Drafting Team Responses to Industry Comments Regarding the First Posted Version of the Determine Facility Ratings, System Operating Limits, and Transfer Capabilities Standard
December 1, 2003

1. Have the roles and responsibilities of transmission operators vs. reliability authorities in determining system operating limits been properly characterized in this standard?

NERC Transmission Subcommittee Robert Reed – PJM Daniel Cooper – Michigan Public Power Agency Ken Donohoo – ERCOT Michael Gildea – Duke-Energy, North America Francis Halpin – BPA Tom Mallinger – MISO Darrick Moe – WAPA Scott Moore – AEP Bill Slater – Florida Power Corp Tom Stuchlik – Western Resources Joseph Styslinger – Southern Co David Thorne – DH Thorne Consultants Robert Waldele – NYISO Roman Carter – Southern Co John Ahr – Allegheny Power Susan Morris – SERC Ed Pfeiffer – Ameren Ray Palmieri – ECAR	Yes.
Mark Heimbach – PPL Generation, Segment 5	Yes.
Roman Carter (& 9 other employees) - Southern Company Generation and Marketing, Segments 5,6 Terry Crawley & Roger Green – SOCO Generation, Segment 5	No. It is recommended that Transmission Operators have the ultimate responsibility to establish system operating limits within their local area. The RA has the responsibility to apply these limits under its Reliability area to ensure the security of the system. Response: The suggested approach would not work in all areas (for example ERCOT), due to the role of the transmission operator and the tools and data available to them. However, the standard acknowledges that RA's and TOPS both have a role in the determination of operating limits, much as the Functional Model does. It is assumed that further revisions of the Functional Model will add greater clarity in this area.
R T Sikes (& 4 other employees) – CenterPoint Energy Real Time Operations	No. This should be a coordinated effort between the Authorities and the Transmission Operator. We are not sure this is clear. Response: The standard acknowledges that both Reliability Authorities and Transmission Operators have a role in determining system operating limits. Actual organizational relationships will be established outside this standard, such as RTO relationships, RRO relationships, etc. It is assumed that further revisions of the

	Functional Model will add greater clarity in this area.
Alan Johnson – Mirant Americas Energy Mktg, Segment 6	Yes.
SERC Planning Standards Working Group Clay Young – South Carolina Electric & Gas, Segment 3 Byron Stewart – TVA, S1 David Weekly – Municipal Electric Authority of Georgia – S1 Brian Moss – Duke Power, S1 Darrell Pace – Alabama Electric Cooperative, S1 Bob Jones – SoCo, S1 Kham Vongkhamchanh – Entergy, S1 Pat Huntley – SERC, S2	No. Establishment of the Operating Limits are the joint responsibility of the RA, PA, and the TO in concert. It appears that question 1 is inconsistent with 604.1.1. Response: 604.1.1 requires that RA, PA and TOP establish system operating limits for their areas. The standard acknowledges that the RA, PA and TOP all have a role in the determination of operating limits, much as the Functional Model does. It is assumed that further revisions of the Functional Model will add greater clarity in this area.
SERC Operations Planning Subcommittee Carter Edge – Southeastern Power Administration, S4&S5 William Gaither – South Carolina Public Service Auth, S1 Mike Miller – SoCo, S1 Roger Brand – Municipal Electric Authority of Georgia, S1 Phil Creech – Progress Energy (Carolina), S1 Gene Delk & Al McMeekin – South Carolina Electric and Gas, S1 Greg Ott – Alcoa/Yadkin, S1 Doug Newbauer – Georgia System Operations, S1 Mike Clements & Mark Creech – TVA, S1 Don Reichenbach – Duke Energy, S1 Lynna Estep – SERC, S2	No. Same comments as SERC Planning Standards Working Group listed above.
Robert Grover – PPL, S3	Yes.
John Horakh – MAAC, S2	Yes.
David Thorne – PEPCO, S1	Yes
Todd Lucas & 5 other employees – SoCo Trans Plng, S1 and S3	No. It is not clear that the transmission operator will not have responsibility for establishing system operating limits. The phrase “for the areas for which they are responsible” appears several times. We assume this is a reference to the functional model responsibilities. We believe it would be helpful if these areas of responsibility were re-stated in this standard, making it clear what these areas are for each entity. We believe that there are certain system operating limits that the Transmission Operator will have the ultimate responsibility to establish.

	Response: The suggested approach would not work in all areas (for example ERCOT), due to the role of the transmission operator and the tools and data available to them. However, the standard acknowledges that RA's and TOPS both have a role in the determination of operating limits, much as the Functional Model does. The standard cannot universally define the boundaries for the entities performing the identified functions.
Lee Westbrook – OnCor, S1	Yes. Transmission Operator input is dependent upon its receipt of dependable data and other information from equipment owners, and the responsibility of the Transmission Operator must be limited by the dependability of the information it receives. Response: The standard does require that those needing data must receive it in a reasonable amount of time (as determined by the parties). The standard cannot limit liability based upon accuracy of data, though.
Darrel Richardson – Illinois Power, S1 S2	Yes.
Ed Davis – Entergy, S1	No. We believe the Transmission Owner has the ultimate responsibility to establish equipment operating limits which is a result of its fiduciary responsibility for its owned facilities. The Transmission Owner has ultimate responsibility and liability for owning, maintaining and operating its facilities to protect its stockholders' and lending institutions' investments. The Transmission Owner, then, is ultimately responsible for establishing system operating limits based on thermal ratings. While the Transmission Owner may voluntarily contract to have some other entity (function) perform some of the operations needed to ensure that fiduciary responsibility, it is the Transmission Owner that has ultimate responsibility. Neither NERC standards nor the Functional Model can allocate or transfer that responsibility to the RAs. Under state law, Transmission Owners must typically obtain state regulatory approval to transfer control or operational authority over jurisdictional facilities to third parties. Forcing Transmission Owners to allow a third party, such as the RA, to cede ultimate responsibility for establishing equipment limits could trigger the need for state regulatory approvals. However, the Transmission Owners may voluntarily contract some functional responsibilities to other entities, like the RA, TOP, and TSP, but the ultimate responsibility would still reside with the transmission Owner. System operating limits (and interconnection reliability operating limits) are the lesser of the thermal, stability and voltage limits. The determination of each of these limits resides with different entities (functions). Equipment thermal limits and the thermal-based value of Tv for that equipment are the responsibility of the Transmission Owners. (For instance, a Transmission Owner might have dynamic thermal line ratings on specific transmission lines which are the responsibility of the TO.) Stability limits and associated value of Tv are the responsibility of the RA in the operating horizon and the PA in the planning horizon. Voltage limits are a responsibility shared by all three entities (functions). Therefore, we believe it is incorrect to say that any one entity (function) has ultimate responsibility to establish system operating limits. We also believe it is incorrect to say that any one entity (function) has ultimate responsibility to establish Interconnection Reliability Operating Limits. We suggest the above reasoning be used to revise this standard, the Operate Within IROL standard, and all other standards. Response: The standard recognizes the right of facility owners to determine the appropriate ratings for their facilities. The standard also requires that system operating limits respect the facility ratings. The standard does not require that owners cede their

	right to establish facility ratings to any third party. System operating limit determination requires wider-area information that the facility owner may not have.
MAPP Operations Subcommittee Allan Silk – Manitoba Hydro Paul Brune – NPPD Paul Koskela – Minnesota Power Larry Larson – Otter Tail Darrick Moe – WAPA Dick Pursley – Great River Energy Martin Trence – Xcel Energy Todd Gosnell – Omaha PPD Joseph Knight – MAPPCOR, S2	Yes.
Clay Young and 8 employees – South Carolina Electric & Gas, S1, S3, S5	No. Establishment of the Operating Limits are the joint responsibility of the RA, PA, and the TO in concert. The TO should have ultimate responsibility for facility ratings because they will be required to replace the equipment if it fails due to overload. It appears that question 1 is inconsistent with 604.1.1. Response: The drafting team agrees that facility owners have the ultimate responsibility for rating their facilities and believes the standard is consistent with this comment.
Paul Johnson – AEP, S1,S3,S5, S6	Yes. We would expect that the working relationship between the RA's and the TOPs would be such that the RA would monitor the SOL conditions that would have a 'wide-area' and/or large load interruption implications while the more local issues and conditions would be delegated to the Transmission Operators to monitor. In any case the Reliability Authority has the ultimate responsibility. Response: This comment is consistent with the intent of the standard.
Dilip Mahendra – SMUD, S1	Yes.
James Spearman & Florence Belser – PSC of S. Carolina, S9	Yes.
SPP Operating Reliability WG Gerry Burrows – KCP&L, S1 Bob Cochran – SPS, S1 Peter Kuebeck – OG&E, S1 Scott Moore – AEP, S1 Dan Boezio – AEP, S1 Tom Stuchlik – Westar, S1 Matt Bordelon – CLECO, S1 Mike Crouch – WFEC, S1 Mike Gammon – KCP&L, S1 Kevin Goolsby – SPP, S2 Bo Jones – Westar, S1 Allen Klassen – Westar, S1 Thad Ness – AEP, S1 Harold Wyble – KCP&L, S1	Yes, especially with regards to Standards 603 and 604.

Robert Rhodes – SPP, S2	
John Blazekovich - Exelon, S1,S3,S5,S6	No. We suggest that the words used in the above question be used in the actual standard. The standard states that "the reliability authority, planning authority and transmission operator shall establish system operating limits for the areas they are responsible". This wording does not reflect the statement made in question1 above. The following wording is suggested: "The reliability authority, planning authority, and transmission operator shall establish system operating limits as required for the areas which they are responsible. The planning authority has the ultimate responsibility to establish system operating limits with input from the transmission operator." Response: The standard acknowledges that the RA, PA and TOP all have a role in the determination of operating limits, much as the Functional Model does. It is assumed that further revisions of the Functional Model will add greater clarity in this area.
Raymond Mammarella – PPL, S1	Yes.
Carter Edge – S.E. Power Admin, S4, S5	No. Same comments as SERC Planning Standards Working Group listed above.
Tom Pruitt & 4 other employees – Duke Power, S1 & S5	No. The assumption made by the team is incorrect and does not concur with the standard. The reliability authority (RA) alone does not set all System Operating Limits (SOL's). Establishment of SOL's is the responsibility of the RA, planning authority (PA), and transmission owner (TO) in concert (reference section 604.1.1 of this standard). Response: The standard acknowledges that the RA, PA and TOP all have a role in the determination of operating limits, much as the Functional Model does. It is assumed that further revisions of the Functional Model will add greater clarity in this area.
Alan Boesch – NPPD, S1	Yes.
Tony Jankowski – We Energies, S4	No. Think only one function shall be responsible for ensuring system operating limits are established. Response: The standard attempts to remain as true to the functional model as possible, and responsibility for these activities is assigned to more than one function in the model. It is assumed that further revisions of the Functional Model will add greater clarity in this area.
Don Chandler – CenterPoint, S1	Yes.
Tom Mielnik – MidAmerican, S3	Yes.
Michael Sidiropoulos – Pacificorp, S1	Yes.
Mitchell Needham – TVA, S1 Gary L. Jackson – TVA, S6 Mark Creech - TVA	No. The RA, PA, and TO should jointly establish Operating Limits for their facilities. The statement "that the reliability authority has the ultimate responsibility to establish system operating limits," should be re-written to say "that the reliability authority has the responsibility to establish real-time operating limits". Response: The standard acknowledges that the RA, PA and TOP all have a role in the

	determination of operating limits, much as the Functional Model does. It is assumed that further revisions of the Functional Model will add greater clarity in this area.
Mike Viles & 9 other employees – BPA Transmission, S1	No. If it must be assumed that the reliability authority has the ultimate responsibility to establish system operating limits then the roles and responsibilities have not been properly characterized. The standard states that the operating limits shall be established by the reliability authority, planning authority, and transmission operator but does not state that the reliability authority is ultimately responsible for establishing the system operating limts. Clarity in the roles and responsibilities is preferred over assumptions. Response: The standard acknowledges that the RA, PA and TOP all have a role in the determination of operating limits, much as the Functional Model does. It is assumed that further revisions of the Functional Model will add greater clarity in this area.
Carey Gates – CalISO, S2	No. Section 604 1.1 states that "The reliability authority, planning authority and transmission operator shall establish system operating limits for the areas for which they are responsible". This statement does not establish who has the "ultimate" responsibility for establishing SOLs. Response: The standard acknowledges that the RA, PA and TOP all have a role in the determination of operating limits, much as the Functional Model does. It is assumed that further revisions of the Functional Model will add greater clarity in this area.
Susan Morris – SERC, S2 Bill Reinke – SERC, S2 Sam Stryker – Fayetteville PWS, S3, S4, S5 John Stickley – AECI, S1 Carter Edge – SEPA, S4,S5 John Troha – SERC, S2 Tim Ponseti – TVA, S1 Bill Thompson – Dominion Transmission, S1	No. It appears that question 1 is inconsistent with 604.1.1. However, the Transmission Owner has the ultimate responsibility to establish system operating limits which is a result of its fiduciary responsibility for its owned facilities. The Transmission Owner has ultimate responsibility and liability for owning, maintaining and operating its facilities. The Transmission Owner, then, is ultimately responsible for establishing system operating limits. While the Transmission Owner may voluntarily contract to have some other entity (function) perform some of the operations needed to ensure that fiduciary responsibility, it is the Transmission Owner that has ultimate responsibility. Neither NERC standards nor the Functional Model can allocate or transfer that responsibility to the RAs. Transmission Owners subject to state jurisdiction must typically obtain state regulatory approval to transfer control or operational authority over jurisdictional facilities to third parties. Forcing Transmission Owners to allow a third party, such as the RA, to cede ultimate responsibility for establishing system limits could trigger the need for state regulatory approvals. However, the Transmission Owners may voluntarily contract some functional responsibilities to other entities, like the RA, TOP, and TSP, but the ultimate responsibility would still reside with the Transmission Owner. System operating limits (and interconnection reliability operating limits) are the lesser of the thermal, stability and voltage limits. The determination of each of these limits resides with different entities (functions). Equipment thermal limits and the thermal-based value of Tv for that equipment are the responsibility of the Transmission Owners. (For instance, a Transmission Owner might have dynamic thermal line ratings on specific transmission lines which are the responsibility of the TO.) Stability limits and associated value of Tv are the responsibility of the RA in the short-term horizon and the PA in the long-term horizon. Voltage limits are a responsibility shared by all three entities (functions). Therefore, we believe it is incorrect to say that any one entity (function) has ultimate responsibility to establish system operating limits. We also believe it is incorrect to say that any one entity (function) has ultimate responsibility to establish Interconnection Reliability Operating Limits.

	We suggest the above reasoning be used to revise this standard, the Operate Within IROL standard, and all other standards. Response: The standard recognizes the right of facility owners to determine the appropriate ratings for their facilities. The standard also requires that system operating limits respect the facility ratings. The standard does not require that owners cede their right to establish facility ratings to any third party. System operating limit determination requires wider-area information that the facility owner may not have.
Gerald Rheault – Manitoba Hydro, S1, S3, S5, S6	Yes. The Functional Model assigns responsibility for developing operating limits to the RA therefore this Standard is consistent with the Model and the responsibility has been properly assigned.
Peter Burke – American Transmission Company, S1	Yes. The draft standard mentions generator owners/operators which is not mentioned in this question. Is it the intent of this standard to address ATC calculations? If not, this standard should not include a requirement for Transmission Owners to provide system operating limits to Transmission Service Providers. This standard might be improved by adding the phrase "provide … as needed." This standard also includes a requirement for documentation of margins used in the calculation of system operating limits - isn't that also related to transmission service and potentially not appropriate for this standard? Response: Generator owners/operators do not establish *system* operating limits. For this reason, they were not mentioned in this question. During the development of the SAR associated with this standard, industry consensus did not support the inclusion of ATC in this standard. For this reason, the standard does not address ATC. The intent of the referenced requirement is to ensure that TSPs receive system operating limits so that they can perform their function. "Provide as needed" can be difficult to measure for compliance purposes. The margins referred to in the standard are not related to transmission service (ie, TRM and CBM), but are instead operational reliability margins.
Kirit Shah – Ameren, S1	Yes.
WECC Technical Studies Subcommittee Peter Mackin – Trans Agency of Northern Calif, S1 Chifong Thomas – Pacific G&E, S1 Esteban Martinez – Turlock Irrigation District, S1 Peter Krzykos – Ariz Public Service, S1 Joe Seabrook – Puget Sound, A1 Phil Park – BC Trans Co, S1 C V Chung – Seattle City Light, S9	Yes.
FRCC OC, EC, MIC Linda Campbell – FRCC, S2 Paul Elwing – Lakeland Electric, S3	Yes and No. As stated in our comments on the draft "Operate within limits" standard, we are still confused about what the RA is. It seems like you can have it be different things in different circumstances. If the RA has the role of todays reliability coordinator, we

John Shafer – FP&L, S1 Don McInnis – FP&L S1 Patti Metro – FRCC, S2 Joe Krupar – FMPA, S3 Richard Gilbert – Lakeland Elect S3 Amy Long – Lakeland Elect S1 Roger Westphal – Gainesville Regional Utilities S5 Bob Remley – Clay Elect Coop S4 Steve Wallace - Seminole Elect Coop S4 Ted Hobson – JEA, S1	would not agree that the RA has the ultimate responsibility to establish all SOLs. If the RA is what we call today a control area, we would agree that is where the ultimate responsibility lies. In our minds this question is still a critical area that NERC must address so that the industry understands how to review these. We are also unsure why you asked this particular question since standard 604, Requirement 1.1 states that the RA, PA and TOp shall establish the SOLs for the areas they are responsible. Are we missing something?? Response: Response: The standard acknowledges that the RA, PA and TOP all have a role in the determination of operating limits, much as the Functional Model does. It is assumed that further revisions of the Functional Model will add greater clarity in this area, especially regarding the relationship between Reliability Authorities and what we know today as Reliability Coordinators.
Gary Won – IMO S2	Yes.
Guy Zito, **NPCC CP9** Michael Schiavone – Nat Grid USA, S1 Roger Champagne – HQ Transenergie, S1 Ralph Rufrano – NYPA, S1 David Little – Nova Scotia Power, S1 David Kiguel – Hydro One, S1 Michael Potishnak – ISONE, S2 Barry Gee, Nat Grid USA, S1 Dan Stosick – ISONE, S2 Fernando Saavedra – ISONE, S2 Greg Campoli – NYISO, S2	Yes.
William J Smith – Allegheny Power, Segment 1	Yes.
Ken Githens – Allegheny Energy Supply – Segment 5	No. Others such as generator or transmission owners would have input. Response: These entities do have the responsibility to rate their facilities, and this is a key input into the establishment of system operating limits. These entities do not actually establish system operating limits, though.
Charles Yeung – Reliant Energy, S5	No. Unless there is accountability between what transmission tariff administrators are “selling” and what a transmission owner is allowing to be sold, the grid will not be optimized for market and reliability purposes. Since the NERC standard does not require a certain “footprint” for the RA, certain RAs that encompass only a single or a limited number of transmission owners will not have adequate information to properly assess simultaneous transfer capability. The goal of calculating a feasible simultaneous transfer limit should be a part of this standard and all Ras should be required to coordinate with their neighbors to set agreed upon Transfer Capability. Individualized, uncoordinated Transfer Capability values are detrimental to grid reliability and markets. Response: There is a separate standard being developed to address coordination between RAS. This standard does not address ATC, respecting the industry consensus observed during the SAR stage.
Kathleen Goodman – ISONE, S2	Yes.

2. Do you agree that identifying and communicating all system operating limits is within the scope of this standard and is necessary for reliability?

NERC Transmission Subcommittee Robert Reed – PJM Daniel Cooper – Michigan Public Power Agency Ken Donohoo – ERCOT Michael Gildea – Duke-Energy, North America Francis Halpin – BPA Tom Mallinger – MISO Darrick Moe – WAPA Scott Moore – AEP Bill Slater – Florida Power Corp Tom Stuchlik – Western Resources Joseph Styslinger – Southern Co David Thorne – DH Thorne Consultants Robert Waldele – NYISO Roman Carter – Southern Co John Ahr – Allegheny Power Susan Morris – SERC Ed Pfeiffer – Ameren Ray Palmieri – ECAR	Yes.
Mark Heimbach – PPL Generation, Segment 5	Yes.
Roman Carter (& 9 other employees) - Southern Company Generation and Marketing, Segments 5,6 Terry Crawley & Roger Green – SOCO Generation, Segment 5	Yes.
R T Sikes (& 4 other employees) – CenterPoint Energy Real Time Operations	Yes.
Alan Johnson – Mirant Americas Energy Mktg, Segment 6	Yes.
SERC Planning Standards Working Group Clay Young – South Carolina Electric & Gas, Segment 3 Byron Stewart – TVA, S1 David Weekly – Municipal Electric Authority of	Yes.

