires RAs to agree to action plans that require cooperation between two or more RAs. *(Note that the Functional Model doesn't recognize RTOs, so this standard is for RAs.)*

- ***Require RAs to implement Action Plans***

Public Service Electric and Gas Company (LSEs)
PSEG Energy Resources & Trade LLC PS
PSEG Power LLC

The RAs should be required to carry out their Action Plan reliability responsibilities in such a manner to ensure seamless operations and markets within their footprints and that of interconnected RAs. (Section 207)

There is no requirement that RAs follow their processes, procedures or plans – this recognizes that the real-time conditions may not match the studied conditions.

These processes, procedures or plans are for support of interconnection reliability, they aren't designed to be used to ensure seamless commercial markets. There is another standard, "Coordinate Operations" that requires RAs to agree to action plans that require cooperation between two or more RAs.

Measures

(b) Measures

(1) The Reliability Authority shall have one or more ~~a~~ documented ~~action plan~~ processes, procedures or plans that address~~es~~ both preventing and mitigating instances of exceeding Interconnection Reliability Operating Limits. The ~~plan~~ processes, procedures or plans shall identify and be coordinated with those entities responsible for taking actions ~~acting~~ and with those entities impacted by such actions.

- ***Clarify Action Plan Expectations***

NPCC

New York Power Authority MED

Northeast Utilities NU

LIPA LIPA (Transmission Owners)

The Action Plans referred to in Section 207 need to be flexible and allow latitude in operator actions

Agreed. There is no requirement that the RA follow its processes, procedures or plans – this recognizes that the real-time conditions may not match the study conditions.

Northeast Utilities NU

The Standards also needs to clarigy the expectations of Section 207. Does Section 207 allow for high level guides/guidelines coupled with highly trained operators to make the proper and timely decision(s) or does it require the existence of a step-by-step procedure for each possible contingency.

The standard was modified to indicate that Action Plans could be processes, procedures or plans. These are all 'defined' terms. Each entity may develop a process, procedure or plan, or any combination of these types of documents.

National Grid USA

New Brunswick Power Corporation NBPC

New York Power Authority NYPA

New York Power Authority MED

Northeast Utilities NU

Nova Scotia Power NSPI

Ontario - Independent Electricity Market Operator IMO

ISO New England Inc ISNE

Section 207, Action Plan. It is National Grid's (NPCC's) (ISO-NE's) position that requiring an Action Plan and its associated steps and procedures for dealing with instances of IROL violations will prove to be restrictive and disallow operators from taking other positive actions than those as outlined in a "plan." National Grid feels that confining operators to a set of steps for an IROL violation may, at face value appear to be laudable, however may not be in the best interest of correcting the IROL violation for the specific set of system conditions that may exist.

Note that although the standard requires RAs to have these documents, the standard does not require RAs to follow these plans. This recognizes that the real-time conditions may not match the study conditions.

City of Lakeland PLKT

Action plans referenced in part 207 not sufficiently defined, ie; plan for what, every possible contingency ? subsets ?

The processes, procedures or plans addressed in this requirement need to be developed to suit the individual RA's needs.

Gainsville Regional Utilities GVL (LSEs)
City of Tallahassee TAL (Transmission Owners)

The Reliability Authority shall have an action plan that identifies actions it shall take or actions it shall direct others to take, to prevent or mitigate instances of exceeding its Interconnection Reliability Operating Limits. From this it looks like the RA will work with the owner to develop the action plans, but from the non-compliance levels an action plan could be developed without input. What good is this if the RA can't perform the mitigation? Seems very broad and burdensome to the RA. How detailed do the plans have to be? This could be very work intensive if detailed plans have to be documented for every single contingency. Is it alright if the action plan is to work with the facility owner to develop and/or implement mitigating plans? 204 already required that actions be taken. Why is there a need to document every possible action to take? Seems like 204 is the real key to protect reliability, not to keep piles of what it scenarios.

The measures indicate that the documents must identify and be coordinated with those entities responsible for acting and with those entities impacted by such actions.

The documents need to be detailed enough so that the RA knows what actions to take/direct others to take under the studied conditions.

The levels of non-compliance are assigned to the RA because the RA is ultimately responsible for ensuring that these documents are developed and in place so that entities know what actions to take.

Real-time conditions don't always match the studied conditions – for this reason, there is no requirement that the RA follow its plans.

Each RA may make the documents as detailed as necessary to suit its needs. If the RA has new system operators with little operating experience and/or an operating system with known weaknesses, then very detailed documents may be needed. If the RA has a very experienced staff and a very 'robust' operating system, the documents may not need to be as detailed.

208 Reliability Authority Directives

Manitoba Hydro Electric Board MHEB (Electricity Brokers, Aggregators, and Marketers)

Manitoba Hydro MHEB (LSEs)

Manitoba Hydro (Transmission Owners)

Standard 208 presumes legal agreements have been put in place to allow the reliability authority to demand actions. We have identified a risk that the presumption of the superiority of the Reliability Authority could have significant safety implications if knowledge of local conditions requires contrary actions to protect equipment or personnel. This risk should be dealt with in these legal documents.

The Reliability Authority Certification Standard includes criteria for the agreements that must be in place defining the Reliability Authority's authority to direct other entities to take actions.

Requirements

City of Tallahassee TAL

The standard does not specify that another RA has to following the directives of an adjacent RA, such as SERC/FRCC border or interface issues.

This standard does not require one RA to follow the directives of another RA. Under the Functional Model, all RAs are created 'equal' – no RA has more authority than another RA. There is another standard, "Coordinate Operations," that includes requirements for RAs to work together when an operating situation requires the actions of more than one RA.

Gainsville Regional Utilities GVL (LSEs)

City of Tallahassee TAL (Transmission Owners)

The standard does not address seams issues. It does not allow the RA to give direction to an entity outside the designated RA area. This is very important regardless if the RA is an entity such as TEC or if the RA is more of the Security (Reliability) Coordinator entity.

Under the Functional Model, issues between Reliability Authority Areas are addressed between the RAs. The Coordination of RA activities is addressed in the Coordinate Operations Standard. The Coordinate Operations standard includes requirements that RAs work together and agree to take certain actions under a range of conditions.

AEP Service Corp -- Transmission System AEP

Generator operators need to be added to the entities listed.

Under the Functional Model, the RA does not give directions to the Generator Operators. Under the Functional Model, the RA directs the Balancing Authority and the Balancing Authority directs the Generator Operator. The Functional Model (page 12 – under Real-time Relationships that the Reliability Authority has with other 'functions:'

> Issues corrective actions (e.g., curtailments or load shedding) to Transmission Operators, Transmission Service Providers, Balancing Authorities, and Interchange Authorities.

The Functional Model (page 18 – under Real-time Relationships that the Balancing Authority has with other 'functions:'

> Directs resources (Generator Operators and Load-Serving Entities) to take action to ensure balance in real time.

Measures

(b) Measures

(1) The responsible entity shall have evidence that it received and followed the Reliability Authority's directives~~. and shall document the directives and actions taken to meet the directives.~~

(2) The responsible entity shall have ~~document via~~ an operations log or other data source, with the following information recorded for each directive it receives relative to an Interconnection Reliability Operating Limit:

(i) Date and time of directive received

(ii) Directive ~~issued~~ received

(iii) Actions taken in response to directive

AEP Service Corp -- Transmission System AEP

Requirement (a)(ii) is repeated again in Measure (b)(i).
The measures have been revised so they read more like measures and less like requirements.

Levels of Non-compliance

Gainsville Regional Utilities GVL (LSEs)
City of Tallahassee TAL (Transmission Owners)

Levels of Non-Compliance - Level four: The responsible entity did not follow the Reliability Authority's directives. If an entity does not follow the RA directive, will the RA have the ability to take action/implement the mitigation plan? If not, other than a financial penalty, it doesn't look like there is any way to make entities comply and reliability can be jeopardized.

If an entity doesn't comply with the RA's directives, then the RA needs to take other actions to preserve the reliability of the Interconnection, up to and including shedding load.

AEP Service Corp -- Transmission System AEP

The levels of non-compliance need to be reviewed to ensure that they accurately reflect how well the directives were followed. Timing of actions taken with regards to when the directives were issued should also be considered.

There is a wide range of possible RA directives – in some scenarios, the RA may direct an entity to take actions within a critical timeframe – in other scenarios, the RA may contact an entity and ask that entity how long it would take to achieve a specific goal. If you have specific suggestions, please submit them when this standard is re-posted for comment.

Sanctions

City of Tallahassee TAL

Under the Sanctions - Fixed Dollars: In reference to the last line; "If those assumptions prove wrong in the future, yet they are made in good faith using good practices, entities should not be harshly penalized for the outcome." Why is there ANY penalty if a best guess was a little off?

The sentence you've referenced is from the Sanctions Table that is part of the Compliance Enforcement Program approved by the NERC Board. The referenced sentence has been taken out of context – it was written in reference to planning standards, not operations-related standards. The set of paragraphs that explain the rational for using flat fines and dollars per MW sanctions are as follows:

> Fixed Dollars
>
> This sanction is used when a letter is not enough and a stronger message is desired. Fixed dollars are typically assigned as a one-time fine that is ideal for measures involving planning-related standards. Many planning actions use forward-looking assumptions. If those assumptions prove wrong in the future, yet they are made in good faith using good practices, entities should not be harshly penalized for the outcome."
>
> Dollars per MW
>
> Dollars per MW sanctions are oriented toward operationally based standards. The MW can be load, generation, or flow on a line. Reasonableness of a sanction needs to be figured into assessing $/MW penalties. Assessing large financial penalties is not the goal, but sending a message with proper emphasis on $$$ can be controlled with the multiplier.

Because the requirement to follow the RA's directives isn't always tied to a certain number of MW, the SDT drafted this standard with "Fixed Dollar" sanctions rather than "Dollars per MW" sanctions.

Other Comments on Standard

- ***Standard Needs Clarity, General Changes***

Alabama Electric Cooperative AEC

The entire standard is to ambiguous and does little to clear up the OSL- OSLV confussion that has lingered for years.

The definition of Cascading Outages has been refined to try to bring more clarity to this standard.

Under the revised definitions, a cascading outage is the uncontrolled successive loss of system elements triggered by an incident at any location which results in the loss of 300 MW or more of networked system load for a minimum of 15 minutes.

American Transmission Company LLC ATC

The standard is not precise enough in defining where it should be applied. More specifically, the standard asks Reliability Authorities to designate facilities to be subject to IROL's, as distinct from SOL's, presumably on the basis of potential "Wide Area Impact," but the meaning of "Wide Area" remains an open question. For example, it remains undetermined whether the largest city or even some multi-state regions would meet the definition of "Wide Area."

The definitions of Cascading Outages and Bulk Electric System have been refined to try to bring more clarity to this standard. The term, 'wide area impact' is not used in this standard, and has been removed from the terms used in the definition of 'cascading outages'. The new definitions provide specific criteria that should allow entities to determine which of their facilities are subject to IROLs.

Under the revised definitions, a cascading outage is the uncontrolled successive loss of system elements triggered by an incident at any location which results in the loss of 300 MW or more of networked system load for a minimum of 15 minutes.

JEA JEA (LSEs)
JEA JEA (Generators)

JEA supports the concepts of this standard, but is voting no because JEA believes the proposed standard in its present form needs more work clarification prior to implementation by the industry.

This comment is not specific enough to provide the SDT with guidance on what needs to be modified.

MAIN

On the surface this standard seems like this is a "no-brainer" except that put into writing it is now too vague and leaves too much room for interpretation.

This comment is not specific enough to provide the SDT with guidance on what needs to be modified.

New York State Public Service Commission

The webcast discussion regarding this proposed standard indicated several outstanding issues that should be addressed by the standard drafting committee.

This comment is not specific enough to provide the SDT with guidance on what needs to be modified.

Aquila, Inc. (Transmission Owners)

This standard seems to lack industry consensus and needs further development before Aquila could vote yes.

This comment is not specific enough to provide the SDT with guidance on what needs to be modified.

Carolina Power & Light Company CPL (Transmission Owners)
Carolina Power & Light Company CPL (LSEs)
Carolina Power & Light Company CPL (Generators)

The Requirements, Measurements, and Levels of Non-compliance are not well linked throughout the standard. It appears that the majority of comments to place the standard in good, logical format were ignored.

The SDT addressed each comment submitted on each posting of this standard. The format used in this standard is a template that was developed under the guidance of NERC's General Counsel.

Gainsville Regional Utilities GVL (LSEs)
City of Tallahassee TAL (Transmission Owners)

201 - 208
Compliance Monitoring Process – There are some inconsistencies in this area. It is indicated that the self-certification is submitted to the Compliance Monitor annually and the Performance-reset period is 12 months from the last violation. Do these match? What does it really mean? Do violations "rack-up" for 12 months? What if there is at least one violation each month? In addition to the time constraints, there should be evidence that the list of facilities subject to IROLS and the list of IROLS are supposed were updated. Does this mean keeping revisions for a certain time period?

There is no mis-match between the self-certification and the Performance-reset period. Although self-certification occurs annually, there are other mechanisms for reviewing compliance during the course of a year. The Compliance Monitor could review performance as part of a routine audit, or as part of a triggered investigation. If an entity has non-compliant performance, the reset period won't re-start until that entity has gone 12 months without an incident of non-compliant performance.

January 2006 – TOP
Kansas City Power & Light KCPL

The levels of compliance sections in these standards should be revised to use all the levels to take into account severeity and reasonableness.

Some requirements lend themselves to using all levels of non-compliance, and the SDT attempted to put in as many levels of non-compliance as practical. This is a very critical standard, and the requirements are critical to reliability.

American Transmission Company LLC ATC

Contrasting operator actions versus documentation, the standard is relatively overly focused on documentation. As a specific example of this, Section 204, which addresses "Actions," permits an IROL shorter than Tv yet still requires documentation of the event (Section 204 (e) (1)). The documentation required by this standard is so burdensome that it risks system operations could become distracted from its primary role of acting on IROL's.

The documentation required in this standard is typically the same documentation made by system operators performing real-time tasks.

- ***Wait for Field Testing***

Western Area Power Administration - CM WACM

It is suggested that this standard be placed through a field test prior to implementation and enforcement. The Operating Limit Definition Task Force has had a field test in place for the last 6 months which yielded zero violation reports. They are in the process of reviewing the reasons for this extreme drop in reporting, and will discuss those findings at the March NERC Operating Committee meeting. I suggest that this standard would benefit in a similar manner

The determination on whether to conduct field testing is made by the Standards Authorization Committee (SAC). The Director-Compliance makes a recommendation to the SAC and the SAC makes the final determination. The Standards Drafting Team does not have a role in the determination of whether to conduct Field Testing .

United States Bureau of Reclamation

Finally the standard has not been tested in a pilot situation to assess how it may operate in practice.

The determination on whether to conduct field testing is made by the Standards Authorization Committee (SAC). The Director-Compliance makes a recommendation to the SAC and the SAC makes the final determination. The Standards Drafting Team does not have a role in the determination of whether to conduct Field Testing .

Pacific Gas & Electric Company PGEU (Electric Generators)

Implementation should address:

Field-testing to identify deficiencies due to oversight. Experience with the WECC RMS has shown that technical violations of a deficient standard impose unnecessary sanctions and/or many hours to prepare responses explaining actions. This imposes an undo burden on industry that has no practical benefit for improving reliability.

The determination on whether to conduct field testing is made by the Standards Authorization Committee (SAC). The Director-Compliance makes a recommendation to the SAC and the SAC makes the final determination. The Standards Drafting Team does not have a role in the determination of whether to conduct Field Testing .

American Transmission Company LLC ATC

This standard should be field tested before implementation, considering the magnitude of the standard's scope, resource requirements, and potentially adverse impact to reliability.

The determination on whether to conduct field testing is made by the Standards Authorization Committee (SAC). The Director-Compliance makes a recommendation to the SAC and the SAC makes the final determination. The Standards Drafting Team does not have a role in the determination of whether to conduct Field Testing .

California Energy Commission

The standard has not been field-tested. Experience with the WECC Reliability Management System (RMS) has demonstrated that much can be learned from field tests to verify that the standard requirements are measurable and enforceable. Results from analysis of field tests should be used to refine the standard before it is implemented and enforced.

The determination on whether to conduct field testing is made by the Standards Authorization Committee (SAC). The Director-Compliance makes a recommendation to the SAC and the SAC makes the final determination. The Standards Drafting Team does not have a role in the determination of whether to conduct Field Testing .

MAIN

There is substantial agreement with one of the WECC concerns about the application of the standard without first testing the provisions of the standard. The concept of a technical study to determine a fix when a limit is exceeded is good. However, it may be impractical to run such a study representing the system conditions in effect at the time of each operating limit violation to assess the consequences to determine if it is a reportable violation. The operator should be concentrating on fixing the problem.

This standard has not been field-tested. Experience has demonstrated that much can be learned from field tests to verify that the standard requirements are measurable and enforceable. Results from analysis of field tests should be used to refine/verify the standard before it is implemented and enforced.
This standard should be field tested before implementation, considering the magnitude of the standard's scope, resource requirements, and potentially adverse impact to reliability

None of the compliance monitoring processes in this standard include asking that the RA conduct a post-mortem technical study. IROLs are established prior to an event occurring and shall be enforceable in real-time. System Operators must operate so that they don't exceed identified IROLs – its not helpful to identify IROLs after-the-fact.

The SOLs that are identified as IROLs must be developed following Standard 600. Under Standard 600, studies are conducted to identify the SOLs as well as the consequences of violating one of these limits. Studies are not required to be conducted after an IROL has been identified and this standard does not require that any entity demonstrate 'after the fact' that a limit was/was not an IROL.

Whether or not existing system conditions match the conditions studied for the original identification of the IROL, the IROL is still an IROL as far as the system operators are concerned. The IROL remains an IROL until the system operators are informed differently.

The determination on whether to conduct field testing is made by the Standards Authorization Committee (SAC). The Director-Compliance makes a recommendation to the SAC and the SAC makes the final determination. The Standards Drafting Team does not have a role in the determination of whether to conduct Field Testing .

WECC

Minnesota Power MP

Public Works Commission Fayetteville PWCF

Southern California Edison SCET

Salt River Project SRP

Tucson Electric Power Company TEPC

Platte River Power Authority TP PRPA

The standard has not been field-tested. Our experience (with the WECC Reliability Management System – RMS) has demonstrated that much can be learned from field tests to verify that the standard requirements are measurable and enforceable. Results from analysis of field tests should be used to refine the standard before it is implemented and enforced.

The determination on whether to conduct field testing is made by the Standards Authorization Committee (SAC). The Director-Compliance makes a recommendation to the SAC and the SAC makes the final determination. The Standards Drafting Team does not have a role in the determination of whether to conduct Field Testing .

Wisconsin Public Service Corporation WPS

This standard has not been field-tested. Results from analysis of field tests should be used to refine/verify the standard before it is implemented and enforced.

The determination on whether to conduct field testing is made by the Standards Authorization Committee (SAC). The Director-Compliance makes a recommendation to the SAC and the SAC makes the final determination. The Standards Drafting Team does not have a role in the determination of whether to conduct Field Testing .

- ***Implementation Plan – Fix Date on page 1 of Standard***

City of Lakeland PLKT

The Q&A document states the Operate Within IROL standard can't be implemented until after the Determine Facility Ratings System Operating Limits and Transfer Capabilities standard is implemented.

The effective date on the cover page of the standard has been revised to conform with the date in the Implementation Plan. It now states that the standard will become effective three months from the date the NERC BOT votes to adopt the standard, but that compliance with the standard will be delayed until after the Determine Facility Ratings Standard has been implemented.

Duke Power DUKE (Electric Generators)

Duke Power DUKE (LSEs)

Duke Power DUKE (Transmission Owners)

The "Effective Date" as defined by this Standard is inconsistent with the associated Implementation Plan. Further, to predicate the implementation of one Standard on another, yet undeveloped Standard, creates unreasonable uncertainty as to the intended implementation and applicability of this Standard.
The effective date on the cover page of the standard has been revised to conform with the date in the Implementation Plan. It now states that the standard will become effective three months from the date the NERC BOT votes to adopt the standard, but that compliance with the standard will be delayed until after the Determine Facility Ratings Standard has been implemented.

The set of standards currently under development has many inter-relationships. We are attempting to complete the standards in a sequence that makes the adoption and implementation logical to the industry – however because each standard is being developed subject to industry input, the actual completion date of any specific standard is impossible to predict.

Electricity Consumers Resource Council

The "Questions and Answers About the Operate Within IROLs Standard" states that the Operate Within Limits Standard cannot be implemented until AFTER the Determine Facility Ratings, System Operating limits and Transfer Capabilities Standard has been implemented. Yet, the Effective Date of this Standard is the first day of the month following NERC Board approval. This conflict must be resolved.

The effective date on the cover page of the standard has been revised to conform with the date in the Implementation Plan. It now states that the standard will become effective three months from the date the NERC BOT votes to adopt the standard, but that compliance with the standard will be delayed until after the Determine Facility Ratings Standard has been implemented.

Manitoba Hydro Electric Board MHEB (Electricity Brokers, Aggregators, and Marketers)

Manitoba Hydro MHEB (LSEs)

Manitoba Hydro (Transmission Owners)

There are a confusing number of dates associated with the standard - these are the "Effective Date", the "Implementation Date" and the "Compliance Date" – only one of which is defined in the standard ("Effective Date"). These should be better explained and clarified in the preamble of the standard.

The effective date on the cover page of the standard has been revised to conform with the date in the Implementation Plan. It now states that the standard will become effective three months from the date the NERC BOT votes to adopt the standard, but that compliance with the standard will be delayed until after the Determine Facility Ratings Standard has been implemented.

WECC

Minnesota Power MP
Public Works Commission Fayetteville PWCF
Southern California Edison SCET
Salt River Project SRP
Tucson Electric Power Company TEPC
Platte River Power Authority TP PRPA
California Energy Commission

The document "Questions and Answers About the Operate Within IROLs Standard" states that: "Several things must be in place before entities are expected to come into full compliance with all of the requirements of this standard. Most importantly, the Operate Within IROLs Standard can't be implemented until after the Determine Facility Ratings, System Operating Limits and Transfer Capabilities standard has been implemented." However, the Effective Date section on page 3 indicates that "This standard will become effective on the first day of the month following the month that the NERC Board of Trustees adopts the standard." These two statements appear to contradict each other.

The effective date on the cover page of the standard has been revised to conform with the date in the Implementation Plan. It now states that the standard will become effective three months from the date the NERC BOT votes to adopt the standard, but that compliance with the standard will be delayed until after the Determine Facility Ratings Standard has been implemented.

American Transmission Company LLC ATC
MAIN

Before this standard can be implemented, the "Determine Facility Ratings, System Operating Limits and Transfer Capabilities" standard must be implemented. However, the effective date of this standard has been set without regard for the effective date of the "Determine Facility Ratings" standard.

The effective date on the cover page of the standard has been revised to conform with the date in the Implementation Plan. It now states that the standard will become effective three months from the date the NERC BOT votes to adopt the standard, but that compliance with the standard will be delayed until after the Determine Facility Ratings Standard has been implemented.

- ***Other Comments on Implementation Plan***

Consumers Energy CETR (TDUs)

Consumers Energy is also concerned that the implementation provisions of this standard does not allow for adequate time for development and training of personnel before compliance is mandated.

The implementation plan provided shows that entities would have 9-15 months beyond the date of BOT Adoption to come into compliance with the requirements in this standard. Most of the measures in the standard are only minor modifications to what is currently being done – extensive training should not be required.

ISO New England Inc ISNE

While ISO New England generally agrees with a quick implementation of the final approved Standard, there is a large amount of specific data that must be collected and stored to meet the full intent of the Standard. Depending upon what the final approved Standard is, this may require additional software and business processes to fully implement. For this reason we believe that an implementation plan must provide a development period for the responsible entities to fully implement the standard.

The implementation plan, page 15 included the following chart. This chart shows that entities would have several months or more to come into full compliance with this standard. The justification for the delay in compliance with each of the measures is provided in pages 16-23 of the Implementation Plan.

Requirement	Implementation Date	Compliance Date
201 - IROL Identification	3 months from BOT adoption	6 months from implementation of Requirement 604
202 – Monitoring	3 months from BOT adoption	6 months from implementation of Requirement 604
203 - Analyses and Assessments	3 months from BOT adoption	6 months from implementation of Requirement 604
204 - Actions	3 months from BOT adoption	6 months from implementation of Requirement 604
205 – Data Specification & Collection	3 months from BOT adoption	9 months from implementation of Requirement 604
206 – Data Provision	3 months from BOT adoption	12 months from implementation of Requirement 604
207 – Action Plan	3 months from BOT adoption	6 months from implementation of Requirement 604
208 – Reliability Authority Directives	3 months from BOT adoption	9 months from implementation of Requirement 604

Cinergy Corporation CIN

Prior to implementation, NERC should not generically assign the responsibilities of the Standard to those currently providing the functions, it should require each Control Area to identify the entity responsible for performing the function of the RA for its Control Area and then require the RA to confirm that responsibility.

Implementing this suggestion is outside the scope of the SDT. Your suggestion was forwarded to the Director-Standards for consideration in the development of the Standards Transition Plan.

Manitoba Hydro Electric Board MHEB (Electricity Brokers, Aggregators, and Marketers)

Manitoba Hydro MHEB (LSEs)

Manitoba Hydro (Transmission Owners)

It is not clear what is the legal standing of the implementation plan; should not this plan be part of the standard itself, so as to be documented, fixed and enforceable?

The members of a standard's Ballot Pool vote to accept the definitions, the standard, the standard's compliance elements and the standard's implementation plan. From ANSI's perspective, the standard is limited to the Requirements and Measures.

If a standard is approved by a Ballot Pool , the Implementation Plan is submitted to the NERC Board of Trustees for its adoption. (Note that the BOT votes to 'adopt' the standard, the definitions, the compliance elements and the implementation plan.) If the implementation plan is adopted and indicates that sections of existing Operating Policies or Planning Standards should be retired, then the Standing Committees will respect the BOT decision and will 'retire' the identified documents as designated in the implementation plan. Similarly, if the approved Implementation Plan indicates that compliance won't be effective until 6 months after the date of the BOT adoption, then those dates would be respected by the Compliance Enforcement Program.

- ***Function Responsible & Functional Model Implementation***

Gainsville Regional Utilities GVL (LSEs)

City of Tallahassee TAL (Transmission Owners)

As previously mentioned, Applicability continues to be an issue. In addition, the inclusion of the Functional Model in the standard implies that the standards will need to be updated every time the functional model changes. This comment also applies to the Implementation Plan.

The SDT cannot guarantee that the Functional Model will never change. However, the SDT can state that the Functional Model is the approved basis for writing the current standards. NERC’s current Policies and Standards were based upon the concept of a control area. Recent events (such as the creation of GENCOs, TRANSCOs and generation-only control areas) have shown that NERC’s vision of control areas is no longer a valid basis for writing standards. The task-based Functional Model is the approved alternative.

The Functional Model defines tasks and relationships. To date the Functional Model’s tasks and relationships remain virtually the same as they were in the original version. The addition of separating the tasks between owner and operator did not invalidate the Functional Model. Neither did the inclusion of the Planning Functions invalidate the Functional Model. If new subdivisions of tasks are required, then the standards will have to be amended appropriately. But to wait until everyone can agree on the future of our industry would commit NERC to permanent inaction.

Most of the changes in the Functional Model have been ‘format’ changes and not content changes. However, as the industry changes, it is possible that the Functional Model will continue to be updated and it is possible that some of the standards will need to be revised to conform with these changes. The alternative is to draft standards without addressing which entities would need to comply with those standards – that’s where we are today. Some entities are performing as Control Areas, but many other entities are no longer operating as a Control Area, and there is great confusion as to which entities are responsible for the existing Operating Policies.

Avista Corp. AVA
Avista Corp. Washington Water Power Division AVWP

The standard puts the responsibility on the RA instead of the path operator. Under the functional model these may be separate entities. The transmission owner and/or path operator should be responsible for maintaining flows within Interconnection Reliability Operating Limits (IROL) not the RA. Combining too much responsibility under the RA will lead to reduced reliability not increased reliability. The transmission owner and/or path operator should not wait for a directive from the RA before taking action. The standard puts another layer between the operation of the path and the reliability of the system.

It is important to keep in mind that a given entity may serve more than one Function.

In its simplest form, a transmission owner may operate only one facility. The Functional Model is designed to address standards at that level. In such an environment, that operator has a very narrow perspective of the transmission system. IROLs can and do go beyond the loading of a single facility. Although the single-facility operator does know how much its ***facility*** can handle, it may not know how much the ***system*** can handle – and more to the point the single-facility operator does not have the ability to do anything about such overloads (except to open the facility – which may or may not solve the problem).

A Transmission Operator that is also responsible for the control of its inter-area tie flows would serve two roles: one as the transmission operator and the other as a Balancing Authority – and therefore be subject to both the Balancing Authorities' and the Transmission Operators' standards. A large Transmission owner may serve three or more roles, e.g. it could also serve as Reliability Authority and a Balancing Authority.

The standard does put the responsibility on the RA. Under the Functional Model, only one 'function' is responsible for any one requirement. Thus – either the RA or the TOP must be responsible for ensuring that IROLs aren't exceeded. The Functional Model provides the following explanation on pages 12-13:

> The Reliability Authority's purview must be broad enough to enable it to calculate Interconnection Reliability Operating Limits, which may be based on the operating parameters of other transmission systems beyond the Transmission Operator's vision. The Transmission Operator is responsible for the reliability of its "local" transmission system, and may not be aware that its system is violating an Interconnection Reliability Operating Limit. Therefore, the Reliability Authority may direct the Transmission Operators or Balancing Authorities to take action to mitigate Interconnection Reliability Operating Limits.

The Functional Model does allow the RA to 'delegate' some of its tasks, thus it is possible for an RA to delegate the task of monitoring an IROL to one of its TOPs.

Under the Functional Model, the TOP is not responsible for IROLs – under the Functional Model the TOP is responsible for controlling its portion of the transmission system so that system operating limits aren't exceeded. The scope of this standard was limited to the subset of SOLs that are IROLs. The SDT recognizes that exceeding **any** SOL is unacceptable, but adding requirements to this standard that address exceeding SOLs is outside the scope of the associated SAR. The SDT is drafting another SAR to address monitoring and operating within SOLs.

Avista Corp. AVA (Transmission Owners)

Avista Corp. Washington Water Power Division AVWP (Generators)

The implementation date is too soon. The standard relies on the role of the Reliability Authority and another standard (Determine Facility Ratings, System Operating Limits and Transfer Capabilities) both of which are still being drafted. The RA functions need to be clearly defined and approved before implementing this standard.