Georgia – S1 Brian Moss – Duke Power, S1 Darrell Pace – Alabama Electric Cooperative, S1 Bob Jones – SoCo, S1 Kham Vongkhamchanh – Entergy, S1 Pat Huntley – SERC, S2	
SERC Operations Planning Subcommittee Carter Edge – Southeastern Power Administration, S4&S5 William Gaither – South Carolina Public Service Auth, S1 Mike Miller – SoCo, S1 Roger Brand – Municipal Electric Authority of Georgia, S1 Phil Creech – Progress Energy (Carolina), S1 Gene Delk & Al McMeekin – South Carolina Electric and Gas, S1 Greg Ott – Alcoa/Yadkin, S1 Doug Newbauer – Georgia System Operations, S1 Mike Clements & Mark Creech – TVA, S1 Don Reichenbach – Duke Energy, S1 Lynna Estep – SERC, S2	Yes.
Robert Grover – PPL, S3	Neither yes or no. The issue that may arise relates to the word “all”. If a condition arises that necessitated a limit, but none was calculated either because the methodology was inadequate or because the conditions were ‘not credible’, would the RA be in non-compliance? What if the system was operated to avoid the problem occurring – now you have a non-event on a beyond max credible condition, would the RA be non-compliant? Does the Team mean “all” SOLs? or all “credible’ SOLs? Or all SOLs under mandated study conditions (this would leave the conditions subject to a Region or an RRO). Response: The standard requires that appropriate system operating limits be available for existing system conditions. Requirement 603 identifies the level of contingency analysis and system performance expected in the determination of system operating limits. By “all” the drafting team meant not just SOLs having wide-spread impacts, but also those that some may classify as “local” impacts.
John Horakh – MAAC, S2	Yes. Yes, as long as “all” means all limits determined by methodology bounded by the

	"Normal and Contingency Conditions" table included in this Standard. Response: Agreed.
David Thorne – PEPCO, S1	Same comments as Robert Grover, PPL, above.
Todd Lucas & 5 other employees – SoCo Trans Plng, S1 and S3	Yes.
Lee Westbrook – OnCor, S1	Yes. Identification and Communication of limits that vary continually in real time should be on a "best efforts" basis, and may include as little as a description of the real-time determination process. Response: This is not inconsistent with the standard, assuming the commenter means that limits automatically calculated and input to the EMS are available in real-time. The standard requires that appropriate system operating limits be available for existing system conditions. Requirement 603 identifies the level of contingency analysis and system performance expected in the determination of system operating limits.
Darrel Richardson – Illinois Power, S1 S2	Yes.
Ed Davis – Entergy, S1	Yes.
MAPP Operations Subcommittee Allan Silk – Manitoba Hydro Paul Brune – NPPD Paul Koskela – Minnesota Power Larry Larson – Otter Tail Darrick Moe – WAPA Dick Pursley – Great River Energy Martin Trence – Xcel Energy Todd Gosnell – Omaha PPD Joseph Knight – MAPPCOR, S2	Yes.
Clay Young and 8 employees – South Carolina Electric & Gas, S1, S3, S5	Yes.
Paul Johnson – AEP, S1,S3,S5, S6	Yes.
Dilip Mahendra – SMUD, S1	Yes.
James Spearman & Florence Belser – PSC of S. Carolina, S9	Yes.
SPP Operating Reliability WG Gerry Burrows – KCP&L, S1 Bob Cochran – SPS, S1 Peter Kuebeck – OG&E, S1 Scott Moore – AEP, S1 Dan Boezio – AEP, S1 Tom Stuchlik – Westar, S1 Matt Bordelon – CLECO, S1 Mike Crouch – WFEC, S1	Yes.

Mike Gammon – KCP&L, S1 Kevin Goolsby – SPP, S2 Bo Jones – Westar, S1 Allen Klassen – Westar, S1 Thad Ness – AEP, S1 Harold Wyble – KCP&L, S1 Robert Rhodes – SPP, S2	
John Blazekovich - Exelon, S1,S3,S5,S6	Yes. The "Purpose" on page 2 of the standard does not cover "all" system operating limits, but only those that result in cascading outages, uncontrolled separation, and voltage and transient instability and is not consistent with the SOL definition (page 1 of the Standard). The following wording change is suggested: "To determine all facility ratings, system operating limits and transfer capabilities necessary to plan and operate the bulk electric system within predefined facility and operating limits." Response: The purpose has been revised to add greater clarity in response to this and other comments.
Carter Edge – S.E. Power Admin, S4, S5	Yes.
Tom Pruitt & 4 other employees – Duke Power, S1 & S5	Yes.
Alan Boesch – NPPD, S1	Yes.
Tony Jankowski – We Energies, S4	Yes.
Don Chandler – CenterPoint, S1	Yes.
Tom Mielnik – MidAmerican, S3	Yes.
Michael Sidiropoulos – Pacificorp, S1	Yes.
Mitchell Needham – TVA, S1 Gary L. Jackson – TVA, S6 Mark Creech - TVA	Yes.
Mike Viles & 9 other employees – BPA Transmission, S1	Yes.
Carey Gates – CalISO, S2	Yes.
Susan Morris – SERC, S2 Bill Reinke – SERC, S2 Sam Stryker – Fayetteville PWS, S3, S4, S5 John Stickley – AECI, S1 Carter Edge – SEPA, S4,S5 John Troha – SERC, S2 Tim Ponseti – TVA, S1 Bill Thompson – Dominion Transmission, S1	Yes.
Gerald Rheault – Manitoba Hydro, S1, S3, S5, S6	Yes.
Peter Burke – American Transmission Company, S1	Yes.

Kirit Shah – Ameren, S1	No. This standard includes determining system operating limits for both real-time operations and planning studies. We believe that standard to determine system operating limits and ratings for planning studies should be seperated. Response: During the development of the SAR associated with this standard, it was decided that the best course was to develop the all the requirements as part of the same standard. There appears to be no appreciable benefit to splitting the pieces out, as each is already a separate requirement.
WECC Technical Studies Subcommittee Peter Mackin – Trans Agency of Northern Calif, S1 Chifong Thomas – Pacific G&E, S1 Esteban Martinez – Turlock Irrigation District, S1 Peter Krzykos – Ariz Public Service, S1 Joe Seabrook – Puget Sound, A1 Phil Park – BC Trans Co, S1 C V Chung – Seattle City Light, S9	Yes.
FRCC OC, EC, MIC Linda Campbell – FRCC, S2 Paul Elwing – Lakeland Electric, S3 John Shafer – FP&L, S1 Don McInnis – FP&L S1 Patti Metro – FRCC, S2 Joe Krupar – FMPA, S3 Richard Gilbert – Lakeland Elect S3 Amy Long – Lakeland Elect S1 Roger Westphal – Gainesville Regional Utilities S5 Bob Remley – Clay Elect Coop S4 Steve Wallace - Seminole Elect Coop S4 Ted Hobson – JEA, S1	No. Identifying and communicating all SOLs is too broad of a requirement. "All" should only apply to bulk electric system facilities. Response: The standard requires that appropriate system operating limits be available for existing system conditions. Requirement 603 identifies the level of contingency analysis and system performance expected in the determination of system operating limits. By “all” the drafting team meant not just SOLs having wide-spread impacts, but also those that some may classify as “local” impacts.
Gary Won – IMO S2	Yes.
William J Smith – Allegheny Power, Segment 1	Yes.
Guy Zito, **NPCC CP9** Michael Schiavone – Nat Grid USA, S1 Roger Champagne – HQ Transenergie, S1 Ralph Rufrano – NYPA, S1 David Little – Nova Scotia Power, S1 David Kiguel – Hydro One, S1	Yes.

Michael Potishnak – ISONE, S2 Barry Gee, Nat Grid USA, S1 Dan Stosick – ISONE, S2 Fernando Saavedra – ISONE, S2 Greg Campoli – NYISO, S2	
Ken Githens – Allegheny Energy Supply – Segment 5	Yes. However, refer to the comments to the final question. Response: Please see response to Mr. Githens' final question.
Charles Yeung – Reliant Energy, S5	No. Communication of this data is necessary – but may be covered in another standard. Does the Coordinate Operations Standard require the communication of such data already? Response: The drafting team will coordinate with the Coordinate Operations standard team when they begin drafting their standard to ensure that the requirements are not duplicated.
Kathleen Goodman – ISONE, S2	Yes.

3. **NERC Regions have the right to ask for Regional differences for inclusion in NERC standards. Such differences would apply only to the listed Region and would become an enforceable part of the NERC standard only if approved by the industry. NPCC has requested a Regional difference in section 603. Do you think NPCC's Regional difference should be included in this standard**?

NERC Transmission Subcommittee Robert Reed – PJM Daniel Cooper – Michigan Public Power Agency Ken Donohoo – ERCOT Michael Gildea – Duke-Energy, North America Francis Halpin – BPA Tom Mallinger – MISO Darrick Moe – WAPA Scott Moore – AEP Bill Slater – Florida Power Corp Tom Stuchlik – Western Resources Joseph Styslinger – Southern Co David Thorne – DH Thorne Consultants Robert Waldele – NYISO Roman Carter – Southern Co John Ahr – Allegheny Power Susan Morris – SERC Ed Pfeiffer – Ameren Ray Palmieri – ECAR	No. The Transmission Subcommittee (TS) does not recommend incorporating more conservative regional requirements into the NERC standards. The TS recommends the "Regional Differences" be restricted to differences that include variances in a less conservative direction, differences in terminology, and differences in methodology in accomplishing the standard expectations or requirements. The TS recommends the more conservative regional requirements be incorporated into regional standards or procedures. Response: The drafting team understands this position. However, the NERC process allows Regions to seek incorporation of more stringent requirements if they desire. The manual allows for Regional differences as long as they: ▪ Are developed in fair and open process ▪ Do not have a significant adverse impact on commerce that is not necessary for reliability ▪ Provide an appropriate level of bulk system reliability ▪ Are based upon a justifiable difference between Regions or subregions
Mark Heimbach – PPL Generation, Segment 5	Yes.
Roman Carter (& 9 other employees) - Southern Company Generation and Marketing, Segments 5,6	Yes.

Terry Crawley & Roger Green – SOCO Generation, Segment 5	
R T Sikes (& 4 other employees) – CenterPoint Energy Real Time Operations	Yes.
Alan Johnson – Mirant Americas Energy Mktg, Segment 6	No. It seems that NPCC has requested a higher level of reliability by setting requirements for operating under multiple contingencies. Believe NPCC should have the ability to do this, subject to membership approval. However, this does not appear to be a "Regional Difference" in the true spirit of the phrase. As such, it would be cleaner to not include it as part of the NERC standard and allow NPCC to implement regionally. Response: The drafting team understands this position. However, the NERC process allows Regions to seek incorporation of more stringent requirements if they desire. The manual allows for Regional differences as long as they: ▪ Are developed in fair and open process ▪ Do not have a significant adverse impact on commerce that is not necessary for reliability ▪ Provide an appropriate level of bulk system reliability ▪ Are based upon a justifiable difference between Regions or subregions
SERC Planning Standards Working Group Clay Young – South Carolina Electric & Gas, Segment 3 Byron Stewart – TVA, S1 David Weekly – Municipal Electric Authority of Georgia – S1 Brian Moss – Duke Power, S1 Darrell Pace – Alabama Electric Cooperative, S1 Bob Jones – SoCo, S1 Kham Vongkhamchanh – Entergy, S1 Pat Huntley – SERC, S2	Yes. However, if our recommendation in question # 12 (#8 in this document) below is adopted inclusion of specific regional differences would no longer be needed. Response: The NERC requirement is intended as a minimum and Regions do have the right to use more stringent requirements if they choose. These requirements need not be included in the NERC standard if the Region does not wish for NERC to enforce them in that Region.
SERC Operations Planning Subcommittee Carter Edge – Southeastern Power Administration, S4&S5 William Gaither – South Carolina Public Service Auth, S1 Mike Miller – SoCo, S1 Roger Brand – Municipal Electric Authority of Georgia, S1 Phil Creech – Progress Energy (Carolina), S1 Gene Delk & Al McMeekin – South Carolina Electric and Gas, S1 Greg Ott – Alcoa/Yadkin, S1 Doug Newbauer – Georgia System Operations, S1 Mike Clements & Mark Creech –	Yes. Same comments as SERC Planning Standards Working Group listed above.

TVA, S1 Don Reichenbach – Duke Energy, S1 Lynna Estep – SERC, S2	
Robert Grover – PPL, S3	Yes.
John Horakh – MAAC, S2	Yes.
David Thorne – PEPCO, S1	Yes.
Todd Lucas & 5 other employees – SoCo Trans Plng, S1 and S3	Yes.
Lee Westbrook – OnCor, S1	No. Regional differences are more properly applied to exemptions from all or parts of NERC Standards than to extensions of those Standards. Response: The drafting team understands this position. However, the NERC process allows Regions to seek incorporation of more stringent requirements if they desire. The manual allows for Regional differences as long as they: ▪ Are developed in fair and open process ▪ Do not have a significant adverse impact on commerce that is not necessary for reliability ▪ Provide an appropriate level of bulk system reliability ▪ Are based upon a justifiable difference between Regions or subregions
Darrel Richardson – Illinois Power, S1 S2	Yes.
Ed Davis – Entergy, S1	Yes. Regional difference should be accommodated so long as they are not detrimental to the Interconnection. Response: This is consistent with the NERC standards process.
MAPP Operations Subcommittee Allan Silk – Manitoba Hydro Paul Brune – NPPD Paul Koskela – Minnesota Power Larry Larson – Otter Tail Darrick Moe – WAPA Dick Pursley – Great River Energy Martin Trence – Xcel Energy Todd Gosnell – Omaha PPD Joseph Knight – MAPPCOR, S2	Yes.
Clay Young and 8 employees – South Carolina Electric & Gas, S1, S3, S5	Yes. However, if our recommendation in question # 12 (#8 in this document) below is adopted inclusion of specific regional differences would no longer be needed. See SERC response above.
Paul Johnson – AEP, S1,S3,S5, S6	No. A regional difference should be reserved for situations where due to the particular situation of a region, the standard is not practical or appropriate to apply in that locale. The Regional difference should facilitate a new (minimum) standard that would be appropriate for that situation in lieu of the standard applicable to the other

	parts of NERC. A Region (or any other entity) can always exceed this minimum requirement. As proposed, NPCC is requesting inclusion of a Regional difference that exceeds the proposed minimum performance level proposed in this particular standard. Although there is no obvious negative in this particular case, having a more 'robust' Regional standard included in the NERC Standard is bad policy and precedent. Any Region can place themselves under a 'higher standard', which in this case would be a more appropriate avenue. Response: The drafting team understands this position. However, the NERC process allows Regions to seek incorporation of more stringent requirements if they desire. The manual allows for Regional differences as long as they: ▪ Are developed in fair and open process ▪ Do not have a significant adverse impact on commerce that is not necessary for reliability ▪ Provide an appropriate level of bulk system reliability ▪ Are based upon a justifiable difference between Regions or subregions
Dilip Mahendra – SMUD, S1	No.
James Spearman & Florence Belser – PSC of S. Carolina, S9	Yes.
SPP Operating Reliability WG Gerry Burrows – KCP&L, S1 Bob Cochran – SPS, S1 Peter Kuebeck – OG&E, S1 Scott Moore – AEP, S1 Dan Boezio – AEP, S1 Tom Stuchlik – Westar, S1 Matt Bordelon – CLECO, S1 Mike Crouch – WFEC, S1 Mike Gammon – KCP&L, S1 Kevin Goolsby – SPP, S2 Bo Jones – Westar, S1 Allen Klassen – Westar, S1 Thad Ness – AEP, S1 Harold Wyble – KCP&L, S1 Robert Rhodes – SPP, S2	No. Additional regional criteria that go beyond the NERC requirements should be contained in regional agreements not in the NERC standard. Only regional differences that do not meet the NERC minimal requirements should be included in NERC standards. Response: The drafting team understands this position. However, the NERC process allows Regions to seek incorporation of more stringent requirements if they desire. The manual allows for Regional differences as long as they: ▪ Are developed in fair and open process ▪ Do not have a significant adverse impact on commerce that is not necessary for reliability ▪ Provide an appropriate level of bulk system reliability ▪ Are based upon a justifiable difference between Regions or subregions
John Blazekovich - Exelon, S1,S3,S5,S6	Yes.
Raymond Mammarella – PPL, S1	Yes.
Carter Edge – S.E. Power Admin, S4, S5	Yes. Same comments as SERC Planning Standards Working Group listed above.
Tom Pruitt & 4 other employees – Duke Power, S1 & S5	No. This difference creates a potential market issue allowing restriction of business (due to lower probability events) than restrictions applied in other regions. Response: NPCC has been contacted and will develop a paper explaining their requested Regional difference. This paper will be posted when the standard is posted for ballot.
Alan Boesch – NPPD, S1	Yes.
Tony Jankowski – We Energies, S4	No. Believe elements of the NPCC criteria should be applicable to all. Should be able

	to develop a common table for an interconnect. Response: The NPCC criteria exceed that of most of the NERC Regions. There is no consensus to require all areas to meet the NPCC criteria.
Don Chandler – CenterPoint, S1	Yes.
Tom Mielnik – MidAmerican, S3	Yes.
Michael Sidiropoulos – Pacificorp, S1	Yes.
Mitchell Needham – TVA, S1 Gary L. Jackson – TVA, S6 Mark Creech - TVA	Yes.
Mike Viles & 9 other employees – BPA Transmission, S1	Yes. Defining NPCC is requested. Response: NPCC stands for Northeast Power Coordinating Council, one of the 10 NERC Regional Councils.
Carey Gates – CalISO, S2	No. NPCC is seeking to establish a standard that is more stringent than the NERC standard. The NERC standard should be developed to apply to all regions wherever possible. If a region desires to establish a more stringent standard for their individual region they should develop it as a regional standard outside the NERC Reliability Standard process. Conversely, regions should not develop standards that would be less stringent than the NERC Reliability Standards. The regional difference prevision should be reserved for parts of a standard that do not apply and not be implemented by a region. Response: The drafting team understands this position. However, the NERC process allows Regions to seek incorporation of more stringent requirements if they desire. The manual allows for Regional differences as long as they: ▪ Are developed in fair and open process ▪ Do not have a significant adverse impact on commerce that is not necessary for reliability ▪ Provide an appropriate level of bulk system reliability ▪ Are based upon a justifiable difference between Regions or subregions
Susan Morris – SERC, S2 Bill Reinke – SERC, S2 Sam Stryker – Fayetteville PWS, S3, S4, S5 John Stickley – AECI, S1 Carter Edge – SEPA, S4,S5 John Troha – SERC, S2 Tim Ponseti – TVA, S1 Bill Thompson – Dominion Transmission, S1	No. Regional difference should be accommodated so long as they are not detrimental to the Interconnection. However, having those differences incorporated into the NERC standards seems ripe for introducing confusion into the NERC standards. If the region's have differences they should be documented in separate regional documents (like the SERC supplements), and reviewed by NERC to ensure they do not relax the NERC standards. Having NPCC shown with a table IA in the NERC standard, which more closely resembles the original IA Standard table, just stands out like a sore thumb. Response: The drafting team understands this position. However, the NERC process allows Regions to seek incorporation of more stringent requirements if they desire. The manual allows for Regional differences as long as they: ▪ Are developed in fair and open process ▪ Do not have a significant adverse impact on commerce that is not necessary for reliability ▪ Provide an appropriate level of bulk system reliability

	▪ Are based upon a justifiable difference between Regions or subregions
Gerald Rheault – Manitoba Hydro, S1, S3, S5, S6	No. Manitoba Hydro agrees with the table in 603 and sees no justification for going further. The treatment of more than first contingency must be consistent with the rationale for investment in the system. It is fine to consider levels C and D in system studies but NOT in the establishment of system limits. When a Region wants to establish one that is more stringent, this should be established as a regional Standard only. NERC should set the minimum reliability Standards for the entire grid. A Region can't be less stringent than NERC but they can be more stringent. This region can monitor the entities within the region for the more stringent regional Standard. In this case when the regional entities are compliant with the more stringent regional Standard they are also compliant with the NERC Standard. Response: The drafting team understands this position. However, the NERC process allows Regions to seek incorporation of more stringent requirements if they desire. The manual allows for Regional differences as long as they: ▪ Are developed in fair and open process ▪ Do not have a significant adverse impact on commerce that is not necessary for reliability ▪ Provide an appropriate level of bulk system reliability ▪ Are based upon a justifiable difference between Regions or subregions
Peter Burke – American Transmission Company, S1	Yes. If it not mentioned in the standard then the other regions would not really know what differences apply.
Kirit Shah – Ameren, S1	No. The standard should define minimum criteria which should be met by all NERC regions. NERC Regions can have their own criteria which could be more stringent then the NERC criteria. Response: The drafting team understands this position. However, the NERC process allows Regions to seek incorporation of more stringent requirements if they desire. The manual allows for Regional differences as long as they: ▪ Are developed in fair and open process ▪ Do not have a significant adverse impact on commerce that is not necessary for reliability ▪ Provide an appropriate level of bulk system reliability ▪ Are based upon a justifiable difference between Regions or subregions
WECC Technical Studies Subcommittee Peter Mackin – Trans Agency of Northern Calif, S1 Chifong Thomas – Pacific G&E, S1 Esteban Martinez – Turlock Irrigation District, S1 Peter Krzykos – Ariz Public Service, S1 Joe Seabrook – Puget Sound, A1 Phil Park – BC Trans Co, S1 C V Chung – Seattle City Light, S9	Yes.
FRCC OC, EC, MIC	Yes.