The RA function is defined in the Functional Model - and the Functional Model was approved by the NERC Board of Trustees. Most of the changes to the approved version of the Functional Model are 'format' changes rather than 'content' changes. Waiting for 'final' approval of the revised version of the Functional Model is not practical, since the Functional Model may continue to need to be changed to conform with industry changes that are mandated by entities such as FERC.

City of Lakeland PLKT

STD implies the RA has more authority and poser to act than what the Functional Model describes

Under the Functional Model, the RA has the authority to direct other entities to take reliability-related actions and other entities are required to act in compliance with those directives. Here are some excerpts from the Functional Model:

Requirement	Quotes from Functional Model (pages 11-13)
Identify IROLs	Calculates Interconnection Reliability Operating Limits based on Transmission Owners' and Generator Owners' specified equipment ratings.
Monitor	Monitor all reliability-related parameters within the Reliability Authority Area, including generation dispatch and transmission maintenance plans
Conduct Analyses	Perform reliability analysis (actual and contingency) for the Reliability Authority Area
Actions	Issues corrective actions (e.g., curtailments or load shedding) to Transmission Operators, Transmission Service Providers, Balancing Authorities, and Interchange Authorities.
Data Specification & Collection	Receives facility and operational data from Generator Operators, Load-Serving Entities, Transmission Owners, Generator Owners, Transmission Operators, Distribution Providers. Receives real-time operational information from Balancing Authority and Transmission Operator for monitoring.
Data Provision	(Supporting requirement for data specification requirement)
Action Plans	(Supporting requirement for actions requirement)
RA Directives	(Supporting requirement for actions requirement)

Southern Company Services SOCO (Generators)
Southern Company Services SOCO (Transmission Owners)
Georgia Power Company (LSEs)

The functional model is used in the standards even before it is finalized. This could be an issue.

The Functional Model was and is designed to be the basis for writing the new Reliability Standards. The SDT cannot guarantee that the Functional Model will never change. However, the SDT can state that the Functional Model is the approved basis for writing the current standards. NERC's current Policies and Standards were based upon the concept of a control area. Recent events (such as the creation of GENCOs, TRANSCOs and generation-only control areas) have shown that NERC's vision of control areas is no longer a valid basis for writing standards. The task-based Functional Model is the approved alternative.

The Functional Model defines tasks and relationships. To date the Functional Model's tasks and relationships remain virtually the same as they were in the original version. The addition of separating the tasks between owner and operator did not invalidate the Functional Model. Neither did the inclusion of the Planning Functions invalidate the Functional Model. If new subdivisions of tasks are required, then the standards will have to be amended appropriately. But to wait until everyone can agree on the future of our industry would commit NERC to permanent inaction.

Duke Power DUKE (Electric Generators)
Duke Power DUKE (LSEs)
Duke Power DUKE (Transmission Owners)

The "Applicability" of this Standard to existing entities performing various system functions, as defined in the functional model, prior to the identification and certification of those entities creates unjust confusion and uncertainty as to responsibility and accountability. In this interim period, this creates more uncertainty as to who is responsible and moves the industry to a less defined state.

This is a problem without any single simple solution. The Certification Standards need to ensure that entities applying for certification have the documents and tools in place needed to meet the performance standards – but the performance standards haven't been finalized. The performance Standards need to be developed assuming that entities have met all the criteria in the Certification Standards – but the Certification Standards haven't been finalized. The NERC Board of Trustees has asked the Drafting Teams to move ahead with the development of standards, and that is what we are trying to do. There may need to be some minor changes to both the Certification Standards and these performance standards once all the standards are developed – but having one process wait for the other doesn't seem like a viable solution that will aid the industry in putting into place a set of standards that will support reliability.

Duke Power DUKE (Electric Generators)
Duke Power DUKE (LSEs)
Duke Power DUKE (Transmission Owners)

Is this language intended to preclude CAs from having direct ISN and directly sharing operational data? In the current state, this has become an acceptable approach to ISN data exchange.

This standard doesn't reference the ISN, therefore it neither requires nor precludes an entity from having access to and using the ISN for data exchange.

Duke Power DUKE (Electric Generators)
Duke Power DUKE (LSEs)
Duke Power DUKE (Transmission Owners)

This Standard appears to be much more prescriptive concerning the responsibility of the RA with respect to the current state of the Reliability Coordinators – specifically with respect to the issues concerning "delegation" of responsibilities and the incumbent utility's statutory obligations to serve.

The new standards are intended to be more specific than existing Operating Policies in describing required measures of what constitutes good performance. However the new standards are also less 'prescriptive' because the new standards provide fewer details on 'how' to achieve the required performance.
This standard does give the RA clear authority to direct the actions of entities performing support functions within its Reliability Authority Area. This concept is in support of the Functional Model.

East Kentucky Power Cooperative EKPC

Although the importance of this standard and the excellent work up to this point is recognized, until the relationships and responsibilities of existing Control Areas, Reliability Cooordinators, etc. as they will be defined for entities in the new Functional Model are understood, who will need to comply and how they will comply are unclear. Additionally, this standard relies on Facility Ratings and Operating Limits that are yet undefined in another new standard. Approval of this IROL standard at this time is premature. The others need to come first.

The Functional Model contains an explanation of the Reliability Authority and tries to explain the relationship between the RA (a set of tasks to perform) and the Reliability Coordinator (one type of entity that may perform the duties of an RA). Each entity must decide if it wants to be an RA, and any entity that wants to be an RA must then complete the RA Certification process.

City of Lakeland PLKT

The understanding of the functional model needs to be improved. The RA described in the standard is not active today. The functional model needs to have final approval and be implemented.

The RA tasks defined in the Functional Model are being carried out today, and in that sense there are active RAs today. The difficulty is that the entities carrying out those tasks have differing corporate structures – some are control areas, some are ISOs, and some are Reliability Coordinators.

The Functional Model was approved by the NERC Board of Trustees in June, 2001. There are revisions to the Functional Model that are under consideration, but these revisions primary address 'format' and not 'content' issues. The Standing Committees approved Version 2 of the Functional Model in November, 2003. The Functional Model may continue to undergo changes to conform to changes in the industry. While this is not ideal, there is nothing the Standards Development Team can do about this reality. Waiting until the Functional Model is 'finished' could mean that we may never have a set of reliability standards that is clear enough to support the industry's needs. The NERC Board of Trustees has asked the Drafting Teams to move ahead with the development of standards, and that is what we are trying to do.

City of Lakeland PLKT

Voting on Standards should not take place until Functional Model completely finished and final version approved by BOT.

The Functional Model was approved by the NERC Board of Trustees in June, 2001. There are revisions to the Functional Model that are under consideration, but these revisions primary address 'format' and not 'content' issues. The Standing Committees approved Version 2 of the Functional Model in November, 2003. The Functional Model may continue to undergo changes to conform to changes in the industry. While this is not ideal, there is nothing the Standards Development Team can do about this reality. Waiting until the Functional Model is 'finished' could mean that we may never have a set of reliability standards that is clear enough to support the industry's needs. The NERC Board of Trustees has asked the Drafting Teams to move ahead with the development of standards, and that is what we are trying to do.

City of Lakeland PLKT

The Functional Model needs to be completed and approved before Standards.

The Functional Model was approved by the NERC Board of Trustees in June, 2001. There are revisions to the Functional Model that are under consideration, but these revisions primary address 'format' and not 'content' issues. The Standing Committees approved Version 2 of the Functional Model in November, 2003. The Functional Model may continue to undergo changes to conform to changes in the industry. While this is not ideal, there is nothing the Standards Development Team can do about this reality. Waiting until the Functional Model is 'finished' could mean that we may never have a set of reliability standards that is clear enough to support the industry's needs. The NERC Board of Trustees has asked the Drafting Teams to move ahead with the development of standards, and that is what we are trying to do.

Exelon Energy Delivery EED - PECO & ComEd (LSEs)
Exelon Generation Company LLC EXGN

Based on information passed on in the OWL web cast, there is confusion on what entity assumes responsibility as Reliability Authority (based on the functional model). The industry should not pursue this Standard until all entities clearly understand accountability and responsibility associated with this Standard.

The Functional Model contains a description of the responsibilities of the RA. Some entities are having difficulty trying to determine if they want to assume responsibility of the RA or the TOP. Each entity must make these decisions for itself. The Functional Model was approved by the NERC Board of Trustees in June, 2001. There are revisions to the Functional Model that are under consideration, but these revisions primary address 'format' and not 'content' issues. The Standing Committees approved Version 2 of the Functional Model in November, 2003. The Functional Model may continue to undergo changes to conform to changes in the industry. While this is not ideal, there is nothing the Standards Development Team can do about this reality. Waiting until the Functional Model is 'finished' could mean that we may never have a set of reliability standards that is clear enough to support the industry's needs. The NERC Board of Trustees has asked the Drafting Teams to move ahead with the development of standards, and that is what we are trying to do.

Gainsville Regional Utilities GVL (LSEs)

City of Tallahassee TAL (Transmission Owners)

The question of which entities will be a RA is very critical to considering this standard. If for example, FPL, PEF, TEC or others are all RA's the definition of local area and widespread all have a different view. The standard appears to be written with the RA as a similar entity as the existing Reliability Coordinator. Basically an overseer monitoring a designated area for reliability. The RA as defined in the Functional Model Version 2 does not seem to fit the standard.

To the extent that a Reliability Coordinator does (or is responsible for) all of the tasks defined for an RA, those Reliability Coordinators can be RAs. To the extent that vertically integrated utilities do (or are responsible for) all of those tasks then those utilities may be RAs. The Functional Model defines tasks not corporate structure.

This standard does assume that the entity performing the RA function will have a 'wide area' view and reliability oversight similar to that defined for today's Reliability Coordinators. When the SDT drafted this standard, the SDT did assume that the RA 'function' would replace the RC 'function.' The Functional Model Version 2 supports this assumption. The Functional Model Technical Reference (page 38) includes the following section that addresses the confusion between the RA and the RC:

> "When the Control Area Criteria Task Force (the FMRTG's predecessor) began developing the Functional Model in 1999, it assumed that the Reliability Authority would perform the role of the Reliability Coordinator. The Task Force picked a different term because the RC was specifically defined in relation to control areas, and not BAs, Transmission Operators, Generators, and so on. Indeed, the tasks that comprise the Reliability Authority function align closely with those of today's Reliability Coordinator, though the Model does not include the degree of detail found in the Reliability Coordinator criteria in the Operating Manual."

Gainesville Regional Utilities GVL (Generators)

It iis not clear as to which individual entities are the relaibility authority. Is it each regional Security Coordinator or a Control Area within a security region. This needs clarification.

To the extent that a Reliability Coordinator does (or is responsible for) all of the tasks defined for an RA, those Reliability Coordinators can be RAs. To the extent that vertically integrated utilities do (or are responsible for) all of those tasks then those utilities may be RAs. The Functional Model defines tasks not corporate structure.

While each entity must decide if it wants to become a Reliability Authority, in most cases the Security Coordinator (now called the Reliability Coordinator) can transition to become a Reliability Authority. In some cases, a Control Area may become a Reliability Authority. Each entity must make these decisions for itself, giving consideration to whether it wants to assume the associated responsibilities and giving consideration to the resources required to meet the associated RA Certification standard.

LG&E Energy Transmission Services LGEE

We do not believe the concept of a Reliability Authority has been sufficiently defined and needs clearification before we know what we are voting on.
We are concerned about a lack of clarity on exactly who the "Reliability Authority" is that would

perform this function, especially in light of RTO roles and the proposed NERC functional model definitions.

Each balloter is asked to vote on what is in the standard presented to them - nothing more or less. To the extent that the standard depends on another as yet not fully defined standard requires the balloter to be involved in the process and comment on what should and what should not be in the standard. NERC Director-Standards is responsible for ensuring that ad hoc expectations between standards are effected.

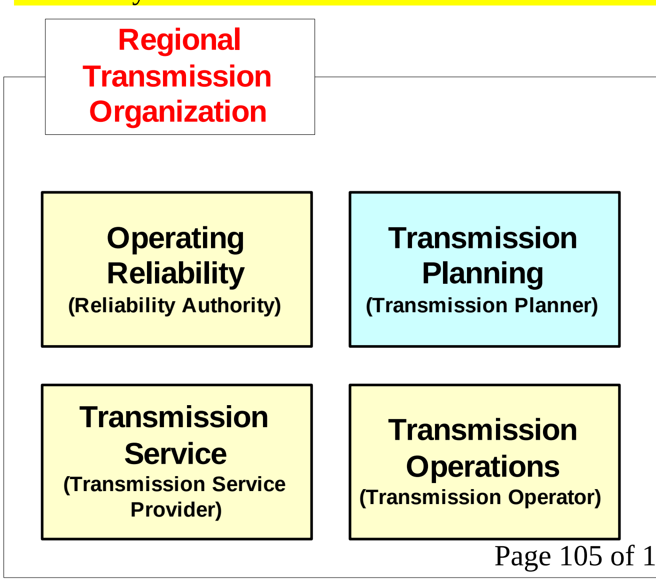
The Functional Model contains a description of the responsibilities of the RA. Some entities are having difficulty trying to determine if they want to assume responsibility of the RA or the TOP. Each entity must make these decisions for itself. The Functional Model was approved by the NERC Board of Trustees in June, 2001. There are revisions to the Functional Model that are under consideration, but these revisions primary address 'format' and not 'content' issues. The Standing Committees approved Version 2 of the Functional Model in November, 2003. The Functional Model may continue to undergo changes to conform to changes in the industry. While this is not ideal, there is nothing the Standards Development Team can do about this reality. Waiting until the Functional Model is 'finished' could mean that we may never have a set of reliability standards that is clear enough to support the industry's needs. The NERC Board of Trustees has asked the Drafting Teams to move ahead with the development of standards, and that is what we are trying to do.

Louisville Gas & Electric LGE (LSEs)

Further detail is required in this SAR to define who is the "Reliability Authority" relative to ISOs/RTOs and the proposed NERC functional model of the different entities functioning in the industry. Otherwise a good standard, but who bears the cost of implementation and execution to achieve the improvement in reliability?

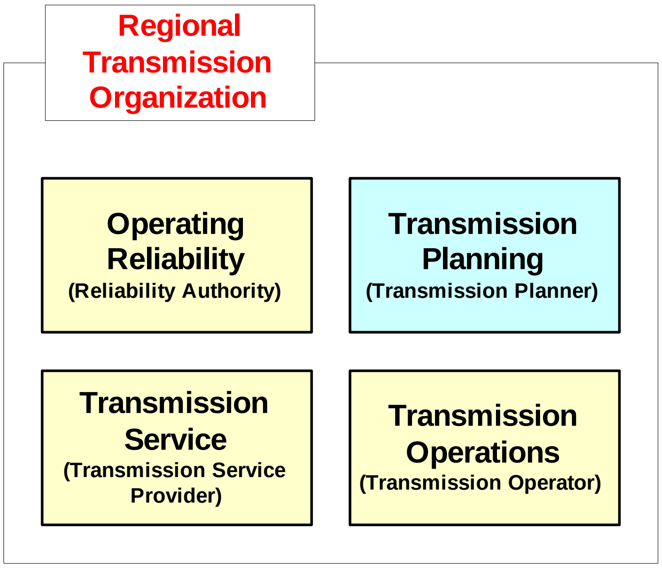
Each balloter is asked to vote on what is in the standard presented to them - nothing more or less. To the extent that the standard depends on another as yet not fully defined standard requires the balloter to be involved in the process and comment on what should and what should not be in the standard. NERC Director-Standards is responsible for ensuring that ad hoc expectations between standards are effected.