Linda Campbell – FRCC, S2 Paul Elwing – Lakeland Electric, S3 John Shafer – FP&L, S1 Don McInnis – FP&L S1 Patti Metro – FRCC, S2 Joe Krupar – FMPA, S3 Richard Gilbert – Lakeland Elect S3 Amy Long – Lakeland Elect S1 Roger Westphal – Gainesville Regional Utilities S5 Bob Remley – Clay Elect Coop S4 Steve Wallace - Seminole Elect Coop S4 Ted Hobson – JEA, S1	We support regional differences, but they should not create problems in other regions. Response: Regional differences must be developed in a manner to ensure that reliability problems are not caused on other Regions, as indicated by this comment.
Gary Won – IMO S2	Yes. The NPCC criteria is more stringent than the NERC standard.
William J Smith – Allegheny Power, Segment 1	Yes.
Guy Zito, **NPCC CP9** Michael Schiavone – Nat Grid USA, S1 Roger Champagne – HQ Transenergie, S1 Ralph Rufrano – NYPA, S1 David Little – Nova Scotia Power, S1 David Kiguel – Hydro One, S1 Michael Potishnak – ISONE, S2 Barry Gee, Nat Grid USA, S1 Dan Stosick – ISONE, S2 Fernando Saavedra – ISONE, S2 Greg Campoli – NYISO, S2	This needs to be further discussed within NPCC's membership and will be decided at an upcoming NPCC Executive Committee meeting. Response: NPCC has been contacted and they wish to include the difference in the standard when it is balloted.
Ken Githens – Allegheny Energy Supply – Segment 5	Yes.
Charles Yeung – Reliant Energy, S5	No. Since the NPCC Regional Requirements mirror the overall NERC Standard but with the addition of Section C in Table IA, could the double contingency requirements contained in Section C Table IA be excluded from the NERC standard and instead be an addendum to NPCC members' requirements on a Regional basis? In other words, the Section A and B requirements appear to be common operating limit requirements for all NERC members. NERC must establish a consistent approach in how to handle Regional differences in these Organization Standards that are intended to be applicable to all NERC members, regardless of Regional Council affiliation. Response: The consistent approach requested is already contained in the NERC standards process manual. Regions have the right to request a Regional difference, provided they fulfill the requirements in the manual. The suggestion that NPCC's more stringent requirements be made a separate NPCC standard, as opposed to a NERC one, is a workable solution. However, NPCC wishes for NERC to enforce this requirement in NPCC and the only way to do so is to include it in the standard.
Kathleen Goodman – ISONE, S2	No.

	ISO-NE believes, if these Standards continue to include the Monetary Sanctions as they currently do, only less-stringent, by-exception, Regional differences should be included. Although ISO-NE supports NPCC's reliability standards, we cannot support including them in a NERC Standard, which has monetary sanctions associated with it, given our lack of support of such sanctions as an enforcement mechanism. Response: The drafting team respects this position. However, NERC reserves the right to levy financial sanctions, where appropriate, for violations of its standards. Such sanctions would be identified in the proposed standard and would be applied if the industry supported them. This comment will be shared with NERC's General Counsel and Director of Compliance.

4. **Are you aware of any other Regional differences that should be included in this standard?**

NERC Transmission Subcommittee Robert Reed – PJM Daniel Cooper – Michigan Public Power Agency Ken Donohoo – ERCOT Michael Gildea – Duke-Energy, North America Francis Halpin – BPA Tom Mallinger – MISO Darrick Moe – WAPA Scott Moore – AEP Bill Slater – Florida Power Corp Tom Stuchlik – Western Resources Joseph Styslinger – Southern Co David Thorne – DH Thorne Consultants Robert Waldele – NYISO Roman Carter – Southern Co John Ahr – Allegheny Power Susan Morris – SERC Ed Pfeiffer – Ameren Ray Palmieri – ECAR	No.
Mark Heimbach – PPL Generation, Segment 5	No.
R T Sikes (& 4 other employees) – CenterPoint Energy Real Time Operations	No.
Alan Johnson – Mirant Americas Energy Mktg, Segment 6	No.
SERC Planning Standards Working Group Clay Young – South Carolina Electric & Gas, Segment 3 Byron Stewart – TVA, S1 David Weekly – Municipal Electric Authority of Georgia – S1 Brian Moss – Duke Power, S1	No. However, if our comment in question # 12 (#8 in this document) below is not accepted, SERC may consider requesting a Regional difference.

Darrell Pace – Alabama Electric Cooperative, S1 Bob Jones – SoCo, S1 Kham Vongkhamchanh – Entergy, S1 Pat Huntley – SERC, S2	
SERC Operations Planning Subcommittee Carter Edge – Southeastern Power Administration, S4&S5 William Gaither – South Carolina Public Service Auth, S1 Mike Miller – SoCo, S1 Roger Brand – Municipal Electric Authority of Georgia, S1 Phil Creech – Progress Energy (Carolina), S1 Gene Delk & Al McMeekin – South Carolina Electric and Gas, S1 Greg Ott – Alcoa/Yadkin, S1 Doug Newbauer – Georgia System Operations, S1 Mike Clements & Mark Creech – TVA, S1 Don Reichenbach – Duke Energy, S1 Lynna Estep – SERC, S2	No. Same comments as SERC Planning Standards Working Group listed above.
Robert Grover – PPL, S3	No.
John Horakh – MAAC, S2	No.
David Thorne – PEPCO, S1	No.
Todd Lucas & 5 other employees – SoCo Trans Plng, S1 and S3	No. We do not currently know of any Regional differences at this time. However, during the initial phasing in of standards each region may find adopting or developing a different approach provides increased reliability. Therefore, we believe that differences should be considered as they are identified in the future. Response: The NERC standards development process allows for Regional differences to be added to approved standards, but that must be accomplished via a SAR requesting a modification to the existing standard.
Lee Westbrook – OnCor, S1	No.
Darrel Richardson – Illinois Power, S1 S2	No.
Ed Davis – Entergy, S1	Yes. Any “methodology” for establishing ratings, operating limits, and / or transfer capabilities may have individual owner differences as well as Regional differences. Response: The standard allows for differences in the referenced methodologies. Facility owners do not establish system operating limits or transfer capabilities, as prescribed in the functional model and this standard.
MAPP Operations Subcommittee Allan Silk – Manitoba Hydro	Yes. MAPP also has a regional difference in section 603.1. The table referred to under

Paul Brune – NPPD Paul Koskela – Minnesota Power Larry Larson – Otter Tail Darrick Moe – WAPA Dick Pursley – Great River Energy Martin Trence – Xcel Energy Todd Gosnell – Omaha PPD Joseph Knight – MAPPCOR, S2	question 12 was developed using an open comment process. Response: This issue has been discussed with MAPP and they are withdrawing this regional difference.
Clay Young and 8 employees – South Carolina Electric & Gas, S1, S3, S5	No. However, if our comment in question # 12 below is not accepted, SCE&G will insist that SERC request a Regional difference.
Paul Johnson – AEP, S1,S3,S5, S6	No. No, generally, A Regional difference should be used to exempt a Region from a particular aspect of a standard and make that Region subject to requirements that would achieve a comparable performance objective. Response: The drafting team understands this position. However, the NERC process allows Regions to seek incorporation of more stringent requirements if they desire. The manual allows for Regional differences as long as they: ▪ Are developed in fair and open process ▪ Do not have a significant adverse impact on commerce that is not necessary for reliability ▪ Provide an appropriate level of bulk system reliability ▪ Are based upon a justifiable difference between Regions or subregions
Dilip Mahendra – SMUD, S1	No.
James Spearman & Florence Belser – PSC of S. Carolina, S9	No.
SPP Operating Reliability WG Gerry Burrows – KCP&L, S1 Bob Cochran – SPS, S1 Peter Kuebeck – OG&E, S1 Scott Moore – AEP, S1 Dan Boezio – AEP, S1 Tom Stuchlik – Westar, S1 Matt Bordelon – CLECO, S1 Mike Crouch – WFEC, S1 Mike Gammon – KCP&L, S1 Kevin Goolsby – SPP, S2 Bo Jones – Westar, S1 Allen Klassen – Westar, S1 Thad Ness – AEP, S1 Harold Wyble – KCP&L, S1 Robert Rhodes – SPP, S2	No.
John Blazekovich - Exelon, S1,S3,S5,S6	No.
Raymond Mammarella – PPL, S1	No.
Carter Edge – S.E. Power Admin, S4, S5	No.

	Same comments as SERC Planning Standards Working Group listed above.
Tom Pruitt & 4 other employees – Duke Power, S1 & S5	No.
Alan Boesch – NPPD, S1	No.
Tony Jankowski – We Energies, S4	No.
Don Chandler – CenterPoint, S1	No.
Tom Mielnik – MidAmerican, S3	No. MidAmerican Energy Company is a member of MAPP. MAPP's current standards are consistent with the old existing NERC Standards that required the system to be planned and operated to Categories A through D. However, MidAmerican Energy believes that many members of MAPP do not comply with these standards in the operating horizon with regard to Category C and some do not comply with these standards in the planning horizon with regard to Category C. Recent MAPP adoption of new forms of NERC Standards augmented with MAPP standards were based upon the assumption that NERC required systems to operate to Category C. MidAmerican was planning on preparing waivers with a plan for compliance until MidAmerican could build additional facilities to allow Category C to be met in the planning horizon. Under the current NERC proposal, MidAmerican would urge MAPP NOT to adopt any standard which is beyond the NERC requirement. In today's environment, adoption of Category C will result in numerous TLR calls and much additional investment with potentially relatively small customer benefit. MidAmerican does believe that it makes sense to review Category C and D events for likelihood of the event and the consequences of the event. Those C and D events that are more likely, such as stuck breaker events for a style of breaker that has been found to have the propensity to stick, or those C and D events that result in significant consequences, such as cascading outages, should be considered for inclusion in determining OSL. However, MidAmerican believes that this is the standard that NERC should adopt for all regions. This is not a standard that MAPP should adopt as a regional difference. In any case, any MAPP regional difference that is added to this standard by NERC should be the result of a new open discussion process at MAPP recognizing that NERC is now proposing not to include C and D events in the NERC standard for setting OSL. Therefore, MidAmerican Energy asks NERC NOT to adopt a MAPP Regional Difference until MAPP conducts such a new open discussion process. Response: This issue has been discussed with MAPP and they are withdrawing this regional difference.
Michael Sidiropoulos – Pacificorp, S1	No.
Mitchell Needham – TVA, S1 Gary L. Jackson – TVA, S6 Mark Creech - TVA	No.
Mike Viles & 9 other employees – BPA Transmission, S1	Yes. Not all regions determine Transfer Capabilities. This standard should not make Transfer Capabilities a requirement if they are not needed for reliable operation of the transmission system. Response: The standard does not require transfer capability determination if there is no user of the information.
Carey Gates – CalISO, S2	No. Note: WECC does currently have regional standards that are more stringent than the NERC Policies and could remain in effect after the transition to Reliability Standards.

	Response: The NERC requirement is intended as a minimum and Regions do have the right to employ more stringent requirements if they choose. These requirements need not be included in the NERC standard if the Region does not wish for NERC to enforce them in that Region.
Susan Morris – SERC, S2 Bill Reinke – SERC, S2 Sam Stryker – Fayetteville PWS, S3, S4, S5 John Stickley – AECI, S1 Carter Edge – SEPA, S4,S5 John Troha – SERC, S2 Tim Ponseti – TVA, S1 Bill Thompson – Dominion Transmission, S1	Yes. Any "methodology" for establishing ratings, operating limits, and / or transfer capabilities may have individual owner differences as well as Regional differences. This should be stated under the Regional Differences Section for each standard requiring the documentation of methodologies. Response: The standard allows for differences in the referenced methodologies. Facility owners do not establish system operating limits or transfer capabilities, as prescribed in the functional model and this standard.
Gerald Rheault – Manitoba Hydro, S1, S3, S5, S6	No. In its submission, MAPP has indicated they have a Regional difference referenced as table 1 at the end of their comments submitted for this Standard. Manitoba Hydro has reservations in endorsing this proposed Regional difference and believes there is a need for further review by all MAPP members and the MAPP Regional Reliability Council before this table can be declared a Regional difference in this Standard. Response: This issue has been discussed with MAPP and they are withdrawing this regional difference.
Peter Burke – American Transmission Company, S1	No.
Kirit Shah – Ameren, S1	No.
WECC Technical Studies Subcommittee Peter Mackin – Trans Agency of Northern Calif, S1 Chifong Thomas – Pacific G&E, S1 Esteban Martinez – Turlock Irrigation District, S1 Peter Krzykos – Ariz Public Service, S1 Joe Seabrook – Puget Sound, A1 Phil Park – BC Trans Co, S1 C V Chung – Seattle City Light, S9	No. For the WECC, the calculation of Transfer Capability should be mandatory only for those transfer paths for which the reliability authority determines that Transfer Capabilities are required for reliable operation of the system. Many entities only need to calculate System Operating Limits to establish reliable import / export limits for their respective systems. Unless the reliability authority determines that it is necessary, calculation of Transfer Capability would be an unnecessary burden with no commensurate benefit to reliable operation of the grid. Response: The standard does not require transfer capability determination if there is no user of the information.
FRCC OC, EC, MIC Linda Campbell – FRCC, S2 Paul Elwing – Lakeland Electric, S3 John Shafer – FP&L, S1 Don McInnis – FP&L S1 Patti Metro – FRCC, S2 Joe Krupar – FMPA, S3 Richard Gilbert – Lakeland Elect S3 Amy Long – Lakeland Elect S1 Roger Westphal – Gainesville Regional Utilities S5 Bob Remley – Clay Elect Coop S4 Steve Wallace - Seminole Elect	No.

Coop S4 Ted Hobson – JEA, S1	
Gary Won – IMO S2	Possibly ERCOT and WSCC will have differences. Response: These two Regions are not seeking any differences at this time.
William J Smith – Allegheny Power, Segment 1	No.
Guy Zito, **NPCC CP9** Michael Schiavone – Nat Grid USA, S1 Roger Champagne – HQ Transenergie, S1 Ralph Rufrano – NYPA, S1 David Little – Nova Scotia Power, S1 David Kiguel – Hydro One, S1 Michael Potishnak – ISONE, S2 Barry Gee, Nat Grid USA, S1 Dan Stosick – ISONE, S2 Fernando Saavedra – ISONE, S2 Greg Campoli – NYISO, S2	No.
Ken Githens – Allegheny Energy Supply – Segment 5	No.
Charles Yeung – Reliant Energy, S5	No.
Kathleen Goodman – ISONE, S2	No.

5. **Do you agree with the sanction philosophy in this standard? (No financial penalties for methodology violations, nominal fixed monetary penalties for failure to communicate values).**

NERC Transmission Subcommittee Robert Reed – PJM Daniel Cooper – Michigan Public Power Agency Ken Donohoo – ERCOT Michael Gildea – Duke-Energy, North America Francis Halpin – BPA Tom Mallinger – MISO Darrick Moe – WAPA Scott Moore – AEP Bill Slater – Florida Power Corp Tom Stuchlik – Western Resources Joseph Styslinger – Southern Co David Thorne – DH Thorne Consultants Robert Waldele – NYISO Roman Carter – Southern Co John Ahr – Allegheny Power Susan Morris – SERC Ed Pfeiffer – Ameren Ray Palmieri – ECAR	Unable to answer. The TS did not totally understand the “sanction methodology” or the above question. Instead of giving an inappropriate answer, the TS decided not to answer yes or no.
Mark Heimbach – PPL Generation,	Yes.

Segment 5	
Roman Carter (& 9 other employees) - Southern Company Generation and Marketing, Segments 5,6 Terry Crawley & Roger Green – SOCO Generation, Segment 5	Yes.
R T Sikes (& 4 other employees) – CenterPoint Energy Real Time Operations	Yes.
Alan Johnson – Mirant Americas Energy Mktg, Segment 6	No. Until legislation is passed enabling NERC as a reliability organization, Mirant does not believe that NERC should have the ability to assess financial penalties under this standard. However, if financial penalties are to be assessed, they should be assessed for methodology violations as well because use of an incorrect methodology could potentially lead to reliability problems. For example, suppose an entity uses a non-compliant methodology to determine a system limit, which results in the system limit being too high, resulting in the failure of a system component. Isn't this a reliability concern? Response: NERC's ability to enforce its standards is outside of the drafting team's scope. The drafting team agrees that methodology violations are reliability concerns. That is why the methodology is required in the standard and violations will result in sanctions. The majority of other commenters do not support the use of financial sanctions for document violations, so the suggestion was not incorporated into the standard.
SERC Planning Standards Working Group Clay Young – South Carolina Electric & Gas, Segment 3 Byron Stewart – TVA, S1 David Weekly – Municipal Electric Authority of Georgia – S1 Brian Moss – Duke Power, S1 Darrell Pace – Alabama Electric Cooperative, S1 Bob Jones – SoCo, S1 Kham Vongkhamchanh – Entergy, S1 Pat Huntley – SERC, S2	Yes.
SERC Operations Planning Subcommittee Carter Edge – Southeastern Power Administration, S4&S5 William Gaither – South Carolina Public Service Auth, S1 Mike Miller – SoCo, S1 Roger Brand – Municipal Electric Authority of Georgia, S1 Phil Creech – Progress Energy (Carolina), S1 Gene Delk & Al McMeekin – South	Yes.

Carolina Electric and Gas, S1 Greg Ott – Alcoa/Yadkin, S1 Doug Newbauer – Georgia System Operations, S1 Mike Clements & Mark Creech – TVA, S1 Don Reichenbach – Duke Energy, S1 Lynna Estep – SERC, S2	
Robert Grover – PPL, S3	Yes.
John Horakh – MAAC, S2	Yes.
David Thorne – PEPCO, S1	Yes.
Todd Lucas & 5 other employees – SoCo Trans Plng, S1 and S3	Yes. The approach should be allowed to continue unless and until it is demonstrated that philosophy is not effective.
Lee Westbrook – OnCor, S1	Yes.
Darrel Richardson – Illinois Power, S1 S2	No. It would seem that absence any penalties for methodology violations there would be little incentive to comply with the requirement. Response: There are penalties in the standard for methodology violations, but they are not financial in nature. The drafting team believes the penalties will be sufficient to incent the desired performance.
Ed Davis – Entergy, S1	Yes.
MAPP Operations Subcommittee Allan Silk – Manitoba Hydro Paul Brune – NPPD Paul Koskela – Minnesota Power Larry Larson – Otter Tail Darrick Moe – WAPA Dick Pursley – Great River Energy Martin Trence – Xcel Energy Todd Gosnell – Omaha PPD Joseph Knight – MAPPCOR, S2	Yes.
Clay Young and 8 employees – South Carolina Electric & Gas, S1, S3, S5	Yes.
Paul Johnson – AEP, S1,S3,S5, S6	Yes. This standard does not propose monetary sanctions for not having required 'paperwork', which is reasonable and appropriate. This standard will also apply fix dollar sanctions for repeated or serious violations for the unavailability of critical reliability data. This too is appropriate. Monetary sanctions based on 'partial credit', or 'per MW' would be arbitrary and likely unworkable. Response: Agreed.
Dilip Mahendra – SMUD, S1	Yes.
James Spearman & Florence Belser – PSC of S. Carolina, S9	Yes.
SPP Operating Reliability WG Gerry Burrows – KCP&L, S1 Bob Cochran – SPS, S1	No. If an incorrect limit is calculated or a limit is not communicated, the financial

Peter Kuebeck – OG&E, S1 Scott Moore – AEP, S1 Dan Boezio – AEP, S1 Tom Stuchlik – Westar, S1 Matt Bordelon – CLECO, S1 Mike Crouch – WFEC, S1 Mike Gammon – KCP&L, S1 Kevin Goolsby – SPP, S2 Bo Jones – Westar, S1 Allen Klassen – Westar, S1 Thad Ness – AEP, S1 Harold Wyble – KCP&L, S1 Robert Rhodes – SPP, S2	consequences may be basically the same. Response: The drafting team does not disagree that both violations can have reliability impacts. This is a judgment call, and the standard assumes that the lack of data can potentially halt the requestor's function whereas inconsistent/poor quality data will still allow some functionality on an appropriate basis.
John Blazekovich - Exelon, S1,S3,S5,S6	No. If a requirement is not important enough to include sanctions it should not be included in the Standards. Response: There are sanctions in the standard for methodology violations, but they are not financial in nature. The drafting team believes the penalties will be sufficient to incent the desired performance.
Raymond Mammarella – PPL, S1	Yes.
Carter Edge – S.E. Power Admin, S4, S5	Yes.
Alan Boesch – NPPD, S1	No. In section 601,602, 603,604, 605 and 606 the requirement is to document the methodology, include the criteria to not exceed ratings and include assumptions. The measurements should reflect the requirements and the levels of non-compliance should reflect the measures. Failure to provide the documentation within a prescribed time limit is a compliance issue that should be addressed by the compliance program. Response: The team agrees that the time limits are a compliance issue, to be handled via the compliance program. The NERC standards must specify the criteria to be used in the compliance process, as dictated by the NERC standards development manual, however. Requirements state the desired outcome; the time for accomplishing these outcomes is part of the measures. Measurements reflect the metrics used to measure compliance to the requirements, but are not a one-for-one translation of the requirements.
Tony Jankowski – We Energies, S4	Yes.
Don Chandler – CenterPoint, S1	Yes.
Tom Mielnik – MidAmerican, S3	Yes.
Michael Sidiropoulos – Pacificorp, S1	Yes.
Mitchell Needham – TVA, S1 Gary L. Jackson – TVA, S6 Mark Creech - TVA	Yes.
Mike Viles & 9 other employees – BPA Transmission, S1	Yes.
Carey Gates – CalISO, S2	No. Using a common methodology for determine all values is as important as determining the values and communicating them and should have financial

	penalties associated with it. Response: The majority of commenters do not support financial sanctions for methodology violations. During the drafting of the SAR associated with this standard, there was not consensus support for a single methodology.
Susan Morris – SERC, S2 Bill Reinke – SERC, S2 Sam Stryker – Fayetteville PWS, S3, S4, S5 John Stickley – AECI, S1 Carter Edge – SEPA, S4,S5 John Troha – SERC, S2 Tim Ponseti – TVA, S1 Bill Thompson – Dominion Transmission, S1	Yes.
Gerald Rheault – Manitoba Hydro, S1, S3, S5, S6	Yes.
Peter Burke – American Transmission Company, S1	Yes.
Kirit Shah – Ameren, S1	Yes.
WECC Technical Studies Subcommittee Peter Mackin – Trans Agency of Northern Calif, S1 Chifong Thomas – Pacific G&E, S1 Esteban Martinez – Turlock Irrigation District, S1 Peter Krzykos – Ariz Public Service, S1 Joe Seabrook – Puget Sound, A1 Phil Park – BC Trans Co, S1 C V Chung – Seattle City Light, S9	Yes. We agree with the progression of the penalties as described in section 601. However, there should be monetary penalties assessed for methodology violations, and these penalties should be less than the penalties for violations for failure to communicate values. If an entity has no methodology, then the rating values they supply to the Reliability Authority could be in error. These bad rating values could result in operation such that a contingency on the system could cause the element with the bad rating to fail (on top of the contingency), which could result in the potential for loss of load (when not called for) or cascading outages. Response: Availability of methodologies themselves does not *directly* impact the reliable operation of the transmission system. The unavailability of values will have a real and detrimental impact, though. This is the reason for the assignment of penalties the drafting team assumed. The majority of comments support this philosophy.
FRCC OC, EC, MIC Linda Campbell – FRCC, S2 Paul Elwing – Lakeland Electric, S3 John Shafer – FP&L, S1 Don McInnis – FP&L S1 Patti Metro – FRCC, S2 Joe Krupar – FMPA, S3 Richard Gilbert – Lakeland Elect S3 Amy Long – Lakeland Elect S1 Roger Westphal – Gainesville Regional Utilities S5 Bob Remley – Clay Elect Coop S4 Steve Wallace - Seminole Elect Coop S4 Ted Hobson – JEA, S1	No. Section 6, Sanctions should be removed completely from all of the standards. The compliance monitoring process and non-compliance levels are appropriate parts of the reliablility standard. However, the sanctions and penalties are part of the compliance program and are separate. The enforcement matrix should not be attached to this document, even for information only, as that gives the appearance of being part of the standard. The sanctions and penalties, along with the enforcement matrix are the responsibility of the new Compliance and Certification Committee (CCC). If the matrix is attached to the standard, every time the CCC changes it, the standard will need to be revised which is not something we should set ourselves up to do. Response: The inclusion of the referenced sections is required by the NERC standards development process manual. The drafting team cannot make the requested changes. FRCC is encouraged to submit this request to the Standards Authorization Committee.
Gary Won – IMO S2	No. Financial penalties should not be applied. This would open the gate to financial

	penalties for the many, much more severe violations addressed in other standards. The IMO feels that non-monetary sanctions are sufficient. Response: The drafting team respects this position. However, NERC reserves the right to levy financial sanctions, where appropriate, for violations of its standards. This comment will be shared with NERC's General Counsel and Director of Compliance.
William J Smith – Allegheny Power, Segment 1	Yes.
Guy Zito, **NPCC CP9** Michael Schiavone – Nat Grid USA, S1 Roger Champagne – HQ Transenergie, S1 Ralph Rufrano – NYPA, S1 David Little – Nova Scotia Power, S1 David Kiguel – Hydro One, S1 Michael Potishnak – ISONE, S2 Barry Gee, Nat Grid USA, S1 Dan Stosick – ISONE, S2 Fernando Saavedra – ISONE, S2 Greg Campoli – NYISO, S2	No. NPCC is adamantly opposed to monetary sanctions and feels letters of increasing severity are a more effective compliance tool for ensuring adherence to standards. Response: The drafting team respects this position. However, NERC reserves the right to levy financial sanctions, where appropriate, for violations of its standards. Such sanctions would be identified in the proposed standard and would be applied if the industry supported them. This comment will be shared with NERC's General Counsel and Director of Compliance.
Ken Githens – Allegheny Energy Supply – Segment 5	Yes.
Charles Yeung – Reliant Energy, S5	No. Lack of agreement and precision of transfer capabilities may have tremendous reliability implications. If this standard is to police transmission operators and RAs to calculate values that are to be employed for reliability, it must penalize those who do not provide realistic values. The only way to ensure all parties work together to develop good system limit values, is by having financial penalties for methodology violations. Penalizing only "failure to communicate" may already be covered under the Coordinate Operations Standard. Response: There are a multitude of reasons why transfer capability values may be in error. Failure to calculate them properly is one. However, the simple lack of a document does not automatically translate into incorrect values.
Kathleen Goodman – ISONE, S2	No. ISO-NE is adamantly opposed to monetary sanctions and believes letters of increasing severity are a more effective compliance tool for ensuring adherence to standards. Response: The drafting team respects this position. However, NERC reserves the right to levy financial sanctions, where appropriate, for violations of its standards. Such sanctions would be identified in the proposed standard and would be applied if the industry supported them. This comment will be shared with NERC's General Counsel and Director of Compliance.

6. **Do you agree with the proposed requirements and measurements in section 601? Do you agree with the proposed compliance monitoring process in section 601? Do you agree with the proposed levels of non-compliance in section 601?**

NERC Transmission Subcommittee	Requirements and Measurements – Agree Compliance Monitoring Process – Agree

Robert Reed – PJM Daniel Cooper – Michigan Public Power Agency Ken Donohoo – ERCOT Michael Gildea – Duke-Energy, North America Francis Halpin – BPA Tom Mallinger – MISO Darrick Moe – WAPA Scott Moore – AEP Bill Slater – Florida Power Corp Tom Stuchlik – Western Resources Joseph Styslinger – Southern Co David Thorne – DH Thorne Consultants Robert Waldele – NYISO Roman Carter – Southern Co John Ahr – Allegheny Power Susan Morris – SERC Ed Pfeiffer – Ameren Ray Palmieri – ECAR	Levels of Non-compliance – No response
Mark Heimbach – PPL Generation, Segment 5	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – No response
Roman Carter (& 9 other employees) - Southern Company Generation and Marketing, Segments 5,6 Terry Crawley & Roger Green – SOCO Generation, Segment 5	Requirements and Measurements – Agree However, the Standard should not require development of additional documentation unless existing documentation is inadequate for supporting the established rating. Additionally, the RA's need for a higher degree of accuracy on required data should not be necessary unless the current data does not fully meet modeling/assessment requirements. Response: The drafting team agrees and believes the standard is consistent with this comment. Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
R T Sikes (& 4 other employees) – CenterPoint Energy Real Time Operations	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Alan Johnson – Mirant Americas Energy Mktg, Segment 6	Requirements and Measurements – Agree Believe that the requirement should be for on-site inspection of methodology requirements. In other words, the TO's and GO's should not be required to provide copies of methodology documentation to the compliance monitor, RA or PA. Is this the intent here? Response: Yes, that is the intent. Also, in section 1.3, suggest that the list of equipment types be placed in a parenthetical to improve the sentence.

	Response: The drafting team agrees the sentence is clumsy, but after much deliberation, was unable to make improvements to it. Compliance Monitoring Process – No. Maybe okay with this section, depending on what is meant by the phrase "…information submittal to the compliance monitor". Are we talking about making documentation available to the compliance monitor for on-site inspection, or are we talking about providing copies of the methodology documentation to the compliance monitor? Opposed to the latter. Response:The intent is to make documentation available to the compliance monitor, but the use of on vs off-site inspection is up to the compliance monitor and will not be specified in the standard. Levels of Non-compliance – Agree
SERC Planning Standards Working Group Clay Young – South Carolina Electric & Gas, Segment 3 Byron Stewart – TVA, S1 David Weekly – Municipal Electric Authority of Georgia – S1 Brian Moss – Duke Power, S1 Darrell Pace – Alabama Electric Cooperative, S1 Bob Jones – SoCo, S1 Kham Vongkhamchanh – Entergy, S1 Pat Huntley – SERC, S2	Requirements and Measurements - No. 1. The standard should explicitly state that the methodology must be technically sound (i.e., should conform to good utility practice). Section 601.1.3 should be changed to stop with "…that comprise the facility are determined." A new section (601.1.4) should read: "**The methodology required in 601.1.1 shall be technically correct (conform to good utility practice) and reference industry rating practices or other standards (e.g., IEEE, ANSI, CSA).**" Response: The drafting team understands this point. The standard attempts to remain true to NERC's mission to develop standards aimed towards performance objectives as opposed to prescriptive "how to" rules. There is a SAR related to disturbance analysis that may serve as a useful feedback loop to measure the effectiveness of these standards. 7. The terms "disconnecting devices" in 601.1.3 should be changed to "terminal equipment" to encompass not only disconnecting devices, but also CTs, PTs, protection, wave traps, etc. as listed on page 5 of the SAR. Response: The change has been made as suggested. Compliance Monitoring Process – Agree Levels of Non-compliance – Agree. However, section 601.1.4 (proposed in our comment in question 6) should be incorporated into the Levels of Non-Compliance. Response: Please see prior response.
SERC Operations Planning Subcommittee Carter Edge – Southeastern Power Administration, S4&S5 William Gaither – South Carolina Public Service Auth, S1 Mike Miller – SoCo, S1 Roger Brand – Municipal Electric Authority of Georgia, S1	Same comments as SERC Planning Standards Working Group listed above.

Phil Creech – Progress Energy (Carolina), S1 Gene Delk & Al McMeekin – South Carolina Electric and Gas, S1 Greg Ott – Alcoa/Yadkin, S1 Doug Newbauer – Georgia System Operations, S1 Mike Clements & Mark Creech – TVA, S1 Don Reichenbach – Duke Energy, S1 Lynna Estep – SERC, S2	
Robert Grover – PPL, S3	Requirements and Measurements – Neither yes or no. The issue with this requirement is should this be a Standard or should it be included in the Certification requirements for an RA? As a Certification requirement, an applicant for RA certification would be required to have the methodology in-hand before the applicant was allowed to be an RA. As a standard the RA could operate without even having a method for computing limits. Response: In general, certification will only determine whether an entity is capable of performing a given function. This standard specifies what the entity performing the function must do. There is a need to include the methodologies in this standard to ensure that the most current version is being used for determining the limits and ratings. It is not clear at this time that all functions identified in this standard will be certified by NERC. However, please be aware that the RA function will not be responsible for determining equipment or facility ratings. Compliance Monitoring Process – Agree Levels of Non-compliance – No response
John Horakh – MAAC, S2	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
David Thorne – PEPCO, S1	Same comments as Robert Grover, PPL, above.
Todd Lucas & 5 other employees – SoCo Trans Plng, S1 and S3	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Lee Westbrook – OnCor, S1	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Darrel Richardson – Illinois Power, S1 S2	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Ed Davis – Entergy, S1	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
MAPP Operations Subcommittee Allan Silk – Manitoba Hydro Paul Brune – NPPD Paul Koskela – Minnesota Power Larry Larson – Otter Tail Darrick Moe – WAPA Dick Pursley – Great River Energy Martin Trence – Xcel Energy	Requirements and Measurements – No. Item 601.1.3 should explicitly include current tranformers, wavetraps, circuit breakers, switches, buswork, and relay load limits when listing equipment types. Response: This reference has been revised to include these types of equipment through the use of the term terminal equipment. It is not the intent of the standard to list every equipment type, but rather just the minimum level.

Todd Gosnell – Omaha PPD Joseph Knight – MAPPCOR, S2	Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Clay Young and 8 employees – South Carolina Electric & Gas, S1, S3, S5	Same comments as SERC Planning Standards Working Group listed above.
Paul Johnson – AEP, S1,S3,S5, S6	Requirements and Measurements – No. In Section 2.1 add Transmission Operators, for consistency with 602,604, and 606. The transmission Operator should be able to examine the Rating Methodology. Response: The suggested change has been made. Compliance Monitoring Process – Agree Levels of Non-compliance – No. In 601.5.4 (level 4) add Transmission Operator to the listing. Response: The suggested change has been made.
Dilip Mahendra – SMUD, S1	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
James Spearman & Florence Belser – PSC of S. Carolina, S9	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
SPP Operating Reliability WG Gerry Burrows – KCP&L, S1 Bob Cochran – SPS, S1 Peter Kuebeck – OG&E, S1 Scott Moore – AEP, S1 Dan Boezio – AEP, S1 Tom Stuchlik – Westar, S1 Matt Bordelon – CLECO, S1 Mike Crouch – WFEC, S1 Mike Gammon – KCP&L, S1 Kevin Goolsby – SPP, S2 Bo Jones – Westar, S1 Allen Klassen – Westar, S1 Thad Ness – AEP, S1 Harold Wyble – KCP&L, S1 Robert Rhodes – SPP, S2	Requirements and Measurements – No. The transmission operator should be allowed to review the rating methodology and therefore should be included in Measure 2.1. Response: The suggested change has been made. Compliance Monitoring Process – Agree Levels of Non-compliance – No. Sections 5.2 and 5.3 are very confusing. These non-compliance levels need to be clarified. The transmission operator needs to be included in Section 5.4. (See comment to Question 6.—listed above) Response: Transmission operator has been added. Sections 5.2 and 5.3 have been revised to added clarity.
John Blazekovich - Exelon, S1,S3,S5,S6	Requirements and Measurements – No. Section 601.1.2 states “facility ratings shall not exceed the applicable ratings of the individual equipment that comprises the facility”. This statement is in conflict with the “Purpose” statement in section 600 which states that facility ratings need only be adhered to in order to avoid “cascading outages, uncontrolled system separation, and voltage and transient instability”. This would allow an applicable rating of individual equipment to be exceeded resulting in thermal overloads or low voltage that does not result in a cascading outage, uncontrolled system separation, and voltage and transient instability. In order to correct this, the purpose statement in section 600 needs to be rewritten to also include thermal overloads and low

	voltage that do not result in cascading outages and instability. Response: The purpose statement has been revised in response to this, and other comments. Compliance Monitoring Process – No. Reset period should not be 1 year – non-compliance should reset as soon as methodology is deemed in compliance. Response: This suggestion will not increase compliance, but may rather encourage those non-compliant to delay correcting their deficiencies. A definition of reset-period has been included in the standard. Levels of Non-compliance – Agree.
Raymond Mammarella – PPL, S1	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Carter Edge – S.E. Power Admin, S4, S5	Same comments as SERC Planning Standards Working Group listed above.
Tom Pruitt & 4 other employees – Duke Power, S1 & S5	Requirements and Measurements - No. The standard should explicitly state that the methodology must be technically sound (i.e., should conform to good utility practice). Section 601.1.3 should be changed to stop with "…that comprise the facility are determined." A new section (601.1.4) should read: "**The methodology required in 601.1.1 shall be technically correct (conform to good utility practice) and reference industry rating practices or other standards (e.g., IEEE, ANSI, CSA).**" Response: The drafting team understands this point. The standard attempts to remain true to NERC's mission to develop standards aimed towards performance objectives as opposed to prescriptive "how to" rules. There is a SAR related to disturbance analysis that may serve as a useful feedback loop to measure the effectiveness of these standards. Compliance Monitoring Process – Agree Levels of Non-compliance – No. Section 601.5.1 should read: "Level one: The facility ratings methodology does not contain 601.1.2 or address one of the items listed in 601.1.3 **or does not meet 601.1.4 (is technically incorrect -- does not conform to good utility practice)."** Section 601.5.2.2 should read ". . . types listed in 601.1.3 **or meet 601.1.4**" Section 601.5.3.2 should read ". . . types listed in 601.1.3 **or meet 601.1.4**" Response: Please see response immediately above.
Alan Boesch – NPPD, S1	Requirements and Measurements – No. Compliance Monitoring Process – No. Levels of Non-compliance – No
Tony Jankowski – We Energies, S4	Requirements and Measurements – Agree Compliance Monitoring Process – No. 4.2.1 says self certify every 3 years. 4.3 compliance reset is 1 calendar year. Self

	certify should be every year. Response: The timeframes provided are minimum guidelines. Further guidance will be provided by the NERC compliance committee when they design their annual compliance review plans associated with this standard, assuming the standard is approved by the industry. Levels of Non-compliance – No. Should not have Level 3 or 4 if no financial penalties will be enforced. All should be Level 1 or 2. Response: Even though the different levels of non-compliance do not have financial penalties assigned to them in this case, the levels do have different type of non-compliance letters associated with them.
Don Chandler – CenterPoint, S1	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Tom Mielnik – MidAmerican, S3	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Michael Sidiropoulos – Pacificorp, S1	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Mitchell Needham – TVA, S1 Gary L. Jackson – TVA, S6 Mark Creech - TVA	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Mike Viles & 9 other employees – BPA Transmission, S1	Requirements and Measurements – Agree The transmission owner and generator owners are given sole responsibility for documenting the methodology for rating facilities in sections 601 and 602 of this standard. There are situations where the transmission operator or generator operator are in a better position to provide that information. Joint ownership of facilities is an example where that may be true. Response: Requirement 601.1 has been amended to address this comment. Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Carey Gates – CalISO, S2	Requirements and Measurements – Agree. In 601 2.1 the methodology used to determine values must be provided within 15 business days of request. We do not understand why it would take 15 days to provide a pre-established methodology. It could be a document that would be posted on a Transmission Owners website. We do not envision that the methodology would change very often once established. Response: The 15 business day requirement was included based upon the team's assumption for a reasonable amount of time to supply documentation that should be on file. The 15 days is intended to allow time for an entity to respond to a request considering the realities of staff availability and internal approval and communications processes. Certainly, posting the document on the web would be preferred, but it is not required in the standard. Compliance Monitoring Process – Agree

	Actually compliance verification by the compliance monitor at least once every ten years may be to long of a minimum period. Response: The timeframes provided are minimum guidelines. Further guidance will be provided by the NERC compliance committee when they design their annual compliance review plans associated with this standard, assuming the standard is approved by the industry. Levels of Non-compliance – Agree It would be helpful if a "table" illustrating the levels of non-compliance were added to this section. Response: The compliance committee will be asked to prepare an explanatory reference paper to be used with all standards.
Susan Morris – SERC, S2 Bill Reinke – SERC, S2 Sam Stryker – Fayetteville PWS, S3, S4, S5 John Stickley – AECI, S1 Carter Edge – SEPA, S4,S5 John Troha – SERC, S2 Tim Ponseti – TVA, S1 Bill Thompson – Dominion Transmission, S1	Same comments as SERC Planning Standards Working Group listed above.
Gerald Rheault – Manitoba Hydro, S1, S3, S5, S6	Requirements and Measurements – Agree Manitoba Hydro believes that item 601.1.3 should explicitly include current transformers, wave traps, circuit breakers, switches, bus work and relay load limits. Response: In response to this and other comments, the reference has been revised to include these types of equipment by inserting the term "terminal equipment". Compliance Monitoring Process – Agree The wording on the compliance monitoring process is perhaps too loose. For example in the wording in 601.4.1 (responsible entity shall demonstrate compliance to the compliance monitor within the first year) can be interpreted to mean that the entities will be required to show compliance within the first week or first month after the Standard comes into effect. Is this what was intended? Response: The actual start date and completion date will be identified in an implementation plan that will accompany the standard when it is balloted. A reasonable start date must be included, as suggested by this comment. Levels of Non-compliance – Agree The wording in 5.1 could be changed from "methodology does not contain 601.1.2 or address" to " methodology does not contain 601.1.2 or does not address" for clarity. Response: The suggested change has been made.
Peter Burke – American Transmission Company, S1	Requirements and Measurements – Agree