The Functional Model contains a description of the responsibilities of the RA. Some entities are having difficulty trying to determine if they want to assume responsibility of the RA or the TOP. Each entity must make these decisions for itself. In some cases, such as in the case of an RTO, one entity may perform several functions. This is a diagram from the Functional Model Technical Document. It shows how one RTO may perform several of the functions in the Functional Model. This is not a 'prescription' for all RTOs – each RTO must decide what functions it wants to perform.



The entity that registers and is certified by NERC assumes the responsibilities and costs. Addressing the cost of implementation is outside the scope of the SDT.

Louisville Gas & Electric LGE (Electric Generators)



Discussion has generated concern in regards to a lack of clarity on exactly who the "Reliability Authority" will be that performs this function, especially in light of ISO/RTO roles and the proposed NERC functional model definitions.

Each balloter is asked to vote on what is in the standard presented to them - nothing more or less. To the extent that the standard depends on another as yet not fully defined standard requires the balloter to be involved in the process and comment on what should and what should not be in the standard. NERC Director-Standards is responsible for ensuring that ad hoc expectations between standards are effected.

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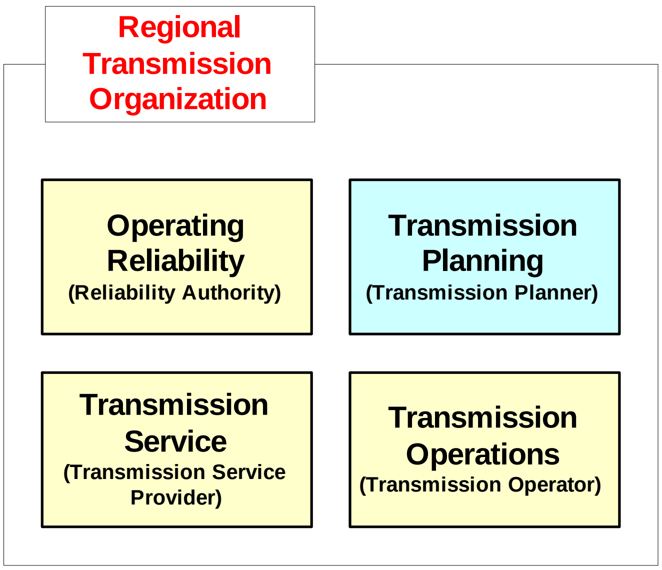
Louisville Gas & Electric LGE (Electricity Brokers, Aggregators, and Marketers)

Concerned about a lack of clarity on exactly who the "Reliability Authority" is that would perform this function, especially in light of RTO roles and the proposed NERC functional model definitions.

Each balloter is asked to vote on what is in the standard presented to them - nothing more or less. To the extent that the standard depends on another as yet not fully defined standard requires the balloter to be involved in the process and comment on what should and what should not be in the standard. NERC Director-Standards is responsible for ensuring that ad hoc expectations between standards are effected.



The Functional Model contains a description of the responsibilities of the RA. Some entities are having difficulty trying to determine if they want to assume responsibility of the RA or the TOP. Each entity must make these decisions for itself. In some cases, such as in the case of an RTO, one entity may perform several functions. This is a diagram from the Functional Model Technical Document. It shows how one RTO may perform several of the functions in the Functional Model. This is not a 'prescription' for all RTOs – each RTO must decide what functions it wants to perform.

Florida Power & Light FPL

FRCC

JEA JEA (Transmission Owners)
Reedy Creek Improvement District RC (LSEs)
Reedy Creek Improvement District RC (TDUs)
Reedy Creek Improvement District RC (Generators)
Reedy Creek Improvement District Marketing RCM (Brokers)
Seminole Electric Cooperative SEC (TDUs)
Seminole Electric Cooperative SEC (Generators)
Seminole Electric Cooperative SEC (Brokers)
Kissimmee Utility Authority
Orlando Utilities Commission OUCT
Tampa Electric Company TEC (LSEs)
Tampa Electric Company TEC (Brokers)
Carolina Power & Light Company CPL (Transmission Owners)
Carolina Power & Light Company CPL (LSEs)
Carolina Power & Light Company CPL (Generators)

The understanding of the Reliability Authority is very critical in interpreting this standard. It appears to us that this standard is written with the RA being the entity today that is the Reliability Coordinator. This confusion was discussed on the Web cast conference call, and it was stated by the Chair of the drafting team, that the RA is not the RC of today. The RA in this standard needs "wide area oversight" to perform the requirements of this standard. We have concern, especially with requirement 208, about how a RA (who is not a RC of today) can issue directives to TO's, BA's, IA's and other RA's if they are not within their reliability area. If the functional model allows an individual CA/TO of today to be a RA tomorrow, it looks like they are giving directives to themselves. So it looks like the RA as defined in version 2 of the functional model does not fit the needs of this standard. That may be more of a problem with interpretation of the functional model than this standard, but until that confusion is cleared up, we have trouble approving this draft.

In the case cited above, the RA is also a BA and a TOP. As such that entity is responsible to effect all of the tasks for the three functions. In that case the RA has the responsibility and would need to ensure that it had the capability to comply with all of those performance requirements.

To the extent that a Reliability Coordinator does (or is responsible for) all of the tasks defined for an RA, those Reliability Coordinators can be RAs. To the extent that vertically integrated utilities do (or are responsible for) all of those tasks then those utilities may be RAs. The Functional Model defines tasks not corporate structure.

As has been shown through the August 14 Blackout Investigation, not all of today's Reliability Coordinators are created equal. Some of today's RC's have wide area monitoring capabilities with clearly defined lines of authority established, but other RC's don't have the same capabilities. This standard was written assuming that the RA would perform the duties assigned to the RA in the Functional Model.

This standard does assume that the entity performing the RA function will have a 'wide area' view and reliability oversight similar to that defined for today's Reliability Coordinators. When the SDT drafted this standard, the SDT did assume that the RA 'function' would replace the RC 'function.' The Functional Model Version 2 supports this assumption. The Functional Model

Technical Reference (page 38) includes the following section that addresses the confusion between the RA and the RC:

> "When the Control Area Criteria Task Force (the FMRTG's predecessor) began developing the Functional Model in 1999, it assumed that the Reliability Authority would perform the role of the Reliability Coordinator. The Task Force picked a different term because the RC was specifically defined in relation to control areas, and not BAs, Transmission Operators, Generators, and so on. Indeed, the tasks that comprise the Reliability Authority function align closely with those of today's Reliability Coordinator, though the Model does not include the degree of detail found in the Reliability Coordinator criteria in the Operating Manual."

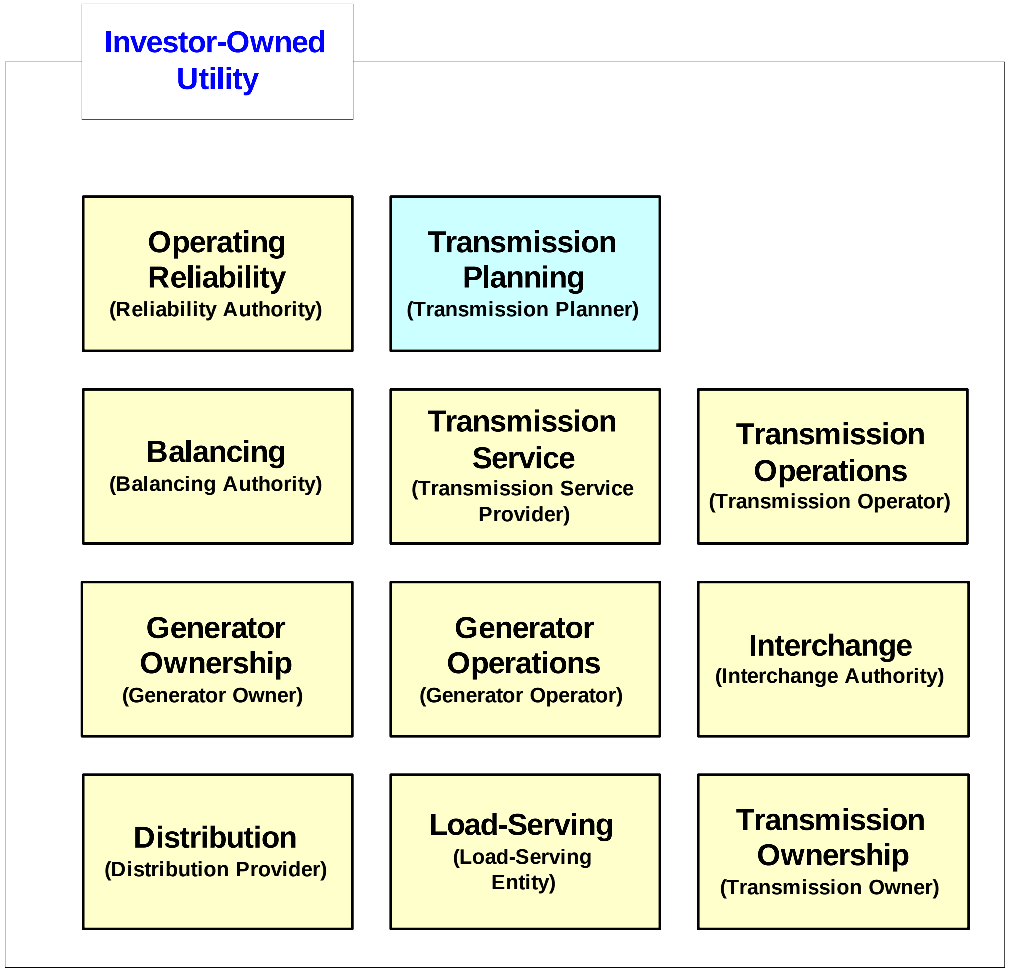
Great River Energy GRE

I also need additional clarification on who is the Reliability Authority. Is this the current Reliability Coordinator or is this still a Control Area function?

To the extent that a Reliability Coordinator does (or is responsible for) all of the tasks defined for an RA, those Reliability Coordinators can be RAs. To the extent that vertically integrated utilities do (or are responsible for) all of those tasks then those utilities may be RAs. The Functional Model defines tasks not corporate structure.

While each entity must decide if it wants to become a Reliability Authority, in most cases the Security Coordinator (now called the Reliability Coordinator) can transition to become a Reliability Authority. In some cases, a Control Area may become a Reliability Authority. Each entity must make these decisions for itself, giving consideration to whether it wants to assume the associated responsibilities and giving consideration to the resources required to meet the associated RA Certification standard.

Some entities will perform several functions, as shown in the "Roll up" examples provided in the Functional Model Technical Discussions document. Here is an example:



Bonneville Power Administration Transmission BPAT

It is our understanding that the Reliability Authority can delegate the function of calculating IROLs. If that is true, it would be good to clarify that possibility.

The Functional Model Technical Discussions document includes a discussion about delegating tasks. Duplicating this discussion in each of the standards would be redundant.

MAIN

Based on information passed on in the OWL web cast, there is confusion on what entity assumes responsibility as Reliability Authority (based on the Functional Model). The industry should not pursue this Standard until all entities clearly understand accountability and responsibility associated with this Standard.
Who will be the Reliability Authority and the Reliability Coordinator in the new NERC functional model will drive this standard to a revision draft.

To the extent that a Reliability Coordinator does (or is responsible for) all of the tasks defined for an RA, those Reliability Coordinators can be RAs. To the extent that vertically integrated utilities do (or are responsible for) all of those tasks then those utilities may be RAs. The Functional Model defines tasks not corporate structure.

As has been shown through the August 14 Blackout Investigation, not all of today's Reliability Coordinators are created equal. Some of today's RC's have wide area monitoring capabilities with clearly defined lines of authority established, but other RC's don't have the same capabilities. This standard was written assuming that the RA would perform the duties assigned to the RA in the Functional Model.

This standard does assume that the entity performing the RA function will have a 'wide area' view and reliability oversight similar to that defined for today's Reliability Coordinators. When the SDT drafted this standard, the SDT did assume that the RA 'function' would replace the RC 'function.' The Functional Model Version 2 supports this assumption. The Functional Model Technical Reference (page 38) includes the following section that addresses the confusion between the RA and the RC:

> "When the Control Area Criteria Task Force (the FMRTG's predecessor) began developing the Functional Model in 1999, it assumed that the Reliability Authority would perform the role of the Reliability Coordinator. The Task Force picked a different term because the RC was specifically defined in relation to control areas, and not BAs, Transmission Operators, Generators, and so on. Indeed, the tasks that comprise the Reliability Authority function align closely with those of today's Reliability Coordinator, though the Model does not include the degree of detail found in the Reliability Coordinator criteria in the Operating Manual."

Midwest Independent Transmission System Operator, Inc.

The industry and the Standard needs to deal with the reality of the existence of Reliability Coordinators and define their role (Based on the informational Webcast, the drafting team's vision is that the RA is the local operator). There currently exists two tiers of control in the grid, local first response from transmission operators and BAs and a higher level-wider area control by Reliability Coordinators.

The Reliability standard defines tasks that must be carried out at various levels. Those responsibilities are defined in the standard. The RA has the responsibility for ensuring reliability is maintained. To the extent that the RA delegates control responsibility among the entities under its purview, that RA is still responsible for the outcome. It is strictly up to that registered RA how to carry out its tasks.

To the extent that a Reliability Coordinator does (or is responsible for) all of the tasks defined for an RA, those Reliability Coordinators can be RAs. To the extent that vertically integrated utilities do (or are responsible for) all of those tasks then those utilities may be RAs. The Functional Model defines tasks not corporate structure.

As has been shown through the August 14 Blackout Investigation, not all of today's Reliability Coordinators are created equal. Some of today's RC's have wide area monitoring capabilities with clearly defined lines of authority established, but other RC's don't have the same capabilities. This standard was written assuming that the RA would perform the duties assigned to the RA in the Functional Model.

This standard does assume that the entity performing the RA function will have a 'wide area' view and reliability oversight similar to that defined for today's Reliability Coordinators. When the SDT drafted this standard, the SDT did assume that the RA 'function' would replace the RC 'function.' The Functional Model Version 2 supports this assumption. The Functional Model

Technical Reference (page 38) includes the following section that addresses the confusion between the RA and the RC:

> "When the Control Area Criteria Task Force (the FMRTG's predecessor) began developing the Functional Model in 1999, it assumed that the Reliability Authority would perform the role of the Reliability Coordinator. The Task Force picked a different term because the RC was specifically defined in relation to control areas, and not BAs, Transmission Operators, Generators, and so on. Indeed, the tasks that comprise the Reliability Authority function align closely with those of today's Reliability Coordinator, though the Model does not include the degree of detail found in the Reliability Coordinator criteria in the Operating Manual."

Minnesota Power MP

There is lack of role clarity regarding coordination of responsibility (and liability) for IROL's.

The RA is responsible for ensuring that the Reliability Authority Area under its control is operated so that IROLs are not exceeded. The RA may delegate some of its tasks, but may not delegate the responsibility for accomplishing those tasks.

Minnesota Power MP

Also, in the MAPP region, the St. Paul Reliability Authority function currently provides services for MISO members, non-jurisdictional entities and non-MISO entities. Some of the non-jurisdictional entities have had traditional "first responder" responsibilities (Policies 2, 4 and 5) because it has been determined that they are the ones most able to quickly restore the system to a safe state. The roles of all such entities with regard to proposed standard 200 would need to be understood.
As further authority for managing such operations transfers to the Reliability Authority, the accountability and legal liability that should accompany such authority must also be transferred.

The Functional Model contains a description of the responsibilities of the RA. Some entities are having difficulty trying to determine if they want to assume responsibility of the RA or the TOP. Each entity must make these decisions for itself.