	Compliance Monitoring Process – Agree Please consider a 30 day period when records are requested. Fifteen days is really tight considering vacation schedules of responsible employees and other delays. Response: The 15 business day requirement was included based upon the team's assumption for a reasonable amount of time to supply documentation that should be on file. The 15 days is intended to allow time for an entity to respond to a request considering the realities of staff availability and internal approval and communications processes. Levels of Non-compliance – Agree
Kirit Shah – Ameren, S1	Requirements and Measurements – Agree 601.1.3 should include wave traps and relay limits. Response: In response to this and other comments, the reference has been revised to include these types of equipment by inserting the term "terminal equipment". Compliance Monitoring Process – No. Yes to all except 4.2.3- Which party can complain? Is it same as included in 602.4.3? If yes, include it in 601.4.2.3. Response: This section of each requirement has been revised in response to this comment. Levels of Non-compliance – Agree
WECC Technical Studies Subcommittee Peter Mackin – Trans Agency of Northern Calif, S1 Chifong Thomas – Pacific G&E, S1 Esteban Martinez – Turlock Irrigation District, S1 Peter Krzykos – Ariz Public Service, S1 Joe Seabrook – Puget Sound, S1 Phil Park – BC Trans Co, S1 C V Chung – Seattle City Light, S9	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree Please see comments to question 5. Response: The majority of comments do not appear to support financial sanctions for document violations.
FRCC OC, EC, MIC Linda Campbell – FRCC, S2 Paul Elwing – Lakeland Electric, S3 John Shafer – FP&L, S1 Don McInnis – FP&L S1 Patti Metro – FRCC, S2 Joe Krupar – FMPA, S3 Richard Gilbert – Lakeland Elect S3 Amy Long – Lakeland Elect S1 Roger Westphal – Gainesville Regional Utilities S5 Bob Remley – Clay Elect Coop S4 Steve Wallace - Seminole Elect Coop S4 Ted Hobson – JEA, S1	Requirements and Measurements – No. is confusing. The reference to 601.1.1 should be removed. 1.1 requires a document. It looks like 1.2 is trying to say that the methodology should ensure that facility ratings shall not exceed the ratings of individual components. The current wording says it shall "state" that faciltiy ratings.., but just to "state" it does not really mean anything. We would suggest to rewrite the 1.2 as follows - The methodolgy shall ensure that facility ratings shall not exceed the applicable ratings of the individual equipment that comprises the facility. Response: The referenced requirement requires that the methodology expressly state that facility ratings shall not exceed the ratings of individual comments. A methodology cannot ensure, but rather state what must be done. 1.3 also seems to be unclear about the method or the documentation. It appears

	reading the requirement that it is really trying to state that the documentation needs to make sure and cover many listed. We would recommend that 1.3 be reworded to this - "The documentation shall identify.." rather than the methodology required in 601.1.1 Response: The drafting team considered the suggested changes and believes the original wording more appropriately conveys the desired intent. Similar confusion exists in 2.1. We recommend that 2.1 be reworded to state- "The documentation shall be made available.." Also, in this statement remove compliance monitor. The compliance monitor notification should only be part of the compliance monitoring process. The important part of this measure is that the documentation is made available to those that need to review it such as the RA and PA. Response: The drafting team considered the suggested changes and believes the original wording more appropriately conveys the desired intent. 2.2 also needs to be clarified. It currently states that the documentation shall contain all items listed in 1.2 and 1.3, but 1.3 is requiring identification of assumptions used for different equipment types. So, in 2.2 why would the measure require all items in 1.3? Response: The intent of 1.3 is to require that the listed equipment types are included, at a minimum. The metric used in 2.2 describes how compliance to the requirements will be measured. An observation we have made is that it appears that this new standard is replacing the existing NERC Planning standards IA, IE, IIB, and IIC. These planning standards were very specific and included much more detail. Requirement 1.1 mentions generators, but yet there is very little detail about what is required of them. Will this standard replace the 4 planning standards that we have mentioned? Response: This standard will replace portions of the listed standards, but may not replace them all. Compliance Monitoring Process – No. In 4.1 the entity is required to provide information, but it does not say within a number of business days of a request. Should there be a time frame to comply? Also, it states that submittal shall be either on or off site. Does the compliance monitor determine if it will be submitted off site (via mail) or on site (on site visit)? Response: These details will be left to the compliance monitor who must develop a detailed compliance review plan. The standard provides a high level overview of the compliance process. In 4.3 the peformance reset period is listed as 1 year. How does this relate to the self certification requirement of every 3 years? We are not certain what the reset period really means when various parts of the compliance monitoring process have different time frames for reporting. Response: A definition of compliance-reset period has been included in the standard in response to this and other comments. Levels of Non-compliance – No. 5.1 has words about not containing 601.1.2 or addressing 601.1.3. We do not think contain is appropriate based on our comments on requirement 1.2. It seems like

	both 1.2 and 1.3 shoud be addressed in the methodology. If a facility owner does not own one of the types listed in 1.3, does it mean they are non-compliant? 5.2 builds on 5.1 so if it is changed, 5.2 needs to be revised as well and the same for 5.3 and 5.4. Response: 1.3 only applies to the equipment that is owned by an entity.
Gary Won – IMO S2	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree See general comment below. Response: The general comment is addressed as part of sections 12-13.
William J Smith – Allegheny Power, Segment 1	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Guy Zito, **NPCC CP9** Michael Schiavone – Nat Grid USA, S1 Roger Champagne – HQ Transenergie, S1 Ralph Rufrano – NYPA, S1 David Little – Nova Scotia Power, S1 David Kiguel – Hydro One, S1 Michael Potishnak – ISONE, S2 Barry Gee, Nat Grid USA, S1 Dan Stosick – ISONE, S2 Fernando Saavedra – ISONE, S2 Greg Campoli – NYISO, S2	Requirements and Measurements – Agree NPCC suggests defining the term "applicable rating" as it appears in 601 Requirement, Section 1.2. Response: Ratings will depend upon the timeframe, system condition, season, etc. This is what is intended by 'applicable rating'. NPCC feels 15 business days is an insufficient time to submit data and requests it be changed to at least 20 business days. Response: The 15 business day requirement was included based upon the team's assumption for a reasonable amount of time to supply documentation that should be on file. The 15 days is intended to allow time for an entity to respond to a request considering the realities of staff availability and internal approval and communications processes. Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Ken Githens – Allegheny Energy Supply – Segment 5	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Charles Yeung – Reliant Energy, S5	Requirements and Measurements – No. Requirement 1.1.3 should require that a transmission owner or generator owner identify the lowest rated equipment installed within a facility if a particular piece of equipment (such as a carrier wave trap or a line switch) is the limiting element that is preventing a higher facility rating. NERC should be aware of such conditions to identify areas of the grid that can be upgraded with relative ease. Response: This goes beyond the scope in the SAR. The intent of the standard is not to optimize transmission expansion. Compliance Monitoring Process – No. There does not appear to be any obligation for facility owners to rerate their facilities in the event of equipment changes. NERC's information should be kept up to date and a compliance measure should be created to address this. Additionally, the Transfer Capability numbers are highly dependent upon the facility ratings and these numbers should be revised when the Facility Ratings are changed. Response: 602.2.2 and 602.5.2 address the need to re-rate existing equipment and to communicate the revised ratings. The drafting team feels this sufficiently addresses this comment.

	Levels of Non-compliance – No Response.
Kathleen Goodman – ISONE, S2	Requirements and Measurements – Agree and Disagree. ISO-NE suggests defining the term "applicable rating" as it appears in 601 Requirement, Section 1.2. Response: Ratings will depend upon the timeframe, system condition, season, etc. This is what is intended by 'applicable rating'. ISO-NE believes that 15 business days is an insufficient time to submit data and requests it be changed to at least 20 business days. Response: The 15 business day requirement was included based upon the team's assumption for a reasonable amount of time to supply documentation that should be on file. The 15 days is intended to allow time for an entity to respond to a request considering the realities of staff availability and internal approval and communications processes. Compliance Monitoring Process – Agree Levels of Non-compliance – Agree

7. **Do you agree with the proposed requirements and measurements in section 602? Do you agree with the proposed compliance monitoring process in section 602? Do you agree with the proposed levels of non-compliance in section 602?**

NERC Transmission Subcommittee Robert Reed – PJM Daniel Cooper – Michigan Public Power Agency Ken Donohoo – ERCOT Michael Gildea – Duke-Energy, North America Francis Halpin – BPA Tom Mallinger – MISO Darrick Moe – WAPA Scott Moore – AEP Bill Slater – Florida Power Corp Tom Stuchlik – Western Resources Joseph Styslinger – Southern Co David Thorne – DH Thorne Consultants Robert Waldele – NYISO Roman Carter – Southern Co John Ahr – Allegheny Power Susan Morris – SERC Ed Pfeiffer – Ameren Ray Palmieri – ECAR	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – No response
Mark Heimbach – PPL Generation, Segment 5	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Roman Carter (& 9 other employees) - Southern Company Generation and Marketing, Segments 5,6	Requirements and Measurements – Agree However, under 602 2.2.2, it is believed the RA, PA, and TOP need to allow for the

Terry Crawley & Roger Green – SOCO Generation, Segment 5	facility owner's input so an achievable schedule is established. For example when generator data is requested and many generators are involved, or when generating plant calculations and engineering studies are required. Response: The drafting team agrees that schedules need to allow sufficient time to develop ratings; however, the schedule must be driven by the RA, PA or TOP's need date for the information. Issuing an "unreasonable" schedule only promotes poor quality data and defeats the end objective. The standard does not attempt to establish the parameters for measuring an "achievable" schedule but leaves it to the involved parties. Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
R T Sikes (& 4 other employees) – CenterPoint Energy Real Time Operations	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Alan Johnson – Mirant Americas Energy Mktg, Segment 6	Requirements and Measurements – Agree In section 1.2, suggest that a phrase such as "upon request" or "in accordance with their published schedules" be tacked on to the end of the sentence. This will serves to provide some clarity regarding the obligation. Along the same lines, would suggest adding a phrase such as "as documented in procedures" to the end of the sentence in section 2.2. Response: Additional words were not put in section 1.2 because they would change the fundamental obligation into a Measure. Although having a schedule formalized is desirable, it is the intent of this standard to allow for any workable communication between entities. Compliance Monitoring Process – Agree For clarity, suggest inserting " applicable" between "the" and "reliability" in the first part of section 4.3 Response: Section 4.3 has been revised to add greater clarity. Levels of Non-compliance – Agree
SERC Planning Standards Working Group Clay Young – South Carolina Electric & Gas, Segment 3 Byron Stewart – TVA, S1 David Weekly – Municipal Electric Authority of Georgia – S1 Brian Moss – Duke Power, S1 Darrell Pace – Alabama Electric Cooperative, S1 Bob Jones – SoCo, S1 Kham Vongkhamchanh – Entergy, S1 Pat Huntley – SERC, S2	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
SERC Operations Planning Subcommittee Carter Edge – Southeastern Power	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree

Administration, S4&S5 William Gaither – South Carolina Public Service Auth, S1 Mike Miller – SoCo, S1 Roger Brand – Municipal Electric Authority of Georgia, S1 Phil Creech – Progress Energy (Carolina), S1 Gene Delk & Al McMeekin – South Carolina Electric and Gas, S1 Greg Ott – Alcoa/Yadkin, S1 Doug Newbauer – Georgia System Operations, S1 Mike Clements & Mark Creech – TVA, S1 Don Reichenbach – Duke Energy, S1 Lynna Estep – SERC, S2	
Robert Grover – PPL, S3	Requirements and Measurements – Agree Compliance Monitoring Process – Neither yes or no Will Compliance Monitors really look at how rating computations relate to the documented methodology? Response: It is expected that this will occur, since such monitoring is performed today by referencing a sample of key facilities. Levels of Non-compliance – Neither yes or no
John Horakh – MAAC, S2	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Will Compliance Monitors really look at how rating computations relate to the documented methodology? Response: It is expected that this will occur, since such monitoring is performed today by referencing a sample of key facilities. Levels of Non-compliance – Agree
David Thorne – PEPCO, S1	Same comments as Robert Grover, PPL, above. Response: Please see response to Robert Grover above.
Todd Lucas & 5 other employees – SoCo Trans Plng, S1 and S3	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree In 602 5.2., the phrase “upon request” should be removed. The measures require that the information be provided on a schedule. Having “upon request” and “with their respective schedules” in the same sentence is ambiguous. Response: “Upon request” has been removed.
Lee Westbrook – OnCor, S1	Requirements and Measurements – Agree

	Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Darrel Richardson – Illinois Power, S1 S2	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – No. There should not be any difference between a new facility or an existing facility. Levels #1 & #2 (5.1 & 5.2) should be combined and have only 3 levels of non-compliance. Response: Providing data for existing facilities is usually on a repeat basis. Missing data can possibly be obtained/approximated from the mass of previously supplied data. New facilities can be quite different from previously installed facilities or is simply unknown to the requestor and cannot even be approximated – thereby making it more serious.
Ed Davis – Entergy, S1	Requirements and Measurements – No. The establishment and communication of facility ratings to all functions that will need those ratings is good. In particular, the ratings must be sent to the Transmission Service Provider, in addition to the RA, TOP and transmission planning section of the PA. The FERC regulated TSP will use the ratings to determine Available Transfer Capability (per the Functional Model) and TTC. In addition, the TSP is required by FERC to sign a Code of Conduct and is a Service Function per the Model, so there should be no objection to the TSP having this information. Response: According to the NERC Function Model, the Transmission Service Provider (TSP) function "provides transmission services to qualified market participants under applicable transmission service agreements." Among other things, the TSP function accepts reservation requests via the OASIS and processes each request for service. The TSP function receives the SOLs and TCs determined by the RA and TOP functions (and for future transactions by the PA function) to establish ATCs for the OASIS and to administer the applicable service agreements. As such, the TSP function does not determine the SOLs or TCs, and therefore would have no use for facility ratings, which are used to determine these quantities. Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
MAPP Operations Subcommittee Allan Silk – Manitoba Hydro Paul Brune – NPPD Paul Koskela – Minnesota Power Larry Larson – Otter Tail Darrick Moe – WAPA Dick Pursley – Great River Energy Martin Trence – Xcel Energy Todd Gosnell – Omaha PPD Joseph Knight – MAPPCOR, S2	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Clay Young and 8 employees – South Carolina Electric & Gas, S1, S3, S5	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Paul Johnson – AEP, S1,S3,S5, S6	Requirements and Measurements – Agree Compliance Monitoring Process – No.

	602.4.1 requires self certification at least every three years and 602.4.2 requires annual verification that the data has been received by the Reliability Authority et.al. These activities appear redundant. Recommend deletion of 602.4.1. Response: 602.4.1 monitors consistency of rating development whereas 602.4.2 monitors communication of ratings to those needing the information. Levels of Non-compliance – Agree.
Dilip Mahendra – SMUD, S1	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
James Spearman & Florence Belser – PSC of S. Carolina, S9	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
SPP Operating Reliability WG Gerry Burrows – KCP&L, S1 Bob Cochran – SPS, S1 Peter Kuebeck – OG&E, S1 Scott Moore – AEP, S1 Dan Boezio – AEP, S1 Tom Stuchlik – Westar, S1 Matt Bordelon – CLECO, S1 Mike Crouch – WFEC, S1 Mike Gammon – KCP&L, S1 Kevin Goolsby – SPP, S2 Bo Jones – Westar, S1 Allen Klassen – Westar, S1 Thad Ness – AEP, S1 Harold Wyble – KCP&L, S1 Robert Rhodes – SPP, S2	Requirements and Measurements – Agree. Compliance Monitoring Process – No. The difference between what's required in Sections 4.1 and 4.2 is not clear. Why not just delete 4.1 and go with annual verification? Response: 602.4.1 monitors consistency of rating development whereas 602.4.2 monitors communication of ratings to those needing the information. Levels of Non-compliance – No. There is a lack of consistency in the levels of non-compliance between 601 and 602. There are monetary penalties in 602.6 for not communicating ratings in 602.6, but there are no monetary penalties for not having ratings at all in 601.6. Response: 601.6 addresses the need for a formalized methodology document(s); 602.6 addresses communication of ratings, without which the requestor may not be able to perform his function. The standard's philosophy, which has been supported by most commenters, is that methodology violations are not as severe as those related to a lack of ratings themselves.
John Blazekovich - Exelon, S1,S3,S5,S6	Requirements and Measurements – No. The requirement should read as follows: The transmission owner and generator owner shall establish facility ratings for their electric facilities ***consistent with the ratings methodology described in section 601.1***. This change results in the requirement being consistent with the measurement (602.2.1). Response: Additional words were not put in section 602.1.1 because they would change the fundamental obligation into a measure. Compliance Monitoring Process – Agree Levels of Non-compliance – No. We feel that inconsistent methodology should be the most severe level of noncompliance (level 4) Response: This is a judgment call, but the standard assumes that the lack of rating data can potentially halt the requestor's function whereas inconsistent/poor quality data will still allow some functioning on an appropriate basis.

Raymond Mammarella – PPL, S1	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Carter Edge – S.E. Power Admin, S4, S5	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Tom Pruitt & 4 other employees – Duke Power, S1 & S5	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Alan Boesch – NPPD, S1	Requirements and Measurements – No. Compliance Monitoring Process – No. Levels of Non-compliance – No
Tony Jankowski – We Energies, S4	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – No. See response to 601. If no financial penalties. Should not have compliance measures that go into financial penalty area of matrix. Response: This requirement will assign financial penalties for non-compliance, consistent with the level of the violation. This philosophy has been supported by most commenters.
Don Chandler – CenterPoint, S1	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Tom Mielnik – MidAmerican, S3	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Michael Sidiropoulos – Pacificorp, S1	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Mitchell Needham – TVA, S1 Gary L. Jackson – TVA, S6 Mark Creech - TVA	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Mike Viles & 9 other employees – BPA Transmission, S1	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Suggest switching 4.1 and 4.2 so the more frequent response is listed first. Response: This comment does not change the intent of the standard and makes logical sense. The change has been made. Levels of Non-compliance – Agree
Carey Gates – CalISO, S2	Requirements and Measurements – Agree Section 602 2.2 requires the responsible entity to provide facility ratings to the RA, PA and TO on a schedule established by the RA, PA or TO. This will lead to many varying schedules and may become confusing. Maybe the values need to be communicated initially and then by exception each time a change is made or a new facility is added.

	Response: Varying schedules will be inevitable due to changing system and organizational conditions. The actual procedure for providing data will be agreed upon by the involved parties. The drafting team agrees that schedules need to allow sufficient time to develop ratings; however, the schedule must be driven by the RA, PA or TOP's need date for the information. Issuing an "unreasonable" schedule only promotes poor quality data and defeats the end objective. The standard does not attempt to establish the parameters for measuring an "achievable" schedule but leaves it to the involved parties. Compliance Monitoring Process – Agree Levels of Non-compliance – Agree It would be helpful if a "table" illustrating the levels of non-compliance were added to this section. Response: The compliance committee will be asked to develop an explanatory reference paper to be used with all standards.
Susan Morris – SERC, S2 Bill Reinke – SERC, S2 Sam Stryker – Fayetteville PWS, S3, S4, S5 John Stickley – AECI, S1 Carter Edge – SEPA, S4,S5 John Troha – SERC, S2 Tim Ponseti – TVA, S1 Bill Thompson – Dominion Transmission, S1	Requirements and Measurements – No. The "Transmission Service Provider" should be added to the RA, PA, and TOP in 602 sections 1.2 and 2.2. Response: According to the NERC Function Model (January 20, 2002), the Transmission Service Provider (TSP) function "provides transmission services to qualified market participants under applicable transmission service agreements." Among other things, the TSP function accepts reservation requests via the OASIS and processes each request for service. The TSP function receives the SOLs and TCs determined by the RA and TOP functions (and for future transactions by the PA function) to establish ATCs for the OASIS and to administer the applicable service agreements. As such, the TSP function does not determine the SOLs or TCs, and therefore would have no use for facility ratings, which are used to determine these quantities. Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Gerald Rheault – Manitoba Hydro, S1, S3, S5, S6	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree The wording in 5.1 could be changed from "methodology does not contain 601.1.2 or address" to " methodology does not contain 601.1.2 or does not address" for clarity. Response: It appears this comment was intended for Requirement 601. This change was made, as suggested.
Peter Burke – American Transmission Company, S1	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Kirit Shah – Ameren, S1	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
WECC Technical Studies Subcommittee	Requirements and Measurements – Agree Compliance Monitoring Process – Agree

Peter Mackin – Trans Agency of Northern Calif, S1 Chifong Thomas – Pacific G&E, S1 Esteban Martinez – Turlock Irrigation District, S1 Peter Krzykos – Ariz Public Service, S1 Joe Seabrook – Puget Sound, A1 Phil Park – BC Trans Co, S1 C V Chung – Seattle City Light, S9	Levels of Non-compliance – Agree Some clarification/explanation is needed. For example, why are ratings of new facilities (Level 2) more important than levels of existing facilities (Level 1)? Why is not providing a rating for one new facility (Level 2) worse than not providing some existing ratings (Level 1)? Why is one rating not developed consistent with the ratings methodology (Level 3) worse than no existing ratings being provided (Level 1)? There is no distinction between missing between one rating and most of the ratings. This is a disincentive for people to improve compliance. Response: The drafting team discussed the possibility of enhancing the levels of non-compliance by factoring in the percentage of data not provided; however, it was felt that the complexity that would be added was not warranted. The levels were established on practical considerations of whether the requestor could continue to perform his functions properly. Missing existing data was level 1 since such data could be appropriated from the mass of past data. New missing data is level 2 since unknown configurations may exist that warp efforts to approximate data. Inconsistency is level 3 since erroneous actions can be taken due to such unknowns.
FRCC OC, EC, MIC Linda Campbell – FRCC, S2 Paul Elwing – Lakeland Electric, S3 John Shafer – FP&L, S1 Don McInnis – FP&L S1 Patti Metro – FRCC, S2 Joe Krupar – FMPA, S3 Richard Gilbert – Lakeland Elect S3 Amy Long – Lakeland Elect S1 Roger Westphal – Gainesville Regional Utilities S5 Bob Remley – Clay Elect Coop S4 Steve Wallace - Seminole Elect Coop S4 Ted Hobson – JEA, S1	Requirements and Measurements – Agree However, in 2.1 and 2.2 if references "responsible entities". The standard language needs to be more specific as to who this applies to. Response: This was discussed with NERC's General Counsel and his opinion was that the use of responsible entities was clear and legally sufficient. The alternative of repeating each entity in each passage would make the standard difficult to follow. Compliance Monitoring Process – No. Same comment about on or off site that we stated in question 7. In 4.4 the performance reset period of 1 years appears to be ok with 4.2, but 4.1 is on a 3 year cycle. We are not sure we understand what this really means. Response: The use of on or off site investigations will be left to the compliance monitor and not specified in the standard. A definition of performance-reset period has been included in the standard in response to this and other comments. 4.1 sets a maximum time period. In general, when non-compliance is found, compliance monitor follow-up to ensure corrective action was taken should occur before the reset period expires. This is a compliance implementation issue. Levels of Non-compliance – No. 5.1 is based on getting ratings for existing facilities and 5.2 is for new or modified facilities. Why would non compliance for existing be less of a violation than for new? We are not sure we understand the reasoning here. Response: Providing data for existing facilities is usually on a repeat basis. Missing data can possibly be obtained/approximated from the mass of previously supplied data. New facilities can be quite different from previously installed facilities or is simply unknown to the requestor and cannot even be approximated – thereby making it more serious.
Gary Won – IMO S2	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – No. The levels do not seem to follow any progression which would suggest increasing severity. Why is failure to have all ratings for existing facilities any different than not having all ratings for new facilities: level 1 as opposed to level 2? Either you have

	ratings or not. Response: Providing data for existing facilities is usually on a repeat basis. Missing data can possibly be obtained/approximated from the mass of previously supplied data. New facilities can be quite different from previously installed facilities or is simply unknown to the requestor and cannot even be approximated – thereby making it more serious.
William J Smith – Allegheny Power, Segment 1	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Guy Zito, **NPCC CP9** Michael Schiavone – Nat Grid USA, S1 Roger Champagne – HQ Transenergie, S1 Ralph Rufrano – NYPA, S1 David Little – Nova Scotia Power, S1 David Kiguel – Hydro One, S1 Michael Potishnak – ISONE, S2 Barry Gee, Nat Grid USA, S1 Dan Stosick – ISONE, S2 Fernando Saavedra – ISONE, S2 Greg Campoli – NYISO, S2	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Ken Githens – Allegheny Energy Supply – Segment 5	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Kathleen Goodman – ISONE, S2	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree

8. **Do you agree with the proposed requirements and measurements in section 603? Do you agree with the proposed compliance monitoring process in section 603? Do you agree with the proposed levels of non-compliance in section 603?**

NERC Transmission Subcommittee Robert Reed – PJM Daniel Cooper – Michigan Public Power Agency Ken Donohoo – ERCOT Michael Gildea – Duke-Energy, North America Francis Halpin – BPA Tom Mallinger – MISO Darrick Moe – WAPA Scott Moore – AEP Bill Slater – Florida Power Corp Tom Stuchlik – Western Resources Joseph Styslinger – Southern Co David Thorne – DH Thorne Consultants Robert Waldele – NYISO Roman Carter – Southern Co	Requirements and Measurements – No. 1) The TS recommends enhancing the cell in Table 1 "A – No Contingencies , and "Contingencies" that currently reads "All Facilities in Service." Instead of "all" the TS suggests language that reflects "scheduled" or "anticipated." 2) Footnote b) needs to be enhanced. Recommendations are to break the first sentence into two or more sentences and ensure the footnote b) language is concise, clear, and direct. Response: The table section has been modified to clarify the intent and correct any errors, in response to this and other comments. Levels of Non-compliance – No response

John Ahr – Allegheny Power Susan Morris – SERC Ed Pfeiffer – Ameren Ray Palmieri – ECAR	
Mark Heimbach – PPL Generation, Segment 5	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Roman Carter (& 9 other employees) - Southern Company Generation and Marketing, Segments 5,6 Terry Crawley & Roger Green – SOCO Generation, Segment 5	Requirements and Measurements – No. Under 603 1.1.1, The Transmission Owner should be added to the entities required to document the methodology used for determining system operating limits. Response: According to the functional model, the Transmission Owner has no responsibility for system operating limits. The Transmission Owner may have an interest in the methodology as it may impact on compliance with facility and equipment limits. The Reliability Authority may delegate some functions to others. This appears to relate to the difficulty of keeping clear distinction between "functions" and "entities". Various Regions and Authorities may organize differently to ensure each function is performed. Also, under Table I in section 1.3.1, it is recommended that the wording "All facilities in service" be replaced with "scheduled facilities in service" to eliminate any confusion that under normal operating conditions not all facilities would be in service. Finally, under the same table I, clarification of footnote (b) is needed to clear up confusion. The first sentence of the footnote is nearly 3 lines long and leads some people to be unsure about the meaning. Response: The table section has been modified to clarify the intent and correct any errors, in response to this and other comments. Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
R T Sikes (& 4 other employees) – CenterPoint Energy Real Time Operations	Requirements and Measurements – Agree Compliance Monitoring Process – Yes and No. We are not clear on ratings versus limits. Some possible clarification would be helpful. Response: The difference is that equipment ratings are one of several inputs into operational limits. For example, an operational limit on a facility may take voltage or stability constraints imposed by the network into consideration, as well as the rating of the equipment. Levels of Non-compliance – Agree
Alan Johnson – Mirant Americas Energy Mktg, Segment 6	Requirements and Measurements – Agree Compliance Monitoring Process – Agree. Levels of Non-compliance – No. This may be okay with some language changes.

	• Suggest revising section 5.1 to read: " Level one: The system operating limits methodology does not yield system operating limits in compliance with Table I or in the case of NPCC entities, Table IA." Response: The drafting team understands this point. The standard attempts to remain true to NERC's mission to develop standards aimed towards performance objectives that are measurable by an auditor. There is a SAR related to disturbance analysis that may serve useful as a feedback loop to measure the effectiveness of these standards. • Suggest revising section 5.2 to read: " Level two: The system operating limits methodology does not comply with section 603.1.2" Response: The Standard drafting team believes that the effect of this wording and your proposal is identical, so the change was not made. • Suggest revising section 5.3 to read: "Level three: The system operating limits methodology i) does not yield system operating limits in compliance with Table I or in the case of NPCC entities, Table IA; or ii) does not comply with section 603.1.2; and iii) does not contain any two items listed in section 603.1.4. Response: The Standard drafting team believes that the effect of this wording and part of your proposal is identical.
SERC Planning Standards Working Group Clay Young – South Carolina Electric & Gas, Segment 3 Byron Stewart – TVA, S1 David Weekly – Municipal Electric Authority of Georgia – S1 Brian Moss – Duke Power, S1 Darrell Pace – Alabama Electric Cooperative, S1 Bob Jones – SoCo, S1 Kham Vongkhamchanh – Entergy, S1 Pat Huntley – SERC, S2	Requirements and Measurements – No. Wording needs to be included that the level of performance specified is a minimum and that more stringent criteria for individual transmission providers or regions are permissible. Many of the Transmission Providers in SERC plan beyond N-1 criteria. The PSWG feels that adherence to 603 as written without this wording will result in reduced reliability in the SERC region. Response: The NERC requirement is intended as a minimum and Regions do have the right to use more stringent requirements if they choose. These requirements need not be included in the NERC standard if the Region does not wish for NERC to enforce them in that Region. Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
SERC Operations Planning Subcommittee Carter Edge – Southeastern Power Administration, S4&S5 William Gaither – South Carolina Public Service Auth, S1 Mike Miller – SoCo, S1 Roger Brand – Municipal Electric Authority of Georgia, S1 Phil Creech – Progress Energy (Carolina), S1 Gene Delk & Al McMeekin – South Carolina Electric and Gas, S1 Greg Ott – Alcoa/Yadkin, S1 Doug Newbauer – Georgia System Operations, S1	Same comments as SERC Planning Standards Working Group listed above.

Mike Clements & Mark Creech – TVA, S1 Don Reichenbach – Duke Energy, S1 Lynna Estep – SERC, S2	
Robert Grover – PPL, S3	Requirements and Measurements – Agree Regarding the Functional Model, Transmission Operators really can not be held responsible for "System" limits, they can be held responsible for local limits. Response: Agreed. That is the meaning of the phrase "for the areas for which they are responsible". Compliance Monitoring Process – Agree Levels of Non-compliance – No response
John Horakh – MAAC, S2	Requirements and Measurements – Agree Does this allow that the methodology used by the RA can be different than the methodology used by the PA? Response: The standard allows the RA and PA functions to employ different methodologies. However, practicality will dictate that the same or compatible methodologies be employed for associated RAs and PAs. Regarding the Functional Model, Transmission Operators really can not be held responsible for "System" limits, they can be held responsible for local limits. Response: Agreed, that is the meaning of the phrase "for the areas for which they are responsible". Compliance Monitoring Process – Agree Note d) on Page 7 does not make sense for Single Pole Block. The Cascading Outages Column on Page 9 has note f), should be note c). Note f) not needed. Response: The table section has been modified to clarify the intent and correct any errors, in response to this and other comments. Levels of Non-compliance – Agree
David Thorne – PEPCO, S1	Same comments as Robert Grover, PPL, above.
Todd Lucas & 5 other employees – SoCo Trans Plng, S1 and S3	Requirements and Measurements – No. The phrase "for the areas for which they are responsible" appears several times. We assume this is a reference to the functional model responsibilities. We believe it would be helpful if these areas of responsibility were re-stated in this standard, making it clear what these areas are for each entity. We also believe that it should be stated that the level of performance specified is a minimum and that more stringent criteria for individual transmission providers or regions are permissible. Response: This is a good point. When all the NERC standards are completed, the functional model should be attached to them as a reference document. The drafting team does not believe it is appropriate to repeat the functional model in every standard. In general, NERC standards are high level, minimum requirements necessary for the reliability of the bulk electric systems.

	Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Lee Westbrook – OnCor, S1	Requirements and Measurements – Agree A footnote should be added to Table I stating that the use of a Special Protection System or a Remedial Action Plan is an acceptable practice to meet the system performance requirements of Table I. Response: The table section has been modified to clarify the intent and correct any errors, in response to this and other comments. Additionally, section 603.1.4.3 refers to the use of Special Protection Systems and Remedial Action Schemes - such systems are acceptable but the methodology must describe how these systems are treated in determining system limits. Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Darrel Richardson – Illinois Power, S1 S2	Requirements and Measurements – No. Their needs to be more clarification. The table and subscripts are confusing. For example, we can't ascertain whether the "single pole block" is addressing DC lines or multiple circuit towers. Response: The table section has been modified to clarify the intent and correct any errors, in response to this and other comments. Compliance Monitoring Process – Agree Levels of Non-compliance – No. This section also seems to be difficult to follow. However, it would appear to us that a Level 1 should be for 603.1.4, Level 2 for 603.1.3 and Level 3 for 603.1.2 or some combination thereof. Response: The general rationale for levels of non-compliance was provided in the introductory material on the feedback form. This suggestion places prevention of equipment damage at a higher priority that avoidance of serious system problems. Further industry feedback on this issue would be beneficial.
Ed Davis – Entergy, S1	Requirements and Measurements – No. We believe the Transmission Owner has the ultimate responsibility to establish equipment operating limits which is a result of its fiduciary responsibility for its owned facilities. The Transmission Owner has ultimate responsibility and liability for owning, maintaining and operating its facilities to protect its stockholders' and lending institutions' investments. The Transmission Owner, then, is ultimately responsible for establishing system operating limits based on thermal ratings. While the Transmission Owner may voluntarily contract to have some other entity (function) perform some of the operations needed to ensure that fiduciary

	responsibility, it is the Transmission Owner that has ultimate responsibility. Neither NERC standards nor the Functional Model can allocate or transfer that responsibility to the RAs. Under state law, Transmission Owners must typically obtain state regulatory approval to transfer control or operational authority over jurisdictional facilities to third parties. Forcing Transmission Owners to allow a third party, such as the RA, to cede ultimate responsibility for establishing system limits could trigger the need for state regulatory approvals. However, the Transmission Owners may voluntarily contract some functional responsibilities to other entities, like the RA, TOP, and TSP, but the ultimate responsibility would still reside with the Transmission Owner. System operating limits (and interconnection reliability operating limits) are the lesser of the thermal, stability and voltage limits. The determination of each of these limits resides with different entities (functions). Equipment thermal limits and the thermal-based value of Tv for that equipment are the responsibility of the Transmission Owners. (For instance, a Transmission Owner might have dynamic thermal line ratings on specific transmission lines which are the responsibility of the TO.) Stability limits and associated value of Tv are the responsibility of the RA in the operating horizon and the PA in the planning horizon. Voltage limits are a responsibility shared by all three entities (functions). Therefore, we believe it is incorrect to say that any one entity (function) has ultimate responsibility to establish system operating limits. We also believe it is incorrect to say that any one entity (function) has ultimate responsibility to establish Interconnection Reliability Operating Limits. We suggest the above reasoning be used to revise this standard, the Operate Within IROL standard, and all other standards. Response: The standard recognizes the right of those performing the facility owner function to determine the appropriate ratings for their facilities. The standard also requires that system operating limits respect the facility ratings. The standard does not require that owners cede their right to establish facility ratings to any third party. System operating limit determination requires wider-area information that the facility owner may not have. Please add TOs and TSPs to the requirements 603 section 1.1 for documenting the methodology used for determining system operating limits, as the draft standard only indicates RAs, PAs, and TOPs. Response: According to the functional model, the Transmission Owner and Transmission Service Provider have no responsibility for system operating limits. The requirements of 603 section 1.3 should be modified to include the following statement: “Table I contains a minimum level of performance. Some Transmission Owners and or regions plan for operations beyond the N-1 criteria shown in Table I.” Response: The NERC requirement is intended as a minimum and Regions do have the right to use more stringent requirements if they choose. These requirements need not be included in the NERC standard if the Region does not wish for NERC to enforce them.

	The measures for 603 seem satisfactory. Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
MAPP Operations Subcommittee Allan Silk – Manitoba Hydro Paul Brune – NPPD Paul Koskela – Minnesota Power Larry Larson – Otter Tail Darrick Moe – WAPA Dick Pursley – Great River Energy Martin Trence – Xcel Energy Todd Gosnell – Omaha PPD Joseph Knight – MAPPCOR, S2	Requirements and Measurements – No. See attached MAPP table I, (inserted at the end of this document) to be used in place of table I, under section 603.1.3.1. Response: This issue has been discussed with MAPP and they are withdrawing this regional difference. Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Clay Young and 8 employees – South Carolina Electric & Gas, S1, S3, S5	Requirements and Measurements – No. SCE&G believes that the existing NERC PSS Table 1 defines the appropriate levels of performance. SCE&G and most of the Transmission Providers in the southeast plan beyond N-1 criteria. Most Transmission Providers in the southeast include a generator out simultaneous with the most critical transmission line out in their grid design. Appropriate criteria should also include the requirement that following the loss of a single facility; the transmission system shall be adjusted to a state that can tolerate the loss of the next single facility. Transmission systems that meet these kinds of test will continue to provide the expected and needed reliability of the grid. As currently written, it appears that Standard 603 is based on "least common denominator" thinking. That is, everyone does N-1 so let's reduce "all" reliability to that level. Adherence to 603, as written, will result in reduced reliability of the grid. NERC should not adopt practices that will result in reduced reliability. Response: The NERC requirement is intended as a minimum and Regions do have the right to use more stringent requirements if they choose. These requirements need not be included in the NERC standard if the Region does not wish for NERC to enforce them in that Region. Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Paul Johnson – AEP, S1,S3,S5, S6	Requirements and Measurements – Agree However, to avoid confusion the caption of column 3 should be changed to "Facilities Out of Service" (replace 'element'); and caption of row 3 should be changed to "Prevent Resulting in the loss of a single Facility". This would provide consistency with definitions supplied with this standard. Response: The table section has been modified to clarify the intent and correct any errors, in response to this and other comments. Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Dilip Mahendra – SMUD, S1	Requirements and Measurements – Agree

	Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
James Spearman & Florence Belser – PSC of S. Carolina, S9	Requirements and Measurements – No. The Public Service Commission of South Carolina recommends endorsing the standard, with the comment that planning for single contingency failures may not be adequate in all situations. It may be prudent to identify and plan to respond to multiple contingency failures whose expected frequency is above an appropriate probability threshold, and which pass an appropriate cost/benefit test. Response: The NERC requirement is intended as a minimum and Regions do have the right to use more stringent requirements if they choose. These requirements need not be included in the NERC standard if the Region does not wish for NERC to enforce them in the Region. This standard is for determining the SOL only. Planning for the future system is covered in another SAR. Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
SPP Operating Reliability WG Gerry Burrows – KCP&L, S1 Bob Cochran – SPS, S1 Peter Kuebeck – OG&E, S1 Scott Moore – AEP, S1 Dan Boezio – AEP, S1 Tom Stuchlik – Westar, S1 Matt Bordelon – CLECO, S1 Mike Crouch – WFEC, S1 Mike Gammon – KCP&L, S1 Kevin Goolsby – SPP, S2 Bo Jones – Westar, S1 Allen Klassen – Westar, S1 Thad Ness – AEP, S1 Harold Wyble – KCP&L, S1 Robert Rhodes – SPP, S2	Requirements and Measurements – Agree Replace “element(s)” with “facility(ies)” in the following places in Table I: heading of the third column, first column third row and in footnote (c). Response: The table section has been modified to clarify the intent and correct any errors, in response to this and other comments. Compliance Monitoring Process – Agree Levels of Non-compliance – No - see answer to question 5. Response: The drafting team does not disagree that the impacts of both can have reliability impacts. The majority of comments do not support financial penalties for methodology violations.
John Blazekovich - Exelon, S1,S3,S5,S6	Requirements and Measurements – No. Section 603.1.2 states “The methodology required in 603.1.1. shall state that system operating limits shall not violate the applicable facility ratings”. This statement is in conflict with the “Purpose” statement in section 600 which states that facility ratings need only be adhered to in order to avoid “cascading outages, uncontrolled system separation, and voltage and transient instability”. This would allow a system operating limit to violate an applicable facility rating that results in thermal overloads or low voltage that does not result in a cascading outage, uncontrolled system separation, and voltage and transient instability. In order to correct this, the purpose statement in section 600 needs to be rewritten to also include thermal overloads and low voltage that do not result in cascading outages and instability. Section 603.1.3 requires that system operating limits be established to “avoid system performance outside that prescribed in Table I”. Table I does not allow exceeding the applicable normal and emergency facility thermal or system voltage limits even if it does not result in cascading outage or instability. Therefore, section 603.1.3 is inconsistent with the “Purpose” statement in section 600. In

	order to correct this, the purpose statement in section 600 needs to be rewritten to also include thermal overloads and low voltage that do not result in cascading outages and instability Response: The Purpose and table section has been modified to clarify the intent and correct any errors, in response to this and other comments. Compliance Monitoring Process – No. Self Certification should be completed annually; data submittal or site visits should be performed on demand. Response: The standard addresses minimum requirements – a compliance monitor may choose to undertake a self-certification program annually or to increase the requirement under 603.4.2.2 to more frequently that once every ten years. Levels of Non-compliance – Agree
Raymond Mammarella – PPL, S1	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Carter Edge – S.E. Power Admin, S4, S5	Same comments as SERC Planning Standards Working Group listed above.
Tom Pruitt & 4 other employees – Duke Power, S1 & S5	Requirements and Measurements - No. Sections 603.1.4.2 and 603.1.4.5 need to be more specific. Section 603.1.4.3 should read **"Special protection systems or operating solutions."** What is a "remedial action plan"? Section 603.2.2 needs to be broken out to address each section (603.1.2, 603.1.3, and 603.1.4). Response: A remedial action plan is formal documentation of an operating solution. Compliance Monitoring Process – No. In section 603.4.1, explicitly state how the responsible entity would demonstrate compliance to the compliance monitor (CM). Specify the information package required. Response: The standard provides a high level description of such materials. The specifics will be developed when the compliance committee designs its compliance program. Levels of Non-compliance – No. Sections 603.5.1 and 603.5.2 should be swapped. For levels 3 and 4, develop non-compliance levels which reflect the severity of the consequences of non-compliance. Response: This is a judgment call, the general rationale for which was provided in the introductory material on the comment form. The drafting team has reconsidered and agrees with this suggested change. The change has been made.
Alan Boesch – NPPD, S1	Requirements and Measurements – No. Compliance Monitoring Process – No. Levels of Non-compliance – No
Tony Jankowski – We Energies, S4	Requirements and Measurements – No.

	Should only be the RA or PA, but not both! And not the TOP. Response: The functional model provides for the Transmission Operator function to define operating limits for the local network. The standard acknowledges that Reliability Authorities and Planning Authorities also provide input and in some cases calculate the limits. It is assumed that further revisions to the functional model will add greater clarity in this area. Compliance Monitoring Process – No. See response to 601. Response: The timeframes provided are minimum guidelines. Further guidance will be provided in the compliance plan associated with this standard when it is developed by the compliance monitor. Levels of Non-compliance – No. See response to 601, 602. Response: The philosophy of the standard is that non-compliance to the requirements associated with documenting a methodology is not as severe as the unavailability of the values themselves.
Don Chandler – CenterPoint, S1	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Tom Mielnik – MidAmerican, S3	Requirements and Measurements – No. While MidAmerican, a MAPP company, agrees that the Operating Security Limit should NOT be set to include all Category C and D events, we do believe that Category C and D events should be evaluated for likelihood and consequence of event. If an event is one that is more likely such as lines on a common tower for an extended length such as ten miles or more or is an event which results in catastrophic consequences such as cascading outages, then MidAmerican believes that these events should be considered for inclusion in setting the OSL. MidAmerican suggests that NERC include Category C and D events in the standard with the caveat that the likelihood and consequence of these events should be evaluated and more likely events or events that have significant consequences be considered for possible inclusion in the setting of the OSL. Response: The NERC requirement is intended as a minimum and Regions do have the right to use more stringent requirements if they choose. These requirements need not be included in the NERC standard if the Region does not wish for NERC to enforce them in the Region. Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Michael Sidiropoulos – Pacificorp, S1	Requirements and Measurements – No. State that 1.3.1 is a minimum performance criterion. Regional councils are free to adopt more stringent criteria. Response: The NERC requirement is intended as a minimum and Regions do have the right to use more stringent requirements if they choose. These requirements need not be included in the NERC standard if the Region does not wish for NERC to enforce them in the Region.

	Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Mitchell Needham – TVA, S1 Gary L. Jackson – TVA, S6 Mark Creech - TVA	Requirements and Measurements – No. Section 603.1.3 should include the wording "at a minimum" after the word performance. As prescribed in table 1 of section 603.1.3.1 This inclusion of the wording "at a minimum" should be used to support any region having regional differences such as events resulting in the loss of multiple elements Response: The NERC requirement is intended as a minimum and Regions do have the right to use more stringent requirements if they choose. These requirements need not be included in the NERC standard if the Region does not wish for NERC to enforce them in the Region. Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Mike Viles & 9 other employees – BPA Transmission, S1	Requirements and Measurements – Agree Define NPCC. Response: NPCC stands for the Northeast Power Coordinating Council, which is one of the ten NERC regions. Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Carey Gates – CalISO, S2	Requirements and Measurements – Agree In 603 2.1 the methodology used to determine values must be provided within 15 business days of request. We do not understand why it would take 15 days to provide a pre-established methodology. It could be a document that would be posted on a Transmission Owners website. We do not envision that the methodology would change very often once established. Response: The 15 business day requirement was included based upon the team's assumption for a reasonable amount of time to supply documentation that should be on file. The 15 days is intended to allow time for an entity to respond to a request considering the realities of staff availability and internal approval and communications processes. Compliance Monitoring Process – Agree Actually compliance verification by the compliance monitor at least once every ten years may be to long of a minimum period. Response: The standard addresses minimum requirements – a Region may choose to increase the requirement under 603.4.2.2 to more frequently than once every ten years. Levels of Non-compliance – Agree It would be helpful if a "table" illustrating the levels of non-compliance were added to this section. Response: The compliance committee will be asked to prepare an explanatory reference paper to be used with all standards.
Susan Morris – SERC, S2	Requirements and Measurements – No.

Bill Reinke – SERC, S2 Sam Stryker – Fayetteville PWS, S3, S4, S5 John Stickley – AECI, S1 Carter Edge – SEPA, S4,S5 John Troha – SERC, S2 Tim Ponseti – TVA, S1 Bill Thompson – Dominion Transmission, S1	Wording needs to be included that the level of performance specified is a minimum and that more stringent criteria for individual transmission providers or regions are permissible. Many of the Transmission Owners/Providers in SERC plan beyond N-1 criteria. Many SERC Members feel that adherence to 603 as written without this wording will result in reduced reliability in the SERC region. The requirements of 603 section 1.3 should be modified to include the following statement: "Table I contains a minimum level of performance. Some Transmission Owners and or regions plan for operations beyond the N-1 criteria shown in Table I." Response: The NERC requirement is intended as a minimum and Regions do have the right to use more stringent requirements if they choose. These requirements need not be included in the NERC standard if the Region does not wish for NERC to enforce them. This standard is for determining the system operating limits. Planning for the future system is covered in another SAR. The Transmission Owner has the ultimate responsibility to establish system operating limits which is a result of its fiduciary responsibility for its owned facilities. The Transmission Owner has ultimate responsibility and liability for owning, maintaining and operating its facilities. The Transmission Owner, then, is ultimately responsible for establishing system operating limits. While the Transmission Owner may voluntarily contract to have some other entity (function) perform some of the operations needed to ensure that fiduciary responsibility, it is the Transmission Owner that has ultimate responsibility. Neither NERC standards nor the Functional Model can allocate or transfer that responsibility to the RAs. Transmission Owners subject to state jurisdiction must typically obtain state regulatory approval to transfer control or operational authority over jurisdictional facilities to third parties. Forcing Transmission Owners to allow a third party, such as the RA, to cede ultimate responsibility for establishing system limits could trigger the need for state regulatory approvals. However, the Transmission Owners may voluntarily contract some functional responsibilities to other entities, like the RA, TOP, and TSP, but the ultimate responsibility would still reside with the Transmission Owner. Response: The standard recognizes the right of entities performing the facility owner function to determine the appropriate ratings for their facilities. The standard also requires that system operating limits respect the facility ratings. The standard does not require that owners cede their right to establish facility ratings to any third party. System operating limit determination requires wider-area information that the facility owner may not have. Please add TOs and TSPs to the requirements 603 section 1.1 for documenting the methodology used for determining system operating limits, as the draft standard only indicates RAs, PAs, and TOPs. Response: According to the functional model, the Transmission Owner and Transmission Service Provider have no responsibility for system operating limits. Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Gerald Rheault – Manitoba Hydro, S1, S3, S5, S6	Requirements and Measurements – Agree

	Manitoba Hydro agrees with the methodology presented in 603.1.3 but believes that the wording should be changed from "...the system operating limits are established such that operation within the system operating limit would avoid system performance outside that prescribed in Table I below" to "... the system operating limits be developed so that operation within the system operating limit will provide performance consistent with that prescribed in Table I below." Response: The table section has been modified to clarify the intent and correct any errors, in response to this and other comments. Also Requirement 603.1.3 (which includes Table 1), should address the need for actual system performance to meet performance standards. If events show that a system was operated to unsafe operating limits due to inadequate methodology, there should be a requirement to review and revise the methodology. Response: The drafting team understands this point. The standard attempts to remain true to NERC's mission to develop standards aimed towards performance objectives as opposed to prescriptive "how to" rules. There is a SAR related to disturbance analysis that may serve useful as a feedback loop to measure the effectiveness of these standards. The Transmission Provider should have the freedom to plan and operate beyond n-1 criteria if required for local reliability issues. The performance level listed in 603.1.3 should be clearly indicated as being the minimum requirements. Response: The NERC requirement is intended as a minimum and Regions do have the right to use more stringent requirements if they choose. These requirements need not be included in the NERC standard if the Region does not wish for NERC to enforce them in the Region. The footnote entitled d) as part of 603.1.3 does not appear to align with the statement it is applied to (Single Pole Block Normal Clearing) – the correct reference is footnote f) in the original NERC Table 1. Response: The table section has been modified to clarify the intent and correct any errors, in response to this and other comments. In the NPCC table, there is a footnote f) but the reference to this footnote in the table is not correct. The Cascading Outages column should be footnoted as c) Again the NERC table was edited incorrectly. Response: The NPCC regional difference will be reviewed and edited as appropriate. Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Peter Burke – American Transmission Company, S1	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Might it be reasonable to mention generator owners? Response: Generator owners were not listed here, as they do not have responsibility

	for determining system operating limits. Their facilities may contribute to the limits, but they do not calculate the limits. The functional model does not provide for the generator owner function to have the responsibility for determining the system operating limits, which requires more information than would be available to the generator owners. Levels of Non-compliance – Agree
Kirit Shah – Ameren, S1	Requirements and Measurements – No. In operation, a previous contingent outage (presumably not scheduled) could cause a facility to be above its continuous/normal rating, perhaps up to its short time rating if a) it does not exceed the short time used in the rating and b) an outage of this heavily loaded facility does not result in a parallel facility exceeding its emergency rating. Response: The equipment ratings identified in standards 601 and 602 are expected to be comprehensive, including time dependencies, and these limits should not be exceeded for single contingency situations. Compliance Monitoring Process – Agree Levels of Non-compliance – No. Needs clarification.
WECC Technical Studies Subcommittee Peter Mackin – Trans Agency of Northern Calif, S1 Chifong Thomas – Pacific G&E, S1 Esteban Martinez – Turlock Irrigation District, S1 Peter Krzykos – Ariz Public Service, S1 Joe Seabrook – Puget Sound, A1 Phil Park – BC Trans Co, S1 C V Chung – Seattle City Light, S9	Requirements and Measurements – Agree Footnote "d" in Table 1 does not appear to apply to Single Pole Block of a DC line. Response: The table section has been modified to clarify the intent and correct any errors, in response to this and other comments. Footnote "f" in Table 1A (in the column with the heading "Cascading Outages") probably should be replaced by footnote "c". Footnote "f" probably applies to contingencies listed in C.3. Response: The NERC requirement is intended as a minimum and Regions do have the right to use more stringent requirements if they choose. Therefore, there could be methodologies in which this footnote “c” would apply. 603.1.2, “the methodology required in 603.1.1 shall state that the system operating limits shall not violate the applicable facility rating”, may be already covered in 603.1.3 (the disturbance performance table), and, therefore, this section could be redundant. If so, then we also will not need 603.5.2, which references 603.1.2. Response: The table section has been modified to clarify the intent and correct any errors, in response to this and other comments. 603.1.2 requires a clearly stated commitment not to violate the applicable facility rating where as 603.1.3 requires the development of system operating limits which avoid system performance outside that prescribed in Table I, which implies, some system operating limits may be determined based results of Table I results to existing system operating limits. Compliance Monitoring Process – Agree Levels of Non-compliance – Agree

	Please see response to “Do you agree with the proposed requirements and measurements in section 603?”
FRCC OC, EC, MIC Linda Campbell – FRCC, S2 Paul Elwing – Lakeland Electric, S3 John Shafer – FP&L, S1 Don McInnis – FP&L S1 Patti Metro – FRCC, S2 Joe Krupar – FMPA, S3 Richard Gilbert – Lakeland Elect S3 Amy Long – Lakeland Elect S1 Roger Westphal – Gainesville Regional Utilities S5 Bob Remley – Clay Elect Coop S4 Steve Wallace - Seminole Elect Coop S4 Ted Hobson – JEA, S1	Requirements and Measurements – No. See our comment on 1.2 in question 6, it is the same concept here. In 1.3, shouldn't the methodology ensure that system operating limits are established to avoid conditions outside table I rather than "require"? In reviewing the table, we note that footnote d is not the same footnote for normal clearing currently in Table I of the planning standards. Should it be the same? Also, the current Table 1 in planning standard IA contains Category C and Category D. What is the rationale for not including these two categories as well? For 1.4, we suggest rewording from "The methodology required in 603.1.1.." to "The documentation shall..". In 1.4.5 we suggest deleting the last part of the sentence "in the conditions listed in 603.1.4.1-1.4.4. We are not sure what it adds. Response: The table section has been modified to clarify the intent and correct any errors, in response to this and other comments. Confusion exists in 2.1. We recommend that 2.1 be reworded to state- "The documentation shall be made available.." Also, in this statement remove compliance monitor. The compliance monitor notification should only be part of the compliance monitoring process. The important part of this measure is that the documentation is made available to those that need to review it such as the RA and PA. In 2.2 we recommend deleting the words "required in 603.1.1" as it is really unnecessary. Response: The drafting team reviewed the suggested change and believes the original wording more appropriately conveys the intent. Compliance Monitoring Process – No. Same questions we stated earlier about "either on or off site". Also, same questions we stated earlier about the compliance reset period. Response: The details regarding the use of on or off site investigations will be left to the compliance monitor when it designs the annual compliance review plan. A definition of performance reset period has been included in the standard in response to this and other comments. 4.1 sets a maximum time period. In general, when non-compliance is found, compliance monitor follow-up to ensure corrective action was taken should occur before the reset period expires. This is a compliance implementation issue. Levels of Non-compliance – No. 5.1 states that level one is if the methodology did not contain "the item" listed in 603.1.3. The item it refers to is the table (we think), so are not sure that this makes any sense. Did the SDT really mean to say level 1 would be if the methodology did not consider all of the conditions listed in the table? There needs to be some clarification here. 5.2 also seems to be that non-compliance would occur if the methodology did not ensure that SOLs did not violate the applicable facility ratings. The words "did not contain the item" here don't seem to make sense either. 5.3 looks like it is double hitting the areas already covered in 5.1 and 5.2. Is that appropriate? Also, in 5.3 it refers to any two items listed in 603.1.4 which is really a requirement of documentation, not methodology. This needs to be clarified. Response: 5.1, 5.2, and 5.3 will be changed to specifically state what “the item” is referring to.
Gary Won – IMO S2	Requirements and Measurements – Agree

	Compliance Monitoring Process – Agree Levels of Non-compliance – Agree See general comment below.
William J Smith – Allegheny Power, Segment 1	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Guy Zito, **NPCC CP9** Michael Schiavone – Nat Grid USA, S1 Roger Champagne – HQ Transenergie, S1 Ralph Rufrano – NYPA, S1 David Little – Nova Scotia Power, S1 David Kiguel – Hydro One, S1 Michael Potishnak – ISONE, S2 Barry Gee, Nat Grid USA, S1 Dan Stosick – ISONE, S2 Fernando Saavedra – ISONE, S2 Greg Campoli – NYISO, S2	Requirements and Measurements – Agree Footnote d on Table 1 is incorrect. The footnote e on Table 1A is the correct footnote. Response: The table section has been modified to clarify the intent and correct any errors, in response to this and other comments. For clarification purposes the Facility and Equipment Rating definitions should include time dependent ratings. Response: The equipment ratings identified in standards 601 and 602 are expected to be comprehensive, including time dependencies, and these limits should not be exceeded for single contingency situations Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Ken Githens – Allegheny Energy Supply – Segment 5	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Kathleen Goodman – ISONE, S2	Requirements and Measurements – Agree Footnote d on Table 1 is incorrect. The footnote e on Table 1A is the correct footnote. Response: The table section has been modified to clarify the intent and correct any errors, in response to this and other comments. For clarification purposes the Facility and Equipment Rating definitions should include time-dependent ratings. Response: The equipment ratings identified in standards 601 and 602 are expected to be comprehensive, including time dependencies, and these limits should not be exceeded for single contingency situations. Compliance Monitoring Process – Agree Levels of Non-compliance – Agree

9. **Do you agree with the proposed requirements and measurements in section 604? Do you agree with the proposed compliance monitoring process in section 604? Do you agree with the proposed levels of non-compliance in section 604?**

NERC Transmission Subcommittee Robert Reed – PJM Daniel Cooper – Michigan Public Power Agency Ken Donohoo – ERCOT Michael Gildea – Duke-Energy,	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – No response

North America Francis Halpin – BPA Tom Mallinger – MISO Darrick Moe – WAPA Scott Moore – AEP Bill Slater – Florida Power Corp Tom Stuchlik – Western Resources Joseph Styslinger – Southern Co David Thorne – DH Thorne Consultants Robert Waldele – NYISO Roman Carter – Southern Co John Ahr – Allegheny Power Susan Morris – SERC Ed Pfeiffer – Ameren Ray Palmieri – ECAR	
Mark Heimbach – PPL Generation, Segment 5	Requirements and Measurements – Agree Compliance Monitoring Process – Agree vels of Non-compliance – Agree
Roman Carter (& 9 other employees) - Southern Company Generation and Marketing, Segments 5,6 Terry Crawley & Roger Green – SOCO Generation, Segment 5	Requirements and Measurements – No. 604 1.1.1 and 604 2.2.2 should include Transmission Owner. Response: The standard recognizes the right of facility owners to determine the appropriate ratings for their facilities (See 602.). The standard also requires that system operating limits respect the facility ratings (See 603). The standard does not require that owners cede their right to establish facility ratings to any third party. Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
R T Sikes (& 4 other employees) – CenterPoint Energy Real Time Operations	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Alan Johnson – Mirant Americas Energy Mktg, Segment 6	Requirements and Measurements – No. What is the intent of the word “associated” as used in section 1.2? Are we talking about TOPs, PAs, TPs and RAs that are adjacent? Also, would like to see sections 2.2 and 2.3 modified to require the provision of system operating limits to generator and transmission owners upon request. These entities should have access to the data for use in analyzing the operation of their existing assets and for the planning of new assets. Response: The intent is to require the provision of this information to those who need it for reliability reasons. The standard does not intend that ALL transmission operators, for instance, receive all information. The sentence has been modified to attempt to add greater clarity. Compliance Monitoring Process – Agree Levels of Non-compliance – No. Would like to see level two modified to recognize generator and transmission

	owners. Response: Please response directly above.
SERC Planning Standards Working Group Clay Young – South Carolina Electric & Gas, Segment 3 Byron Stewart – TVA, S1 David Weekly – Municipal Electric Authority of Georgia – S1 Brian Moss – Duke Power, S1 Darrell Pace – Alabama Electric Cooperative, S1 Bob Jones – SoCo, S1 Kham Vongkhamchanh – Entergy, S1 Pat Huntley – SERC, S2	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
SERC Operations Planning Subcommittee Carter Edge – Southeastern Power Administration, S4&S5 William Gaither – South Carolina Public Service Auth, S1 Mike Miller – SoCo, S1 Roger Brand – Municipal Electric Authority of Georgia, S1 Phil Creech – Progress Energy (Carolina), S1 Gene Delk & Al McMeekin – South Carolina Electric and Gas, S1 Greg Ott – Alcoa/Yadkin, S1 Doug Newbauer – Georgia System Operations, S1 Mike Clements & Mark Creech – TVA, S1 Don Reichenbach – Duke Energy, S1 Lynna Estep – SERC, S2	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Robert Grover – PPL, S3	Requirements and Measurements – Agree The wording in Requirement 604.1.2 can be read that RAs must provide information to either: 1. All Transmission Operators and Planning Authorities (which is not possible) OR 8. RAs within the respective RAs area (which is not allowed) While a PA and a Transmission Operator can have more than 1 RA, the RA and TSP are restricted to one RA. To be precise you may want to separate Requirement 1.2 into two sentences.

	Response: The intent is to require the provision of this information to those who need it for reliability reasons. The standard does not intend that ALL transmission operators, for instance, receive all information. The sentence has been modified to attempt to add greater clarity. Compliance Monitoring Process – Agree Levels of Non-compliance – No Response
John Horakh – MAAC, S2	Requirements and Measurements – Agree The wording in Requirement 604.1.2 can be read that RAs must provide information to either: All Transmission Operators and Planning Authorities (which is not possible) OR RAs within the respective RAs area (which is not allowed) While a PA and a Transmission Operator can have more than 1 RA, the RA and TSP are restricted to one RA. To be precise you may want to separate Requirement 1.2 into two sentences. Response: See response to Robert Grover above. Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
David Thorne – PEPCO, S1	Same comments as Robert Grover, PPL, above. Please see the response to the referenced comments.
Todd Lucas & 5 other employees – SoCo Trans Plng, S1 and S3	Requirements and Measurements – No. The phrase "for the areas for which they are responsible" appears several times. We assume this is a reference to the functional model responsibilities. We believe it would be helpful if these areas of responsibility were re-stated in this standard, making it clear what these areas are for each entity. Response: This is a good point. The relationship between the entities performing these functions is not defined in this standard to avoid conflict with the *Functional Model* and to provide flexibility as allowed under the Functional Model. When all the NERC standards are completed, the functional model will be attached to them as a reference document. The drafting team does not believe it is appropriate to repeat the functional model in every standard. Compliance Monitoring Process – Agree Levels of Non-compliance – Agree In 604 5.2., the beginning of the sentence should read "All requested system operating limits were not provided to the transmission service provider…" to be consistent with 602 5.1. The measures require that the information be provided on a schedule. Having "upon request" and "with their respective schedules" in the same sentence is ambiguous. Response: The drafting team agrees that schedules need to allow sufficient time to develop ratings; however, the schedule must be driven by the users' need date for the information. Issuing an "unreasonable" schedule only promotes poor quality data and defeats the end objective. The standard does not attempt to establish the

	parameters for measuring an “achievable” schedule but leaves it to the involved parties
Lee Westbrook – OnCor, S1	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Darrel Richardson – Illinois Power, S1 S2	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Ed Davis – Entergy, S1	Requirements and Measurements – No. We believe the Transmission Owner has the ultimate responsibility to establish equipment operating limits which is a result of its fiduciary responsibility for its owned facilities. The Transmission Owner has ultimate responsibility and liability for owning, maintaining and operating its facilities to protect its stockholders’ and lending institutions’ investments. The Transmission Owner, then, is ultimately responsible for establishing system operating limits based on thermal ratings. While the Transmission Owner may voluntarily contract to have some other entity (function) perform some of the operations needed to ensure that fiduciary responsibility, it is the Transmission Owner that has ultimate responsibility. Neither NERC standards nor the Functional Model can allocate or transfer that responsibility to the RAs. Under state law, Transmission Owners must typically obtain state regulatory approval to transfer control or operational authority over jurisdictional facilities to third parties. Forcing Transmission Owners to allow a third party, such as the RA, to cede ultimate responsibility for establishing system limits could trigger the need for state regulatory approvals. However, the Transmission Owners may voluntarily contract some functional responsibilities to other entities, like the RA, TOP, and TSP, but the ultimate responsibility would still reside with the Transmission Owner. System operating limits (and interconnection reliability operating limits) are the lesser of the thermal, stability and voltage limits. The determination of each of these limits resides with different entities (functions). Equipment thermal limits and the thermal-based value of Tv for that equipment are the responsibility of the Transmission Owners. (For instance, a Transmission Owner might have dynamic thermal line ratings on specific transmission lines which are the responsibility of the TO.) Stability limits and associated value of Tv are the responsibility of the RA in the operating horizon and the PA in the planning horizon. Voltage limits are a responsibility shared by all three entities (functions). Therefore, we believe it is incorrect to say that any one entity (function) has ultimate responsibility to establish system operating limits. We also believe it is incorrect to say that any one entity (function) has ultimate responsibility to establish Interconnection Reliability Operating Limits. We suggest the above reasoning be used to revise this standard, the Operate Within IROL standard, and all other standards. Please add TOs and TSPs to the requirements 604 section 1.1 for establishing the system operating limits, as the draft standard only indicates RAs, PAs, and TOPs. The requirements of 604 section 1.2 limit distribution of system operating limits to the “area for which they are responsible”. All of the specified entities should

	provide the limits to all the other specified entities in the list. We suggest the following wording for requirements 1.2: 1.2 The reliability authority, planning authority, transmission operator, transmission service provider, and transmission owner shall provide all system operating limits to each of the other functions (entities) in this list. The measures for 604 seem satisfactory so long as the functional entities are changed to be consistent with the statements above. Response: The standard recognizes the right of facility owners to determine the appropriate ratings for their facilities (See 602.). The standard also requires that system operating limits respect the facility ratings (See 603). The standard does not require that owners cede their right to establish facility ratings to any third party. Per the Functional Model the transmission service provider does not have a role in determining system operating limits. Compliance Monitoring Process – No. We agree with the compliance monitoring process in section 604 if the functional entities are changed to be consistent with our comments above for the requirements and measures. Response: Same as immediately above. Levels of Non-compliance – No. We agree with the levels of non-compliance in section 604 if the functional entities are changed to be consistent with our comments above for the requirements and measures. Response: Same as immediately above.
MAPP Operations Subcommittee Allan Silk – Manitoba Hydro Paul Brune – NPPD Paul Koskela – Minnesota Power Larry Larson – Otter Tail Darrick Moe – WAPA Dick Pursley – Great River Energy Martin Trence – Xcel Energy Todd Gosnell – Omaha PPD Joseph Knight – MAPPCOR, S2	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Clay Young and 8 employees – South Carolina Electric & Gas, S1, S3, S5	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Paul Johnson – AEP, S1,S3,S5, S6	Requirements and Measurements – Agree Delete the word “function” from 604.2.3. You can not provide limits to a function only to an entity that performs a function.