The Certification Standards (For the RA, Balancing Authority, IA and TOP Functions) should contain requirements that formal agreements be in place that delineate the RAs authority to direct other entities to take actions to preserve the reliability of the interconnection.

Mirant Americas Energy Marketing LP MAEM

The standard does not identify the Compliance Monitor. Is the RRC the monitor? NERC? Certainly have a problem with a RRC monitoring a RA when it is the same entity (e.g., MAAC/PJM).

The Functional Model Technical Discussion includes the following explanation of the Compliance Monitor:

> Today, the Regional Councils are the Compliance Monitors in NERC. The Regional compliance plans are audited by the NERC organization.
>
> In those situations where the Compliance Monitor is also the organization performing a reliability service or operating function (such as a Regional Council that is also the Reliability Authority), then the Compliance Monitor for that function should be a third party that is unaffiliated with that organization.

South Carolina Electric & Gas Company SCEG

This standard assumes that all RAs are large enough to affect the interconnection as a whole. An IROL is defined as a limit that if exceeded could lead to instability, uncontrolled separation, etc... that adversely impacts the reliability of the bulk transmission system. Until all RAs have been determined, there is no way of determining if this requirement is applicable to them. The standard does not address the situation where this requirement is not applicable, and assumes that all RAs will have at least one facility subject to an IROL. This is important because an RA that is small enough can blackout its entire system without causing an uncontrolled separation or blackout for the rest of the interconnection.

The Functional Model does not define "large enough'. If the registered entity can perform the tasks, then the entity will be certified as an RA. By definition, the calculation and correction of violations of IROLs is an RA responsibility – it may be a task that the RA delegates to some other entity, but it still is the RA's responsibility.

The Functional Model includes the following description (pages 12-13):

> **Special Considerations**
>
> The Reliability Authority's purview must be broad enough to enable it to calculate Interconnection Reliability Operating Limits, which may be based on the operating parameters of other transmission systems beyond the Transmission Operator's vision. The Transmission Operator is responsible for the reliability of its "local" transmission system, and may not be aware that its system is violating an Interconnection Reliability Operating Limit. Therefore, the Reliability Authority may direct the Transmission Operators or Balancing Authorities to take action to mitigate Interconnection Reliability Operating Limits.

Southeastern Electric Reliability Council

References to the Functional Model are not current and should be.

The references have been updated as suggested.

- ***Concerns About Other Standards***

Pacific Gas & Electric Company PGEU (Electric Generators)

This posted Standard 200 will have implementation problems. It defines Interconnection Reliability Operating Limit (IROL) to be "a system operating limit which, if exceeded, could lead to instability, uncontrolled separation, or cascading outages that adversely impact the reliability of the bulk transmission system". Its supporting documents also state that the IROL is a subset of the System Operating Limits to be determined according to Standard 600 – Determine Facility Ratings, System Operating Limits (SOL), and Transfer Capabilities, now being drafted. Standard 600 requires that the SOL be determined such that, among other things, all Facilities are operating within their applicable thermal, frequency and voltage limits, in addition to avoidance of instability, uncontrolled separation, or cascading. As such, this Standard 200 could be operating to limits different from the requirements set forth in Standard 600. This leaves the Reliability Authority in an untenable position – it would either have to operate to a set of IROLs that would not meet the requirements in Standard 600, or a set of IROLs that are different than required by Standard 200.

IROLs are a subset of SOLs – they aren't in conflict with one another.

Avista Corp. AVA (Transmission Owners)

Avista Corp. Washington Water Power Division AVWP (Generators)

The implementation date is too soon. The standard relies on the role of the Reliability Authority and another standard (Determine Facility Ratings, System Operating Limits and Transfer Capabilities) both of which are still being drafted. The RA functions need to be clearly defined and approved before implementing this standard.

The Determine Facility Ratings, System Operating Limits and Transfer Capabilities standard is expected to be balloted before this standard is re-posted for ballot.

The Functional Model contains a description of the responsibilities of the RA. Some entities are having difficulty trying to determine if they want to assume responsibility of the RA or the TOP. Each entity must make these decisions for itself.

Florida Power & Light FPL

FRCC

JEA JEA (Transmission Owners)

Reedy Creek Improvement District RC (LSEs)

Reedy Creek Improvement District RC (TDUs)

Reedy Creek Improvement District RC (Generators)

Reedy Creek Improvement District Marketing RCM (Brokers)

Seminole Electric Cooperative SEC (TDUs)

Seminole Electric Cooperative SEC (Generators)

Seminole Electric Cooperative SEC (Brokers)

Kissimmee Utility Authority

Orlando Utilities Commission OUCT

Tampa Electric Company TEC (LSEs)

Tampa Electric Company TEC (Brokers)

The implementation plan states (pg 8) that this standard would not be implemented until after the Determine Facility Ratings standard has been implemented. If this is true, it does not make sense to approve this, especially with outstanding issues, until after the Determine Facility Ratings standard is completed and approved. Also, on the Web cast, when we asked about the ability of the RA to direct other RA's (it is not stated in 208), we were told that the Coordinate Operations Standard would take care of that. Does that mean that this standard is also dependent on the Coordinate Operations standard being in place first?

The implementation date was revised to reflect the same dates provided in the associated Implementation Plan.

These new standards are not 'stand-alone' – there are many inter-dependencies between these standards – and the industry needs to recognize that it will not be practical to 'wait' for one standard to be completed before finalizing another standard. Because these standards are being developed in parallel, rather than in series, the SDTs don't have control over the completion of any other standard. The NERC BOT directed the teams to proceed with development of standards without delay – and that is what the SDTs are trying to do. If NERC had 20 years to develop a new set of standards, then it would be better to develop the standards 'one at a time' – but NERC doesn't have 20 years to develop a new set of standards.

Wisconsin Energy Corporation - PM WEC

The effective date of the standard should not be before all prerequisites have been met.

The implementation date was revised to reflect the same dates provided in the associated Implementation Plan. The Determine Facility Ratings Standard is expected to be balloted before this standard.

Southeastern Electric Reliability Council

The Standard needs to recognize the link between it and the Determine Facility Ratings Standard. This standard should be delayed until the Determine Facility Ratings Standard has been released for vote.

The Determine Facility Ratings, System Operating Limits and Transfer Capabilities standard is expected to be balloted before this standard is re-posted for ballot.

Pacific Gas & Electric Company PGEU (Electric Generators)

Implementation should address:

Identification of all related standards that must be in place to be enforceable and clearly state what requirements are in force upon approval of each related standard.

These new standards are not ‘stand-alone’ – there are many inter-dependencies between these standards – and the industry needs to recognize that it will not be practical to ‘wait’ for one standard to be completed before finalizing another standard. Because these standards are being developed in parallel, rather than in series, the SDTs don’t have control over the completion of any other standard. The NERC BOT directed the teams to proceed with development of standards without delay – and that is what the SDTs are trying to do. If NERC had 20 years to develop a new set of standards, then it would be better to develop the standards ‘one at a time’ – but NERC doesn’t have 20 years to develop a new set of standards.

Gainsville Regional Utilities GVL (LSEs)
City of Tallahassee TAL (Transmission Owners)

The information provided in the Q&A document and the Implementation Plan indicates that the Operate within Limits will not be implemented until the Determine Facilities Ratings Standard (STD 600) has been implemented. This leads to the following questions:
Why balloting so early? Shouldn’t STD 600 be adopted prior to or in conjunction with the IROL standard?

How do the entities know how to establish IROLs with out determining ratings and limits? In addition, there is no common process for developing an IROL and corresponding Tv. It appears from a review of STD 600 that this has not been covered in either standard.
It is unclear if an IROL event is initiated pre-contingency or post-contingency.

The Determine Facility Ratings, System Operating Limits and Transfer Capabilities standard is expected to be balloted before this standard is re-posted for ballot.

The first requirement of this standard was revised to add a reference to the Determine Facility Ratings, System Operating Limits and Transfer Capabilities standard. The reference states that IROLs are a subset of the System Operating Limits developed under the Determine Facility Ratings, System Operating Limits and Transfer Capabilities standard.

IROL's are based on system operating limits that are developed based on study criteria identified in the Determine Facility Ratings, System Operating Limits and Transfer Capabilities standard. IROLs are developed based on studies of pre- contingency situations and are updated in real time to address changes in system topology such as a loss of a line or a unit trip

Southern Company Services SOCO (Generators)
Southern Company Services SOCO (Transmission Owners)
Carolina Power & Light Company CPL (Transmission Owners)
Carolina Power & Light Company CPL (LSEs)
Carolina Power & Light Company CPL (Generators)
Georgia Power Company (LSEs)

Standard 200 and the Determine Facility Ratings Standard are inherently strongly linked. However, there is little verbiage in Standard 200 referencing this linkage. In addition, the Determine Facility Ratings Standard is not yet finalized or approved so there is no way to know what will be in the final version. Since many of the underlying principles of Standard 200 relies on the Determine Facility Ratings Standard, the fact that the basis for much of Standard 200 in not approved creates a large unknown. For these reasons, the OPS feels that the Determine Facility Ratings Standard needs to be approved PRIOR to Standard 200.

The first requirement of this standard was revised to add a reference to the Determine Facility Ratings, System Operating Limits and Transfer Capabilities standard. The reference states that IROLs are a subset of the System Operating Limits developed under the Determine Facility Ratings, System Operating Limits and Transfer Capabilities standard.

The Determine Facility Ratings, System Operating Limits and Transfer Capabilities standard is expected to be balloted before this standard is re-posted for ballot.

Cinergy Corporation CIN

The term IROL and its definition remain confusing and leave room for interpretation. Until the requirements for Standard 600 have been agreed upon by the industry, it is difficult to approve this Standard which remains incomplete until Standard 600 is approved. Standard 600 does not even refer to the term IROL.

The first requirement of this standard was revised to add a reference to the Determine Facility Ratings, System Operating Limits and Transfer Capabilities standard. The reference states that IROLs are a subset of the System Operating Limits developed under the Determine Facility Ratings, System Operating Limits and Transfer Capabilities standard.

The Determine Facility Ratings, System Operating Limits and Transfer Capabilities standard is expected to be balloted before this standard is re-posted for ballot.

City of Lakeland PLKT

Should not approve until STD 600 has been completed and approved as this STD dependant on 600.

The Determine Facility Ratings, System Operating Limits and Transfer Capabilities standard is expected to be balloted before this standard is re-posted for ballot.

Carolina Power & Light Company CPL (Transmission Owners)
Carolina Power & Light Company CPL (LSEs)
Carolina Power & Light Company CPL (Generators)

The implementation plan states (pg 8) that this standard would not be implemented until after the Determine Facility Ratings standard has been implemented. If this is true, it does not make sense to approve this, especially with outstanding issues, until after the Determine Facility Ratings standard is completed and approved.

The Determine Facility Ratings, System Operating Limits and Transfer Capabilities standard is expected to be balloted before this standard is re-posted for ballot.

Pacific Gas & Electric PGAE

This posted Standard 200 may be confusing to implement. It defines Interconnection Reliability Operating Limit (IROL) to be "a system operating limit which, if exceeded, could lead to instability, uncontrolled separation, or cascading outages that adversely impact the reliability of the bulk transmission system". Its supporting documents also state that the IROL is a subset of the System Operating Limits to be determined according to Standard 600 – Determine Facility Ratings, System Operating Limits (SOL), and Transfer Capabilities, now being drafted. Standard 600 requires that the SOL be determined such that, among other things, all Facilities are operating within their applicable thermal, frequency and voltage limits, in addition to avoidance of instability, uncontrolled separation, or cascading. As such, this Standard 200 could be operating to limits different from the requirements set forth in Standard 600. This leaves the Reliability Authority in an untenable position – it would either have to operate to a set of IROLs that would not meet the requirements in Standard 600, or a set of IROLs that are different than required by Standard 200.

There is no conflict between these standards. Standard 200 was revised to add the following reference to Standard 600:

> Each IROL is developed by following the requirements in the Determine Facility Ratings, System Operating Limits and Transfer Capabilities Standard. Standard 600.

City of Tallahassee TAL

IROLs will be defined by the unapproved standard "Determine Facility Ratings...". I would prefer to approve the supporting documents before we approve this document. (Coordinated Operations will be another one that may be needed before this one.) Although the Implementation Plan states Prerequisite Approvals, how can the effective date be the "first day of the month following the month that the NERC Board of Trustees adopts the standard" if the supporting documents are not approved first. It does not specify what are ALL the supporting documents.

These new standards are not 'stand-alone' – there are many inter-dependencies between these standards – and the industry needs to recognize that it will not be practical to 'wait' for one standard to be completed before finalizing another standard. Because these standards are being developed in parallel, rather than in series, the SDTs don't have control over the completion of any other standard. The NERC BOT directed the teams to proceed with development of standards without delay – and that is what the SDTs are trying to do. If NERC had 20 years to develop a new set of standards, then it would be better to develop the standards 'one at a time' – but NERC doesn't have 20 years to develop a new set of standards.

Mirant Americas Energy Marketing LP MAEM

This standard relies on the development of other standards (such as Std. 600 - Determine Facility Ratings, etc.) before it can be implemented. As such, I don't want to pass a standard that is contingent upon the future development of other standards. Along these same lines of thinking, language in the Effective Date and Applicability sections (page 3 of 22) is at a minimum unclear if not contradictory.

These new standards are not ‘stand-alone’ – there are many inter-dependencies between these standards – and the industry needs to recognize that it will not be practical to ‘wait’ for one standard to be completed before finalizing another standard. Because these standards are being developed in parallel, rather than in series, the SDTs don’t have control over the completion of any other standard. The NERC BOT directed the teams to proceed with development of standards without delay – and that is what the SDTs are trying to do. If NERC had 20 years to develop a new set of standards, then it would be better to develop the standards ‘one at a time’ – but NERC doesn’t have 20 years to develop a new set of standards.

The ‘effective date’ was modified to clarify the contradiction.

Entergy EES (Transmission Owners)

STANDARDS DEVELOPMENT – LACK OF COORDINATION OF RESPONSIBILITIES AMONG INDUSTRY ENTITIES

NERC is in the process of converting its Operating Manual to standards. The development of each standard is being done by separate teams, which will lead to disjoint standards. The two standards should be developed and voted on at the same time to ensure proper coordination - Determine Facility Ratings, Operating Limits and Transfer Capability, and this Operate Within IROL standard.

The Determine Facility Ratings, System Operating Limits and Transfer Capabilities standard is expected to be balloted before this standard is re-posted for ballot.

These new standards are not ‘stand-alone’ – there are many inter-dependencies between these standards – and the industry needs to recognize that it will not be practical to ‘wait’ for one standard to be completed before finalizing another standard. Because these standards are being developed in parallel, rather than in series, the SDTs don’t have control over the completion of any other standard. The NERC BOT directed the teams to proceed with development of standards without delay – and that is what the SDTs are trying to do. If NERC had 20 years to develop a new set of standards, then it would be better to develop the standards ‘one at a time’ – but NERC doesn’t have 20 years to develop a new set of standards.

WECC
Minnesota Power MP
Public Works Commission Fayetteville PWCF
Southern California Edison SCET
Salt River Project SRP
Tucson Electric Power Company TEPC
Platte River Power Authority TP PRPA
California Energy Commission

In our opinion, this standard as written invalidates the ratings, transfer capabilities, and limits established under the draft "Standard 600 – Determine Facility Ratings, System Operating Limits, and Transfer Capabilities" because it only provides for enforcement of "Interconnected Reliability Operating Limits," which are the limits that, when exceeded, "could lead to instability, uncontrolled separation, or cascading outages that adversely impact the reliability of the bulk transmission system." The current draft of Standard 600 does not mention "Interconnected Reliability Operating Limits."

IROLs are a subset of SOLs – they aren't in conflict with one another. The first requirement of this standard was revised to add a reference to the Determine Facility Ratings, System Operating Limits and Transfer Capabilities standard. The reference states that IROLs are a subset of the System Operating Limits developed under the Determine Facility Ratings, System Operating Limits and Transfer Capabilities standard.

- ***Comments about Scope***

Minnesota Power MP

In the MAPP region, the North Dakota and Manitoba to USA flowgates can be constrained by either thermal limits or stability limits. How could proposed standard 200 be approved for the stability attributes of these flowgates, without consideration of how the thermal attributes of these flowgates will be administered?

Thermal limits and stability limits can be IROLs if operating outside of these limits could lead to instability, cascading outages or uncontrolled separation that adversely impacts the interconnection. If operating outside of these limits does not lead to instability, cascading outages or uncontrolled separation, then these limits are not IROLs.

Idaho Power Company IPCO

Standard unduly restricts unacceptable operation to cascading outages.

The scope of this standard was limited to the subset of SOLs that are IROLs. The SDT recognizes that exceeding **any** SOL is unacceptable, but adding requirements to this standard that address exceeding SOLs is outside the scope of the associated SAR. The SDT is drafting another SAR to address monitoring and operating within SOLs.

Entergy EES (Transmission Owners)

GOOD UTILITY PRACTICE

This standard ignores the concept of Good Utility Practice. The authors of the standard state:

"There is no common definition for Good Utility Practice – consequently it is not possible to enforce compliance with Good Utility Practice."

Reliability Authorities must be held accountable to the concept of Good Utility Practice even if there is no common definition. Without adherence to this requirement the industry will continue to slowly spiral down in reliability since those in authority will not be held accountable for their actions. FERC has supplied the industry with a definition of Good Utility Practice, which should be good enough for use in NERC standards. Entergy insists this standard not be approved until this standard includes the requirement that RAs conform to Good Utility Practice, preferably as defined by FERC, and all industry participants be held accountable to it.

The definition of "Good Utility Practice" provided by FERC is very subjective and would not meet the requirements set for NERC Reliability Standards.

FERC's definition of Good Utility Practice is repeated here:

> Any of the practices, methods, and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods, and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety, and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act, to the exclusion of all others, but rather to be a range of acceptable practices, methods, or acts generally accepted in the region. Good Utility Practice shall include, but not be limited to, compliance with Applicable Laws and Regulations, Applicable Standards, the National Electric Safety Code, and the National Electrical Code, as they may be amended from time to time, including the criteria, rules and standards of any successor organizations.

Manitoba Hydro Electric Board MHEB (Electricity Brokers, Aggregators, and Marketers)

Manitoba Hydro MHEB (LSEs)

Manitoba Hydro (Transmission Owners)

NERC need to make a clear statement as to which entities will be responsible for ensuring operation within all of the System Operating Limits, since violations of these limits can lead to equipment damage and increase the risk of more violations and even IROL violations.

The scope of this standard was limited to the subset of SOLs that are IROLs. The SDT recognizes that exceeding **any** SOL is unacceptable, but adding requirements to this standard that address exceeding SOLs is outside the scope of the associated SAR. The SDT is drafting another SAR to address monitoring and operating within SOLs.

Midwest Independent Transmission System Operator, Inc.

Minnesota Power MP

The only requirement in the standard for Control Areas (BAs) and Transmission Operators is to provide data and follow the direction of the RA (which most people assume is the Reliability Coordinator, but there's not agreement on that). There is no requirement for the TO or BA to take any action (other than wait for the RA to direct them).
The scope of this standard was limited to the subset of SOLs that are IROLs. The SDT recognizes that exceeding **any** SOL is unacceptable, but adding requirements to this standard that address exceeding SOLs is outside the scope of the associated SAR. The SDT is drafting another SAR to address monitoring and operating within SOLs.

Cinergy Corporation CIN

Cinergy is concerned that retiring existing policies when this Standard goes into affect may allow certain requirements to "fall through the cracks". Absent clear designation of who this Standard would apply to prior to certification of the Reliability Functions leaves some questions regarding the authority of the control areas. For instance, retiring policy 5C2 suggests a System Operator for a Control Area no longer has the authority, or possibly the requirement to possess the authority, to take actions in the event of an emergency. Does the Standard prevent other operating entities such as transmission or generation operators from taking necessary action if needed to prevent damage to facilities due to communication problems with the Reliability Authority or other factors requiring immediate action?

The scope of this standard was limited to the subset of SOLs that are IROLs. The SDT recognizes that exceeding **any** SOL is unacceptable, but adding requirements to this standard that address exceeding SOLs is outside the scope of the associated SAR. The SDT is drafting another SAR to address monitoring and operating within SOLs.

Policy 5C2 states the following:

> **Requirement 5.C.2 Operator authority and responsibility.** SYSTEM OPERATORS having responsibility for the reliability of the transmission system within a CONTROL AREA, pool, etc. shall be given and shall exercise specific authority to alleviate OPERATING SECURITY LIMIT violations. The authority shall enable the SYSTEM OPERATOR to take timely and appropriate actions including curtailing transmission service or energy schedules, operating equipment (e.g., generators, phase shifters, breakers), shedding load, etc.

One of the challenges currently being addressed by the OLDTF is the lack of a common understanding of what constitutes an OSL. The OLDTF developed a new term, IRL, to replace OSL. IRLs are equivalent to IROLs. Under the Functional Model, only the RA will have responsibility for ensuring operations within IROLs.

This standard doesn't prevent entities from taking actions to control local operating issues.

Pacific Gas & Electric Company PGEU (Electric Generators)

As written, this posted Standard 200 is confusing and could degrade system reliability. The stated goal of operating to avoid instability, uncontrolled separation or cascading is too narrow a focus and not good sound operating practice. In truth, the system should be operated within many limitations, such as equipment thermal ratings, generator capability limits, etc. as well as limits for stable power transfer, uncontrolled separation and cascading.

The scope of this standard was limited to the subset of SOLs that are IROLs. The SDT recognizes that exceeding **any** SOL is unacceptable, but adding requirements to this standard that address exceeding SOLs is outside the scope of the associated SAR. The SDT is drafting another SAR to address monitoring and operating within SOLs.

Midwest Independent Transmission System Operator, Inc.

Minnesota Power MP

As this Standard is intended to do away with much of Policy 2, 4 and 5, there appears to no longer be a requirement for BA-BA (or TO-TO) communication or coordination.

MP concurs with similar comments submitted by the MISO regarding lack of clarity of coordination responsibilities.

The scope of this standard was limited to the subset of SOLs that are IROLs. The SDT recognizes that exceeding **any** SOL is unacceptable, but adding requirements to this standard that address exceeding SOLs is outside the scope of the associated SAR. The SDT is drafting another SAR to address monitoring and operating within SOLs.

There are other standards being developed that address other aspects of Policy 2, 4, and 5. The team that was tasked with identifying the scope of an initial set of standards elected to start with a 'clean slate'. The team did not look at each Operating Policy to determine which sections should be translated into a new standard – rather the team listed all the tasks that need to be accomplished to support reliability, and then tried to organize those tasks into logical groupings. For this reason, most of the new standards are not 'one for one' replacements for existing Operating Policies and Planning Standards.

Transmission Agency of Northern California – TANC

First, the definition of Interconnection Reliability Operating Limit includes the following statement --- "A system operating limit which, if exceeded, could lead to instability, uncontrolled separation, or cascading outages that adversely impact the reliability of the bulk transmission system." This statement seems to imply that it is OK to operate over the established limit if it would not cause cascading, even though it could result in damaging equipment, loss of load, or overloads on another entity's facilities. We believe that implying that limits are only exceeded if the violation could lead to "instability, uncontrolled separation, or cascading outages" will lead to a degradation of system reliability. For example, a system operator may conclude that it is acceptable to violate an operating limit as long as the consequences are not a cascading outage. We do not believe that this philosophy is acceptable, especially in light of what happened back east on August 14, 2003.

The scope of this standard was limited to the subset of SOLs that are IROLs. The SDT recognizes that exceeding **any** SOL is unacceptable, but adding requirements to this standard that address exceeding SOLs is outside the scope of the associated SAR. The SDT is drafting another SAR to address monitoring and operating within SOLs.

California Energy Commission

The definition of Interconnection Reliability Operating Limit includes the following statement --- "A system operating limit which, if exceeded, could lead to instability, uncontrolled separation, or cascading outages that adversely impact the reliability of the bulk transmission system." This seems to imply that it is OK to operate over the established limit if it would not cause cascading, even though it could result in damaging equipment, loss of load, or overloads on another entity's facilities. We believe that implying that limits are only exceeded if the violation could lead to "instability, uncontrolled separation, or cascading outages" will lead to a degradation of system reliability. For example, a system operator may conclude that it is acceptable to violate an operating limit as long as the consequences are not a cascading outage. This philosophy is not acceptable.

The scope of this standard was limited to the subset of SOLs that are IROLs. The SDT recognizes that exceeding **any** SOL is unacceptable, but adding requirements to this standard that address exceeding SOLs is outside the scope of the associated SAR. The SDT is drafting another SAR to address monitoring and operating within SOLs.

United States Bureau of Reclamation

The Bureau of Reclamation is concerned that the proposed standard as written will be difficult to enforce. The standard also seems to imply that operating over limits would be permitted if it did not negatively impact the reliability of the system.

The scope of this standard was limited to the subset of SOLs that are IROLs. The SDT recognizes that exceeding **any** SOL is unacceptable, but adding requirements to this standard that address exceeding SOLs is outside the scope of the associated SAR. The SDT is drafting another SAR to address monitoring and operating within SOLs.

Nebraska Public Power District NPPD

NPPD does not believe that this standard goes far enough to protect the integrity of the bulk electric system. As stated in version 2 of the Functional Model the transmission operator has the responsibility to operate and direct the operations of the transmission system within equipment and facility ratings. This standard does nothing to require the transmission operator to take action to return the transmission system to an analyzed safe condition. This standard is too narrowly focused and does not provide the industry with the protection to eliminate a repeat of the August 14th blackout.

The scope of this standard was limited to the subset of SOLs that are IROLs. The SDT recognizes that exceeding **any** SOL is unacceptable, but adding requirements to this standard that address exceeding SOLs is outside the scope of the associated SAR. The SDT is drafting another SAR to address monitoring and operating within SOLs.

Wisconsin Energy Corporation - PM WEC

The requirements for either RA's or TO's to manage lower level facility operating limits for protecting assets or ensuring reliable operations in local areas have yet to be determined or initiated in the standards process. These "lower level" operating requirements must be defined and implemented concurrent with this standard.

The scope of this standard was limited to the subset of SOLs that are IROLs. The SDT recognizes that exceeding **any** SOL is unacceptable, but adding requirements to this standard that address exceeding SOLs is outside the scope of the associated SAR. The SDT is drafting another SAR to address monitoring and operating within SOLs.

Pacific Gas & Electric PGAE

As written, this posted Standard 200 could degrade system reliability since it only requires that the system be operated to avoid instability, uncontrolled separation or cascading. In truth, the system should also be operated within other limitations, such as equipment thermal ratings, generator capability limits, etc.

The scope of this standard was limited to the subset of SOLs that are IROLs. The SDT recognizes that exceeding **any** SOL is unacceptable, but adding requirements to this standard that address exceeding SOLs is outside the scope of the associated SAR. The SDT is drafting another SAR to address monitoring and operating within SOLs.

ISO New England Inc ISNE

This Standard addresses the necessary conditions of instability, separation and cascading outages. However, it does not cover "less severe" reliability concerns which may include, but are not limited to, thermal overloads in one Control Area being caused by poor dispatch, poor system control, or delayed contingency recovery in another Area. Given that the Balancing Standard attempts only to address issues related to system frequency (i.e. CPS 2, and DCS would no longer exist), these "less severe" reliability problems appear not to be addressed by any other standard currently proposed. There seems to be inadequate coordination among the Standards; we would offer a suggestion that NERC appoint a body to oversee and coordinate the Standards so that important criteria are not missed in the process.

The scope of this standard was limited to the subset of SOLs that are IROLs. The SDT recognizes that exceeding **any** SOL is unacceptable, but adding requirements to this standard that address exceeding SOLs is outside the scope of the associated SAR. The SDT is drafting another SAR to address monitoring and operating within SOLs.

Public Service Electric and Gas Company

The present language of the Standard proposed for Ballot must be modifed to include the following issues
There must be a provision clearly stating that the Reliability Authorities have authority over all entities that operate within the RA area of responsibility.

There is a requirement in the RA Certification Standard that addresses this. That standard requires the RA to have a written agreement with all of the entities that report to the RA as well as with adjacent RAs that defines the authority of the RA.

PSEG Energy Resources & Trade LLC PS

PSEG Power LLC

There must be an express provision stating that Reliability Authorities have authority over all entities with facilities or operating within the RA's footprint. (Section 204)

There is a requirement in the RA Certification Standard that addresses this. That standard requires the RA to have a written agreement with all of the entities that report to the RA as well as with adjacent RAs that defines the authority of the RA.

- ***Limits Impossible to Define***

Manitoba Hydro Electric Board MHEB (Electricity Brokers, Aggregators, and Marketers)

Manitoba Hydro MHEB (LSEs)

Manitoba Hydro (Transmission Owners)

We find it very difficult to envision the sort of limit that might be an IROL given the differences between this standard and standard 600. We challenge the standard development team to identify the IROLs that were violated in the August 14, 2003 disturbance. Since this standard requires the IROLs to be identified before, not after, the fact we don't believe that any such limits could have been defined for the system that collapsed, except in the final few minutes.

The scope of this standard was limited to the subset of SOLs that are IROLs. The SDT recognizes that exceeding **any** SOL is unacceptable, but adding requirements to this standard that address exceeding SOLs is outside the scope of the associated SAR. The SDT is drafting another SAR to address monitoring and operating within SOLs.

- ***Suggestions About Format of Standard, Typographical Errors***

Manitoba Hydro Electric Board MHEB (Electricity Brokers, Aggregators, and Marketers)

Manitoba Hydro MHEB (LSEs)

The individual items in Standards 200 should be presented by order of importance. Therefore the items should be renumbered in the following way:
-Standard 207 should become 204 as per bullet immediately above this one.

-Standard 204 “Actions” should be renumbered as 205. -Standard 208 which is linked with “Actions”, but from the perspective of acting on the directives of the RA, should become 206.
-Standard 205 should be renumbered as 207.
-Standard 206 should be renumbered to 208.

The standards will all be entered into a relational database where they can be retrieved by users. When this occurs, the order of the requirements will have little meaning, since most users are expected to retrieve only those requirements that are relevant to them. For example, an entity performing the TOP Function is expected to request just those requirements that are relevant to the TOP.

Manitoba Hydro Electric Board MHEB (Electricity Brokers, Aggregators, and Marketers)

Manitoba Hydro MHEB (LSEs)

Manitoba Hydro (Transmission Owners)

The need for the development of mitigation / corrective actions to be developed, identified and documented for each system condition and any possible violation is very important and this standard does not provide sufficient emphasis on this issue. The standard dealing with this requirement is 207, but we believe it should be better emphasized by placing it immediately after “Analysis and Assessments”.

The range of conditions that may occur on any given day is limitless. It isn’t practical to require that there be detailed plans for every possibility, just plans for those scenarios relative to IROLs that are most probable. There is another standard, “Coordinate Operations” that requires the RA to have a more detailed set of documents to address a wider range of specific operating scenarios. This standard’s focus is limited to IROLs.

National Grid USA

New Brunswick Power Corporation NBPC

New York Power Authority NYPA

Niagara Mohawk NMPC

New York Power Authority MED

Northeast Utilities NU

Nova Scotia Power NSPI

Ontario - Independent Electricity Market Operator IMO

ISO New England Inc ISNE

There is also an inconsistency throughout the Standard. It is titled differently in different places. The document title is “Operate Within Interconnection Reliability Limits” which is correct, however, all the headers within the document appear as “…Interconnected….” The NERC website incorrectly lists the title using the word Interconnected as well.

The titles have been revised so they are consistent.

Entergy EES (Transmission Owners)

Last, the title of the draft standard is “Operate Within Interconnected Reliability Operating Limits” Standard. The title should be “Interconnection”, not “Interconnected”.

The titles have been revised so they are consistent.

- ***Comments about Sanctions***

Mirant Americas Energy Marketing LP MAEM

Concerned with financial sanctions being included at this point. How can this be enforced? My understanding is that not many entities have signed NERC's Reliability Agreement (Agreement for Regional Compliance and Enforcement Programs), enabling the RRCs to enforce compliance programs.

These standards are being written with the assumption that there will be legislation giving NERC the authority to levy financial sanctions. This concept has been adopted by the NERC BOT and is outside the scope of the SDT.

Hydro One Networks Inc (LSEs)

Monetary Sanctions Matrix: Hydro One Networks does not support the inclusion of monetary sanctions in NERC Standards.

These standards are being written with the assumption that there will be legislation giving NERC the authority to levy financial sanctions. This concept has been adopted by the NERC BOT and is outside the scope of the SDT.

New York State Reliability Council
LIPA LIPA (Transmission Owners)

The New York State Reliability Council is opposed to monetary sanctions
The New York State Reliability Council (NYSRC) is opposed to monetary sanctions as the only option for dealing with noncompliance as applied in this and other proposed NERC standards. Unfortunately, direct monetary sanctions invite “gaming the system”, and encourage “business” decisions based on potential profits or savings versus potential penalties. Instead of monetary sanctions, the NYSRC prefers that NERC have authority to issue letters of increasing degrees of severity to communicate non-compliance of standards. The use by the NYSRC and NPCC of letters to regulatory agencies for non-compliance has demonstrated that they are a very effective tool for ensuring adherence to standards; such letters establish the basis for liability in the event of a subsequent criteria violation; and in the case of market participant noncompliance, threaten the violator’s ability to continue to do business with or through an ISO or RTO. Moreover, letters that communicate noncompliance best allow focus on the “root cause” of a violation, as well as its reliability impact. Therefore, the NYSRC strongly recommends removal of monetary sanction matrices from this standard as well as future NERC standards, and consider instead the use of letters such as those presently applied by the NYSRC and NPCC.

These standards are being written with the assumption that there will be legislation giving NERC the authority to levy financial sanctions. This concept has been adopted by the NERC BOT and is outside the scope of the SDT. Further, monetary sanctions are in place in the WECC region and are helping motivate proper performance.

Note that in the Sanctions Table, monetary sanctions are not used as a ‘first response’ for anything but the most severe violations. In most cases, an entity that is not in compliance is sent a letter rather than a fine. In this standard, fines are relatively small – in most cases, the SDT recommended fines that start at a flat $1,000 and progress if the performance continues to be unacceptable. The only requirement with a fine that is potentially large, is the requirement for operating within IROLs. If an IROL is exceeded for a time greater than its T_v, then the fine can be quite large, even on the first offense. This is designed to provide motivation to never allow operations to become so out of control that an IROL is exceeded for so long a time that the result could be instability, a cascading outage or uncontrolled separation from the interconnection. For this violation, the SDT recommended a dollar per megawatt sanction. Several balloters recommended improvements to the sanction drafted by the SDT, and the sanction has been revised to ensure that it provides a sanction proportional to the risk placed on the interconnection.

In this standard, fines are used when there is a pattern or repetitive poor performance or for extremely severe instances of violating a critical reliability requirement., such as exceeding an IROL for time greater than T_v.

ISO New England Inc ISNE

The Monetary Sanction Matrix - There is an issue with the inclusion of this monetary sanction matrix and what its implications are. ISO-NE, as well as NPCC, has expressed concern over its inclusion and maintains that the use of market mechanisms where possible, as well as, letters of increasing degrees of severity and notifications to regulatory agencies are more effective in ensuring compliance. Failure of NERC to gain authority through reliability legislation could result in NERC pursuing actions to implement "Plan B," a "voluntary" approach affording NERC the authority to perform these types of monetary sanctions. ISO-NE has indicated that any posted Standard, with the included matrix, will not be supported by ISO-NE. There are, however, proceedings at NERC by the Compliance Certification Committee (CCC) to address alternative sanction proposals and ISO-NE will continue to work to oppose monetary sanctions.

These standards are being written with the assumption that there will be legislation giving NERC the authority to levy financial sanctions. This concept has been adopted by the NERC BOT and is outside the scope of the SDT. Further, monetary sanctions are in place in the WECC region and are helping motivate proper performance.

United Illuminating UICO

The Monetary Sanction Matrix - There is an issue with the inclusion of this monetary sanction matrix and what its implications are. The NPCC CMAS has expressed concern over its inclusion and maintains that the use of market mechanisms where possible, as well as, letters of increasing degrees of severity and notifications to regulatory agencies are more effective in ensuring compliance. UI agrees with this position.

These standards are being written with the assumption that there will be legislation giving NERC the authority to levy financial sanctions. This concept has been adopted by the NERC BOT and is outside the scope of the SDT. Further, monetary sanctions are in place in the WECC region and are helping motivate proper performance.

NPCC
New York Power Authority MED
Northeast Utilities NU
LIPA LIPA (Transmission Owners)

NPCC does not support the inclusion of a monetary sanction matrix. NPCC maintains that the use of market mechanisms where possible, as well as, letters of increasing degrees of severity and notifications to regulatory agencies are more effective in ensuring compliance.

These standards are being written with the assumption that there will be legislation giving NERC the authority to levy financial sanctions. This concept has been adopted by the NERC BOT and is outside the scope of the SDT. Further, monetary sanctions are in place in the WECC region and are helping motivate proper performance.

National Grid USA

New Brunswick Power Corporation NBPC

New York Power Authority NYPA

Niagara Mohawk NMPC

New York Power Authority MED

Northeast Utilities NU

Nova Scotia Power NSPI

Ontario - Independent Electricity Market Operator IMO

The Monetary Sanction Matrix - There is an issue with the inclusion of this monetary sanction matrix and what its implications are. The NPCC CMAS has expressed concern over its inclusion and maintains that the use of market mechanisms where possible, as well as, letters of increasing degrees of severity and notifications to regulatory agencies are more effective in ensuring compliance. Failure of NERC to gain authority through reliability legislation could result in NERC pursuing actions to implement “Plan B,” a “voluntary” approach affording NERC the authority to perform these types of monetary sanctions. CMAS has indicated that any posted Standard, with the included matrix, should not be supported by NPCC. There are, however, proceedings at NERC by the Compliance Certification Committee (CCC) to address alternative sanction proposals and NPCC will continue to work to oppose monetary sanctions.

These standards are being written with the assumption that there will be legislation giving NERC the authority to levy financial sanctions. This concept has been adopted by the NERC BOT and is outside the scope of the SDT. Further, monetary sanctions are in place in the WECC region and are helping motivate proper performance.

Gainsville Regional Utilities GVL (LSEs)

City of Tallahassee TAL (Transmission Owners)

Sanctions – If the performance reset period is 12 months, then the financial sanctions could be minimal. Was that the intent? The identification of IROLS is critical to reliability.

The performance reset period was 12 months without a violation. The way this performance reset period works, performance is measured over the course of a 12 month period of time. If there is any violation during this time, then the performance reset period would not reset and successive violations would result in increasingly more severe sanctions.

Note that in most cases, the financial sanctions in this standard are only $1,000 or $2,000. Most of the requirements in this standard are related to ‘background’ documents or processes that are needed to support operating within IROLs. These items are very important, but don’t have the same direct link to reliability as operating outside an IROL. The only violation in this standard that could have a substantial monetary fine is operating outside of an IROL for a time greater than T_v.

- ***Comments Submitted with Postings Need More Attention***

Calpine Power Management LP

We concur with the issues raised by the Southwest Power Pool as to the readiness of the Standard to be voted on.

The SPP did not submit comments as part of a ballot for this standard. The SDT reviewed again the comments submitted by SPP during the last posting of this draft standard. Following are all of the comments submitted during that posting, and the responses provided to SPP's comments and all comments were addressed by the SDT.

> It is very cumbersome and can often times be very confusing when two entities are given responsibility for the same task. The requirements outlined in 1.1, 1.2 and 1.1.2 call for both the reliability authority and the planning authority to identify the facilities that have IROLs and also to identify the IROL. We suggest that the reliability authority should be ultimately responsible for identifying and quantifying the IROLs since these are operating limits. However, the reliability authority should thoroughly coordinate this effort with the planning authority. Wording such as "The reliability authority shall coordinate with the planning authority to identify…" would be better. Following this line of thought with the measures in 2.1, 2.1.1 and 2.2, wording should be changed to reflect the reliability authority's ultimate responsibility. "The reliability authority entity shall establish…" makes a better fit.
>
> Several commenters indicated that the RA should be the only function responsible for this requirement, and that change was made to the standard. It is still unclear as to what duties, if any, will be assigned to the Planning Authority, and the SDT elected to omit specific references to the Planning Authority in this standard.
>
> The performance reset period should be changed to 12 months rather than one calendar year.
>
> There were several commenters who suggested changes to the reset period, and the standard was revised so that all requirements in this standard have the following language: "12 months from the last violation" This change supports your recommendation.
>
> The SDT needs to revisit the levels of non-compliance associated with this standard. If compliance is truly a black/white issue with no shades of gray as the proposed levels indicate, why not have just a level one with no financial penalty? The proposed non-compliance level implies that it may be more important to have a list of IROLs rather than a correct list of IROLs. Also, if no IROLs exist, there will be no list which would cause the reliability authority to be in non-compliant. There needs to be consistency throughout all the standards on documentation-type non-compliance.
>
> Several commenters indicated a need to add more levels of non-compliance, and to address 'partial credit' for incomplete lists. Consequently, the standard was modified to require that the lists be updated and to require that the RA have evidence that the lists were updated – and a level three non-compliance was added to give partial credit to RAs who have lists but haven't updated them. This may be equivalent to having an 'incomplete' list. With respect to the appropriateness of levels of non-compliance for documentation - the SDT is only working on this standard, and doesn't have the authority to control what is included in other standards.
>
> Combine 4.3 and 4.3.1 into a revised 4.3 as follows:
>
> "The reliability authority shall have displays with real-time data associated with interconnection reliability operating limits."
>
> References to displays were dropped from this standard since, under some conditions, the RA may not have displays available. The intent is for the RA to demonstrate that it is performing monitoring; therefore the revised wording for 4.3 meets this requirement. In

addition, the RA must demonstrate that it has tools needed for monitoring as part of the RA Certification.

The performance reset period should be changed to 12 months rather than one calendar year.

There were several commenters who suggested changes to the reset period, and the standard was revised so that all requirements in this standard have the following language: "12 months from the last violation"   This change supports your recommendation.

Again the issue of degrees of non-compliance surfaces. Are there shades of gray with non-compliance for this standard or is it strictly a black and white issue? Why jump directly to level four non-compliance? Is progressive non-compliance not an option? For example, if a reliability authority had identified 25 IROLs, he is level four non-compliant if only one of the IROLs is not available for real-time use. Shouldn't there be allowances for such situations? Also, perhaps a letter that lists critical displays and identifies discrepancies would be more beneficial to maintaining interconnection reliability than a monetary penalty.

100 of the 132 commenters were in favor of the proposed levels of non-compliance.

The proposed measures may be too weak. For example, it appears that a reliability authority could satisfy the operational planning analysis by evaluating an invalid case for a given day. While it meats the letter of the measure, it doesn't meet the intent of the measure. Also, does 2.1.2 apply to IROLs that are associated with stability limits? If so, this measure would require a reliability authority to run real-time stability analyses every 30 minutes.

The term, 'analysis' is not synonymous with 'study.' IROLs may be associated with stability limits, but this does not mean that a stability study needs to be conducted every 30 minutes. The standard does not specify what tools must be used to conduct the analysis or the assessment – this is left up to the RA.

Again the issue of degrees of non-compliance surfaces. Are there shades of gray with non-compliance for this standard or is it strictly a black and white issue? Why jump directly to level four non-compliance? Is progressive non-compliance not an option? Is missing an operational planning assessment one day in a month as detrimental as missing it 10-15 days per month? Similarly, is missing one real-time assessment as bad for reliability as missing these assessments for hours, on a regular basis?

The levels of non-compliance were adjusted to reflect changes to the compliance monitoring process. Under the revised standard, a level three non-compliance was added.

The performance reset period should be changed to 12 months rather than one calendar year.

There were several commenters who suggested changes to the reset period, and the standard was revised so that all requirements in this standard have the following language: "12 months from the last violation"

Non-compliance items should match the standard's definitions. Section 5.1 should be referred to as a Documentable Interconnection Reliability Operating Limit Violation. Section 5.2 should be referred to as an Interconnection Reliability Operating Limit Violation or a Reportable Interconnection Operating Limit Violation, whichever is correct (see response to Question 1).

The terms, Documentable IROL and Reportable IROL were not used in the last draft of this standard, and several commenters indicated it should be dropped. The terminology used in the levels of non-compliance matches the terminology used in the standard, so this suggestion was not adopted.

Requirements 1.1, 1.2 and 1.3 are too open-ended on the part of the reliability authority. Justification should be required for all requested data to prevent unreasonable and burdensome requests on the part of the reliability authority. The data requested and the timing of the delivery of the data should be mutually agreeable to the reliability authority and the responding entity.

Adding a justification requirement seems to be overly burdensome. If an entity wants to challenge the need for data and can't resolve the issue with its RA, then that entity can use the dispute resolution process.

The SDT should define a minimum, default set of data, such as that spelled out in Appendix 4B, and provide that as a guide for what type of data may be requested.

The industry as a whole is not in favor of a 'minimum' set of data. Any RA is free to copy the contents of Appendix 4B and include this as part of its data specification. Appendix 4B, by itself, would not meet all of the measures in this requirement.

Requirement 1.3 appears to be repeated again as a measure in Measure 2.3. Shouldn't Requirement 1.3 be moved to Standard 206 since it deals with provision of the data? In fact, there is a great deal of material in 205 that is related data provision. Shouldn't all of this be moved to 206? Perhaps additional clarification between 205 and 206 is all that is needed.

There are many different ways of sorting the various requirements in this standard. Industry comments on the first version of the standard indicated a preference for putting related requirements together. If requirement 1.3 were moved to 206, this might increase confusion. In requirement 206, one RA has to provide data to another RA, and it may be confusing as to which RA had to notify the Compliance Monitor when data wasn't provided as specified.

The performance reset period should be changed to 12 months rather than one calendar year.

There were several commenters who suggested changes to the reset period, and the standard was revised so that all requirements in this standard have the following language: "12 months from the last violation" This change supports your recommendation.

The cover letter requirement in 4.3.1 is confusing and needs clarification. While such a letter can provide evidence that data has been sent, such a requirement could also prove to be excessive and impractical. Infrequent data transmittals such as impedance changes, ratings, etc, could easily be transmitted under cover letter. However, does this requirement also apply to each bit of real-time data transmitted via ICCP?

Several commenters agreed with your comment about 4.3.1. The standard was revised as follows: Evidence indicating data was sent to the reliability authority or evidence that the entity responsible committed to providing the data on the specification. ~~Copies of transmittal cover letters indicating data was sent to the reliability authority.~~

Only one data point out of potentially thousands of points could cause non-compliance as specified in Section 5. This implies that nothing less than 100% of the data, 100% of the time is sufficient. Is this the intent of the SDT? Is a transducer failure in a remote substation as damaging to reliability of the interconnection as the loss of an entire ICCP link between a responding entity and its reliability authority? Is a failure for one scan cycle as critical as that point not being available for days or weeks? It would appear that non-compliance associated with this standard needs revisiting.

The data specification issued by the RA under requirement 205 must identify how real time data will be supplied when there are telecommunication failures. As long as the data is supplied as specified, there is no sanction. (205.2.1.2 Specification shall address the data provision process to use when automated real-time system operating data is unavailable.)

There appears to be inconsistency between non-compliance in 205 and 206. If a reliability authority makes an unreasonable data request in 205 and doesn't get the requested data within the specified timeframe, then the reliability authority is only penalized at a level one. But if a responding entity loses one data point for one four-second data scan, that responding entity is blasted with a level four penalty. There does not appear to be equity here.

If an entity feels that the data specified by the RA is unreasonable, then that entity can try to resolve the issue with its RA or through the dispute resolution process. Both requirements 205 and 206 were modified to add a provision that if the RA is able to resolve the issue of not receiving the data it needs, then the RA does not need to notify its compliance monitor. There is only a level four non-compliance for requirement 206 if the entity does not provide the data as specified AND the entity is unable to resolve the discrepancy with its RA.

Generator operators need to be added to the entities listed in Requirement 1.1.

The Functional Model provides a 'chain of command' type of functional relationship that has been supported in the development of this standard. This 'chain of command' type of structure doesn't support having the RA direct all entites performing all functions, rather the Functional Model has the RA giving directives to a subset of functions, and this subset of functions then passes on instructions to other functions. The generator operator was not added to the list of functions that must comply with this standard because under the Functional Model, the generator operator takes direction from the balancing authority, not the reliability authority.

Requirement 1.2 is repeated again in Measure 2.1.

Some commenters indicated a preference for including a measure that specifically addresses each of the requirements. The measures are intended to identify the elements that the compliance monitor will look at to determine if the desired performance has been achieved – there is nothing wrong in including the same language in both the requirement and the measures.

The levels of non-compliance need to be reviewed to ensure that they accurately reflect how well the directives were followed. Timing of actions taken with regards to when the directives were issued should also be considered.

In many instances, how well a RA's directives are followed is a function of the communication skills of the system operator providing direction. If the RA's directives include timing, then it is fair to include a consideration of timing when assessing non-compliance. If the RA's directives do not include a timing requirement, then this would be impossible to measure objectively.

The SDT should utilize the NERC functional model and thoroughly review and correct all definitions associated with this standard. Some definitions included in this standard are not needed and others don't appear to belong in the standard. Others are simply the wrong definition. Noting the comment box on page 3 of the standard, we wonder why a definitions section was even included in the standard.

Here are some specific problem definitions:

Real-time Monitoring and the use of vision and hearing to define this term.

The term, 'real-time monitoring' was revised by replacing the phrase, "To use vision and hearing to scan. . ." with the phase, "The act of scanning . . . "

Real-time – Shouldn't historical time also be included?

It is not clear why historical time should be included in a definition of real time.

Self-certification – Why is this term included in this standard? It probably belongs in the Compliance Enforcement Document. The second sentence doesn't appear to be a part of the definition.

Self-certification is used in this standard and hasn't been previously defined in the glossary of terms associated with Reliability Standards. Several entities requested that the term be defined during the last posting of this standard.

Transmission Operator has the wrong definition. The definition given is the definition for Transmission Service Provider.

The definition for Transmission Operator was transposed with the definition for Transmission Service Provider.

Documentable Interconnection Reliability Operating Limit Violation and Interconnection Reliability Operating Limit Event have the exact same definition.

Reportable Interconnection Reliability Operating Limit Violation and Interconnection Reliability Operating Limit Violation are basically the same definition.

Reportable Interconnection Reliability Operating Limit Violation and Interconnection Reliability Operating Limit Violation are not used in the standard and have been dropped from the list of defined terms.

Tv should be listed as T_v.

The missing subscript "Tv" rather than "T_v", is a typo and has been corrected.

This standard does not require the reliability authority to notify those entities not providing data to remind those entities that they should be providing data. The reliability authority should be trying to obtain the missing data and working to resolve differences that prevent delivery of the data. If the reliability authority and the responding entity cannot reach agreement on data delivery, then the reliability authority should notify the compliance monitor.

Agreed – this standard does not require the RA to provide a reminder to those entities that need to provide data. This does not preclude the RA from providing such a reminder.

The performance reset period of one calendar year in 201, 202, 204 and 205 should be changed to 12 months. 206, 270 and 208 should remain 12 months.

There were several commenters who suggested changes to the reset period, and the standard was revised so that all requirements in this standard have the following language: "12 months from the last violation" This change supports your recommendation.

Areas where non-compliance is the result of a lack of proper documentation should be consistent throughout each individual standard and across all standards, especially between this standard and Standard 600, Determine Facility Ratings, System Operating Limits and Transfer Capabilities.

Changes in standards are driven by the comments submitted by the industry. A lack of proper documentation in one standard is not necessarily the same as in another standard.

Westar Energy Generation & Marketing WRGS (Generators)

Does not meet criteria suggested by SWPP ORWG.

The SWPP did not submit comments as part of a ballot for this standard.

Westar Energy Generation & Marketing WRGS (Brokers)

Based on SPP reliability working group recommendations

The SWPP did not submit comments as part of a ballot for this standard.

- ***Transmission Owners Fiduciary Responsibilities And Liability Concerns***

Carolina Power & Light Company CPL (Transmission Owners)
Carolina Power & Light Company CPL (LSEs)
Carolina Power & Light Company CPL (Generators)

Overall, this standard ignores Transmission Owners' fiduciary responsibilities and liability concerns, thereby ignoring coordination of responsibilities among the industry entities. Transmission Owners must be an integral part of the development of limits, operations to stay within those limits, and monitoring of facilities. Leaving out the concerns of the Transmission Owners would ignore their fiduciary responsibilities and liability concerns. Such a lack of coordination in the planning phase would result in confusion in the operating not unlike that exhibited in the northeast blackout.

The Transmission Owner is responsible for establishing facility ratings for its equipment. The Transmission Owner's facility ratings must be respected by the entities that develop associated system operating limits and Interconnection Reliability Operating Limits. The new standards being developed by NERC are being developed in support of the terminology and concepts in the Functional Model. The Functional Model assigns the Reliability Authority the responsibility for identifying IROLs. To clarify that the Transmission Owner's facility ratings must be respected, this standard has been revised to include a statement indicating that the IROLs are developed from SOLs that are developed according to the Determine Facility Ratings, System Operating Limits and Transfer Capabilities Standard.

Entergy EES (Transmission Owners)

The drafting team has completely ignored the fiduciary responsibilities and liability concerns of Transmission Owner. Transmission Owners must be an integral part of the development of the limits, operations to keep the system within those limits and monitoring of the facilities. This standard should be revised to reflect those fiduciary responsibilities and liability concerns.

The Transmission Owner is responsible for establishing facility ratings for its equipment. The Transmission Owner's facility ratings must be respected by the entities that develop associated system operating limits and Interconnection Reliability Operating Limits. The new standards being developed by NERC are being developed in support of the terminology and concepts in the Functional Model. The Functional Model assigns the Reliability Authority the responsibility for identifying IROLs. To clarify that the Transmission Owner's facility ratings must be respected, this standard has been revised to include a statement indicating that the IROLs are developed from SOLs that are developed according to the Determine Facility Ratings, System Operating Limits and Transfer Capabilities Standard.

Southern Company Services SOCO (Generators)
Southern Company Services SOCO (Transmission Owners)
Georgia Power Company (LSEs)

Overall, this standard ignores Good Utility Practice and the Transmission Owners fiduciary responsibilities and liability concerns. It thereby ignores the coordination of responsibilities

among the industry entities, and the standard should have these two definitions modified.
The Transmission Owner is responsible for establishing facility ratings for its equipment. The Transmission Owner's facility ratings must be respected by the entities that develop associated system operating limits and Interconnection Reliability Operating Limits. The new standards being developed by NERC are being developed in support of the terminology and concepts in the Functional Model. The Functional Model assigns the Reliability Authority the responsibility for identifying IROLs. To clarify that the Transmission Owner's facility ratings must be respected, this standard has been revised to include a statement indicating that the IROLs are developed from SOLs that are developed according to the Determine Facility Ratings, System Operating Limits and Transfer Capabilities Standard.

FERC's definition of Good Utility Practice is repeated here:

> Any of the practices, methods, and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods, and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety, and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act, to the exclusion of all others, but rather to be a range of acceptable practices, methods, or acts generally accepted in the region. Good Utility Practice shall include, but not be limited to, compliance with Applicable Laws and Regulations, Applicable Standards, the National Electric Safety Code, and the National Electrical Code, as they may be amended from time to time, including the criteria, rules and standards of any successor organizations.

- ***IROL Violation Report Form***
  Southern Company Services SOCO (Generators)

Southern Company Services SOCO (Transmission Owners)

Carolina Power & Light Company CPL (Transmission Owners)

Carolina Power & Light Company CPL (LSEs)

Carolina Power & Light Company CPL (Generators)

Georgia Power Company (LSEs)

The **IROL violation Report Form** does not appear to capture some pretty important data, such as affected parties and narrative on the event. Also, this is the first opportunity for "the world" to review the actual form. It was only referenced in previous postings.

Some of the data that is contained within the existing report filed as part of Policy 2 is not used in the IROL Violation Report. There are some elements in the existing report that are used to analyze the reason for operating security limit violations. In the set of new Reliability Standards, the analysis of major system events is addressed in the "Monitor and Analyze Disturbances, Events and Conditions Standard." The IROL Violation Report is a compliance form used to collect immediately available data that indicates the severity of the IROL violation.

- ***Tools, training, etc.***

National Grid USA

New Brunswick Power Corporation NBPC

New York Power Authority NYPA

Niagara Mohawk NMPC

New York Power Authority MED

Northeast Utilities NU

Nova Scotia Power NSPI

Ontario - Independent Electricity Market Operator IMO

Hydro One Networks Inc (LSEs)

ISO New England Inc ISNE

The System Operators must have the tools, training and information to deal with unforeseen circumstances and make the proper decisions to secure the system in an expeditious and orderly manner following a contingency or other event.
There is sufficient time provided in the implementation schedule for each entity to provide its system operators with the tools and training needed to comply with the standard.

The scope of this standard must be within the associated SAR which did not include tools or training of system operators. Both tools and training are addressed in the certification standards for the RA, Balancing Authority, and TOP.

- ***Comments about Adherence to Standards Development Process***

Southern Company Services SOCO (Generators)
Southern Company Services SOCO (Transmission Owners)
Georgia Power Company (LSEs)

It appears that there were some standard responses that the SDT developed and used for most of the comments. It did not appear that all comments were given their due consideration.

The SDT has considered every comment submitted with each posting of this standard. Many of the industry comments submitted with ballots were comments that had not been submitted on any of the postings of the draft standard. Many of the comments that the SDT has been unable to resolve are unrelated to this standard – these are comments that relate to elements within the compliance program, an understanding of the standards development process, and an understanding of the functional model.

Bonneville Power Administration - Power Business BPAP

Procedurally, it seems that for the number of changes that were made to the standard after the last round of comments, an additional round of comment would have been more appropriate than taking this dramatically changed draft to a final vote.

The first ballot of the Standards Process is equivalent to the 'Call for the Question' in Robert's Rules of Order. The purpose of the "Call for the Question" is to determine if the industry is ready to ballot a standard. From the results of the ballot, it is clear that the industry wants changes to their understanding of the standards process, to the compliance program, to the functional model, and to this standard.

Tennessee Valley Authority - Transmission/Power Supply (Transmission Owners)

The resolution of industry concerns as expressed through the comment period is required for this standard to be acceptable. Our region as well as other federal entities have expressed somilar concerns.

The SDT has considered every comment submitted with each posting of this standard. Many of the industry comments submitted with ballots were comments that had not been submitted on any of the postings of the draft standard. Many of the comments that the SDT has been unable to resolve are unrelated to this standard – these are comments that relate to elements within the compliance program, an understanding of the standards development process, and an understanding of the functional model.

Bonneville Power Administration Transmission BPAT

There should be a Technical Reference, either attached to the Standard or as an appendix to the Standard, with much of the information that is in the Question and Answer document, including the IROL Violation Report form.

The SDT may develop or recommend the development of a Technical Reference to support this standard, however the SDT was unable to develop a Technical Reference in a timeframe that would coincide with the development of this standard. (SDTs are not precluded from drafting informal documents such as 'FAQs'.) According to the Reliability Standards Process Manual, a Technical Reference must be approved by the Standing Committees. Until the standard is finalized, it isn't practical to finalize a Technical Reference and submit it to the Standing Committees for approval.

- ***Other Miscellaneous Comments***

Cinergy Corporation CIN

In light of the events affecting the Eastern Interconnection on August 14, 2003 resulting in the blackout of millions of customers in the United States and Canada, Cinergy feels that the standard may not adequately address recommendations yet to come from the Task Force investigating the event. Cinergy believes that the approval of this standard should wait until recommendations from the Task Force on preventing future blackouts are released.

The SDT has monitored the blackout investigation and interim reports and has not see anything in the blackout findings that indicates a need to change this standard. If the blackout recommendations do indicate a need for additional requirements that are closely related to the topics addressed in this standard, then additional SARs may be developed to address those requirements. The Standards Development Process mandates that this SDT develop a standard that is within the scope of the already approved SAR for this standard. Adding requirements that are outside the scope of the approved SAR is not acceptable within the Standards Development Process.

Con Edison Company of New York CEPD
Con Edison Company of New York CEPD
Consolidated Edison Co. of New York NYCE
New York State Reliability Council
LIPA LIPA (Transmission Owners)

It should be stated in Standard 200 that more stringent criteria than specified in the Standard may be adopted by a Region or sub-region, even if not specifically identified in the Regional Differences section.

According to the Reliability Standards Process Manual (pages 20-21), if a Region wants specific language added to a NERC Reliability Standard to reflect a requirement that is only applicable to a Region, then the Region must request a Regional Difference. There weren't any requests for Regional Differences in this Standard. Regions are not precluded from adopting and enforcing more stringent criteria than specified in a NERC Reliability Standard.

MAIN

This standard appropriately does not just use the limits described in "(Draft) Standard 600 - Determine Facility Ratings, System Operating Limits and Transfer Capabilities" since the IROLs are to address circumstances that lead to instability, uncontrolled separation or cascading outages that adversely impact the reliability of the bulk transmission system. This distinction should be preserved and made more clear.

The first requirement in this standard (201 – IROL Identification) has been revised to include a specific link to Standard 600.

Wisconsin Energy Corporation - PM WEC

We agree with requirements 202, 203, 205, 206.