	Response: The drafting team agrees. The wording in 604.2.3 has been revised. Compliance Monitoring Process – No. 604.4.1 requires self certification at least every three years and 604.4.2 requires annual verification that the data has been received by the Reliability Authority et.al. These activities appear redundant. Recommend deletion of 604.4.1. Response: 4.1 is monitoring compliance with Measure 2.1 which requires development of operating limits consistent with their operating limit methodology. However, 4.2 is monitoring compliance with 2.2 and 2.3 which require the reliability authorities, transmission operators, and planning authorities to provide the system operating limits to those who require it. Therefore, these different measures require different compliance approaches, and are not redundant. Levels of Non-compliance – Agree
Dilip Mahendra – SMUD, S1	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
James Spearman & Florence Belser – PSC of S. Carolina, S9	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
SPP Operating Reliability WG Gerry Burrows – KCP&L, S1 Bob Cochran – SPS, S1 Peter Kuebeck – OG&E, S1 Scott Moore – AEP, S1 Dan Boezio – AEP, S1 Tom Stuchlik – Westar, S1 Matt Bordelon – CLECO, S1 Mike Crouch – WFEC, S1 Mike Gammon – KCP&L, S1 Kevin Goolsby – SPP, S2 Bo Jones – Westar, S1 Allen Klassen – Westar, S1 Thad Ness – AEP, S1 Harold Wyble – KCP&L, S1 Robert Rhodes – SPP, S2	Requirements and Measurements – Agree Compliance Monitoring Process – No. The difference between what's required in Sections 4.1 and 4.2 is not clear. Why not just delete 4.1 and go with annual verification? Response: 4.1 is monitoring compliance with Measure 2.1 which requires development of operating limits consistent with their operating limit methodology. However, 4.2 is monitoring compliance with 2.2 and 2.3 which require the reliability authorities, transmission operators, and planning authorities to provide the system operating limits to those who require it. Therefore, these different measures require different compliance approaches, and are not redundant. Levels of Non-compliance – No – see response to question 5. Response: Please see the response to the reference earlier comment 5.
John Blazekovich - Exelon, S1,S3,S5,S6	Requirements and Measurements – No. Section 604.1.1 should be reworded as follows to be consistent with measure 604.2.1: The reliability authority, planning authority, and transmission operator shall establish system operating limits for the areas for which they are responsible ***consistent with the methodology described in 603.1***. Response: The drafting team believes that the relationship between the requirement and the measurement is appropriate and has not incorporated the suggested change. In section 604.1.2 it is not clear why transmission service providers are included. When the SAR was developed the comments from industry clearly

	stated that ATC calculations were not to be part of this standard. The NERC Functional Model Review Task Group Report dated January 1, 2003 defines transmission service providers as entities that "determines Available Transfer Capability and coordinates ATC with other Transmission Service Providers". Transmission service providers also need facility ratings to calculate ATC and yet there is no requirement under section 602.1.2 to provide them this data. Information required for ATC calculation should not be part of this standard because ATC calculations are not part of this standard. Response: While the calculation of ATC by the transmission service provider (TSP) is not within the scope of the standard, the TSP needs the system operating limits to perform its function as defined in the Functional Model. Requirement 604.1.2 should be reworded to not include transmission service providers and to make clear that system operating limits need only be provided as required. A reliability authority may not want system operating limits from a transmission operator because they are determining them by themselves. The following wording is suggested: The reliability authority, planning authority, and transmission operator shall provide system operating limits for the area for which they are responsible to their associated transmission operators, planning authorities, ~~transmission service providers~~, and reliability authorities ***as required.*** Transmission service provider should be removed from measure 604.2.2 for the reasons stated above (this standard does not include ATC calculations). Response: See immediately above for SDT response to excluding the TSP. Compliance Monitoring Process – Agree Levels of Non-compliance – No. Levels 3 & 4 should be switched (see question 11). Response: The drafting team does not disagree that the impacts of both can have reliability impacts. This is a judgment call, and the standard assumes that the lack of data can potentially halt the requestor's function whereas inconsistent/poor quality data will still allow some functionality on an appropriate basis.. "Level one: should be not applicable (not "Not Specified") current language is ambiguous. Response: This comment will be forwarded to NERC's general counsel for consideration.
Raymond Mammarella – PPL, S1	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Carter Edge – S.E. Power Admin, S4, S5	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Tom Pruitt & 4 other employees – Duke Power, S1 & S5	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree

Alan Boesch – NPPD, S1	Requirements and Measurements – No. Compliance Monitoring Process – No. Levels of Non-compliance – No
Tony Jankowski – We Energies, S4	Requirements and Measurements – No. Must only be RA or PA, but not both. Should not include TOP. Response: The standard attempts to remain as true to the functional model as possible. The model indicates that RAs, PAs and TOPs all have a role in establishing system operating limits within their defined scopes of responsibility. It is assumed that further revisions to the functional model will add greater clarity in defining the roles and relationships of each. Compliance Monitoring Process – Agree Levels of Non-compliance – No. Only one function responsible to establish limits. Agree with sanctions. Response: See response immediately above.
Don Chandler – CenterPoint, S1	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Tom Mielnik – MidAmerican, S3	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Michael Sidiropoulos – Pacificorp, S1	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Mitchell Needham – TVA, S1 Gary L. Jackson – TVA, S6 Mark Creech - TVA	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Mike Viles & 9 other employees – BPA Transmission, S1	Requirements and Measurements – No. In section 2.2 it is requested that the schedule established to provide the operating limits be established on a schedule that is agreed to by all the participants. As it presently reads, an unreasonable schedule could set by those not providing the limits. Response: Schedules need to allow sufficient time to develop ratings; however, the schedule must be driven by the RA, PA or TOP's need date for the information. Issuing an "unreasonable" schedule only promotes poor quality data and defeats the end objective. The standard does not attempt to establish the parameters for measuring an "achievable" schedule but leaves it to the involved parties. Compliance Monitoring Process – Agree Suggest switching 4.1 and 4.2 so the more frequent response is listed first. Response: The revision has been made. Levels of Non-compliance – Agree
Carey Gates – CalISO, S2	Requirements and Measurements – Agree

	(Same comment as question 1) Section 604.1.1.1 states that "The reliability authority, planning authority and transmission operator shall establish system operating limits for the areas for which they are responsible". This statement does not establish who has the "ultimate" responsibility for establishing SOLs. Response: The standard acknowledges that the RA, PA and TOP all have a role in the determination of operating limits, much as the Functional Model does. It is assumed that further revisions of the Functional Model will add greater clarity in this area. Compliance Monitoring Process – Agree Levels of Non-compliance – Agree It would be helpful if a "table" illustrating the levels of non-compliance were added to this section. Response: The compliance committee will be asked to prepare an explanatory reference paper to be used with all standards.
Susan Morris – SERC, S2 Bill Reinke – SERC, S2 Sam Stryker – Fayetteville PWS, S3, S4, S5 John Stickley – AECI, S1 Carter Edge – SEPA, S4,S5 John Troha – SERC, S2 Tim Ponseti – TVA, S1 Bill Thompson – Dominion Transmission, S1	Requirements and Measurements – No The Transmission Owner has the ultimate responsibility to establish system operating limits which is a result of its fiduciary responsibility for its owned facilities. The Transmission Owner has ultimate responsibility and liability for owning, maintaining and operating its facilities. The Transmission Owner, then, is ultimately responsible for establishing system operating limits. While the Transmission Owner may voluntarily contract to have some other entity (function) perform some of the operations needed to ensure that fiduciary responsibility, it is the Transmission Owner that has ultimate responsibility. Neither NERC standards nor the Functional Model can allocate or transfer that responsibility to the RAs. Transmission Owners subject to state jurisdiction must typically obtain state regulatory approval to transfer control or operational authority over jurisdictional facilities to third parties. Forcing Transmission Owners to allow a third party, such as the RA, to cede ultimate responsibility for establishing system limits could trigger the need for state regulatory approvals. However, the Transmission Owners may voluntarily contract some functional responsibilities to other entities, like the RA, TOP, and TSP, but the ultimate responsibility would still reside with the Transmission Owner. Please add TOs and TSPs to the requirements 604 section 1.1 for establishing the system operating limits, as the draft standard only indicates RAs, PAs, and TOPs. The requirements of 604 section 1.2 limit distribution of system operating limits to the "area for which they are responsible". All of the specified entities should provide the limits to all the other specified entities in the list. We suggest the following wording for requirements 1.2: 1.2 The reliability authority, planning authority(ies), transmission operator(s), transmission service provider(s), and transmission owner(s) shall provide all system operating limits to each of the other functions (entities) in this list. The measures for 604 seem satisfactory so long as the functional entities are changed to be consistent with the statements above.

	Response: The standard recognizes the right of facility owners to determine the appropriate ratings for their facilities (See 602.). The standard also requires that system operating limits respect the facility ratings (See 603). The standard does not require that owners cede their right to establish facility ratings to any third party. Per the Functional Model the transmission service provider does not have a role in determining system operating limits. Compliance Monitoring Process – Agree Change the functional entities to be consistent with the comments to question 15 above for the requirements and measures. (add references to TOs and TSPs). Response: Same as above. Levels of Non-compliance – Agree Change the functional entities to be consistent with the comments to question 15 above for the requirements and measures. (add references to TOs and TSPs). Response: Same as above.
Gerald Rheault – Manitoba Hydro, S1, S3, S5, S6	Requirements and Measurements – Agree In 604.1.1 there should be clarification of the term "for the areas for which they are responsible" – are these physical, geographical, functional, or electrical areas? Response: The intent is to require the provision of this information to those who need it for reliability reasons. The standard does not intend that ALL transmission operators, for instance, receive all information. The sentence has been modified to attempt to add greater clarity. In 604.2.1 there should be clarification of the words "Responsible entities"; this does not appear to be a defined term. Response: Responsible entities refer to all those listed in the requirement. The term is used to avoid repeating the list of entities needlessly. Compliance Monitoring Process – Agree In 604.1.1 there should be clarification of the term "for the areas for which they are responsible" – are these physical, geographical, functional, or electrical areas? Response: See above. In 604.2.1 there should be clarification of the words "Responsible entities"; this does not appear to be a defined term. Response: See above. Levels of Non-compliance – Agree
Peter Burke – American	Requirements and Measurements – Agree

Transmission Company, S1	The limits might need to be conveyed to NERC Regions for their use, especially if they are providing RA services. Response: It is up to the entity that establishes the limits to communicate the information to those entities that need it, including those entities not specifically mentioned in the standard. Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Kirit Shah – Ameren, S1	Requirements and Measurements – Agree Compliance Monitoring Process – No Response. Levels of Non-compliance – No Response.
WECC Technical Studies Subcommittee Peter Mackin – Trans Agency of Northern Calif, S1 Chifong Thomas – Pacific G&E, S1 Esteban Martinez – Turlock Irrigation District, S1 Peter Krzykos – Ariz Public Service, S1 Joe Seabrook – Puget Sound, A1 Phil Park – BC Trans Co, S1 C V Chung – Seattle City Light, S9	Requirements and Measurements – Agree Please remove the word "function" from 604.2.3 or else change it to "functions" and add "functions" to the end of the sentence. Response: The drafting team agrees. The wording in 604.2.3 has been revised. Compliance Monitoring Process – Agree Please remove the word "ratings" from 604.4.1. Response: The drafting team agrees. The wording in 604.4.1 has been revised. Levels of Non-compliance – Agree
FRCC OC, EC, MIC Linda Campbell – FRCC, S2 Paul Elwing – Lakeland Electric, S3 John Shafer – FP&L, S1 Don McInnis – FP&L S1 Patti Metro – FRCC, S2 Joe Krupar – FMPA, S3 Richard Gilbert – Lakeland Elect S3 Amy Long – Lakeland Elect S1 Roger Westphal – Gainesville Regional Utilities S5 Bob Remley – Clay Elect Coop S4 Steve Wallace - Seminole Elect Coop S4 Ted Hobson – JEA, S1	Requirements and Measurements – No. We are fine with the requirements however do have some comments on the measures. Measure 2.1 states "responsible entities". The standard language should be more specific on who this applies to. Response: Responsible entities refer to all those listed in the requirement. The term is used to avoid repeating the list of entities. Also, 2.1 might be more clear if it was reworded to say "..shall develop their system operating limits consistent with their documented system operating limit methodology." and leave off the 603.1 words. Response: For auditing purposes, the standard is more clear if is specifically references 603.1. The implication of measurement 2.2 is that the RA must have a document that lists and describes all SOLs on a time frame demanded by the individual TOPs. The reality is that the RA will in many cases rely on an on-line contingency analysis program that identifies the SOLs for the current operating condition. The infinite number of combinations of customer demand, generation dispatch, interchange schedules and equipment outages make it impossible to determine all SOLs ahead of time. The current wording makes the RA responsible for supplying what could be an unreasonable and impractical amount of SOL data. We would suggest the following wording for 2.2, "Reliability authorities and transmission operators shall provide system operating limits to transmission service providers and transmission operators on a schedule agreed to by the reliability authority, transmission operator, and

	transmission service provider." This same concern is held for measure 2.3, i.e. the schedule should be agreed by the PA, TSP, TO and RA's. Response: If the on-line program is available it should be used. The requirement does not require a specific format, document or list of SOLs. The limits have to be communicated. The drafting team agrees that schedules need to allow sufficient time to develop ratings; however, the schedule must be driven by the RA, PA or TOP's need date for the information. Issuing an "unreasonable" schedule only promotes poor quality data and defeats the end objective. The standard does not attempt to establish the parameters for measuring an "achievable" schedule but leaves it to the involved parties. Also, in measure 2.2, the RA and TOp are providing the SOL to TSP and TO in their area. This does not agree with the functions listed in 1.2 We then notice that 2.3 separates out who the PA provides to. We are not sure we understand why this has been separated in this manner. Response: The measures and requirements differ by the time frames for which the limits are being calculated. In one instance, the limits are for operational time frames and in the other, for planning time frames. Compliance Monitoring Process – No. Same comment as earlier about the "either on or off site" language. In 4.2 TSPs are not included and 2.2 shows the TSPs getting the SOLs from the RA. Need to be sure what it is. The performance reset period on 1 year seems to work with 4.2, but 4.1 is a 3 year cycle. See earlier comments. Response: 4.2 has been modified to show TSPs receiving SOLs from RAs. The use of off-site vs. on-site reviews will be decided by each region as they design their compliance program. Levels of Non-compliance – No. It looks like 5.2 and 5.4 are the same. What is the difference? Response: 5.2 allows for cases where some requested information is not provided. 5.4 is more severe because it is for the case where no requested information is provided.
Gary Won – IMO S2	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree See general comment below.
William J Smith – Allegheny Power, Segment 1	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Guy Zito, **NPCC CP9** Michael Schiavone – Nat Grid USA, S1 Roger Champagne – HQ Transenergie, S1	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree

Ralph Rufrano – NYPA, S1 David Little – Nova Scotia Power, S1 David Kiguel – Hydro One, S1 Michael Potishnak – ISONE, S2 Barry Gee, Nat Grid USA, S1 Dan Stosick – ISONE, S2 Fernando Saavedra – ISONE, S2 Greg Campoli – NYISO, S2	
Ken Githens – Allegheny Energy Supply – Segment 5	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Kathleen Goodman – ISONE, S2	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree

10. Do you agree with the proposed requirements and measurements in section 605? Do you agree with the proposed compliance monitoring process in section 605? Do you agree with the proposed levels of non-compliance in section 605?

NERC Transmission Subcommittee Robert Reed – PJM Daniel Cooper – Michigan Public Power Agency Ken Donohoo – ERCOT Michael Gildea – Duke-Energy, North America Francis Halpin – BPA Tom Mallinger – MISO Darrick Moe – WAPA Scott Moore – AEP Bill Slater – Florida Power Corp Tom Stuchlik – Western Resources Joseph Styslinger – Southern Co David Thorne – DH Thorne Consultants Robert Waldele – NYISO Roman Carter – Southern Co John Ahr – Allegheny Power Susan Morris – SERC Ed Pfeiffer – Ameren Ray Palmieri – ECAR	Requirements and Measurements – No The TS recommends clarify the intent of Requirement 605, 1.2. Specifically "transfer capabilities shall adhere to all applicable system operating limits" is a bit ambiguous. Reviewing the "transfer capability" definition did not help clarify the intent of 1.2. – see Q. 24, below Response: The intent of 605. is to require the RA and PA to clearly state that their methodology acknowledges and observes (i.e adheres) to all applicable system operating limits without being overly prescriptive regarding the mechanics of determining transfer capability. The use of a transfer capability that exceeded system operating limits would result in unreliable system performance. Compliance Monitoring Process – No The TS believes Requirements 605, 1.2. needs clarification before the proposed compliance monitoring process can be adequately evaluated. Response: See response above. Levels of Non-compliance – No response
Mark Heimbach – PPL Generation, Segment 5	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Roman Carter (& 9 other employees) - Southern Company Generation and Marketing, Segments 5,6 Terry Crawley & Roger Green – SOCO Generation, Segment 5	Requirements and Measurements – No. The Transfer capability methodology should be documented by the Transmission Owner and Operator, and supplied to the RA for implementation. Under 605 1.2, the statement "transfer capabilities shall adhere to all applicable system operating limits" is a bit ambiguous. Need to cross reference the definitions of Transfer Capability and Available Transfer Capability with the Functional Model.

	Response: Section 605.1.1. of the standard does not require the use of single methodology by RAs or PAs for determining transfer capabilities, nor is it the intent of the standard. The intent of 1.2. is to require the RA and PA to clearly state that their methodology clearly acknowledges and observes (i.e adheres) to all applicable system operating limits without being overly prescriptive. By industry consensus established during the development of the SAR associated with this standard, the standard cannot address Available Transfer Capability (ATC). Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
R T Sikes (& 4 other employees) – CenterPoint Energy Real Time Operations	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Alan Johnson – Mirant Americas Energy Mktg, Segment 6	Requirements and Measurements – No. There should only be one standard methodology for determining transfer capability. As presently written, it appears that section 1.1 would enable each RA and PA to create and implement its own methodology. If this is indeed the intent, then in section 2.1, the methodologies should be made available to the market participants. Response: Section 605.1.1. of the standard does not require the use of single methodology by RAs or PAs for determining transfer capabilities, nor is it the intent of the standard. The Reliability Authorities, Planning Authorities and Compliance Monitors are in positions to ensure that the Transfer Capability values are determined in accordance with applicable reliability criteria, which is sufficient to meet the objectives of this Standard. The SDT would encourage the responsible parities to use their own volition to make this methodology available to all interested parties, including market participants. During the development of the SAR associated with this standard, the industry consensus did not support the use of a single methodology by all parties. Compliance Monitoring Process – Agree. Levels of Non-compliance – No. In section 5.4, generator owners, transmission owners and transmission operators should be included Response: As drafted, Section 5.4 is consistent with Measure 2.1. However, since a Transmission Operator may be using Transfer Capability values to ensure reliable operation. Sections 2.1 and 5.4 have both been modified to include Transmission Operator. Generator owners and transmission owners must have their respective ratings adhered to when transfer capabilities are established but do not need the referenced information for reliability purposes.
SERC Planning Standards Working Group Clay Young – South Carolina Electric & Gas, Segment 3 Byron Stewart – TVA, S1 David Weekly – Municipal Electric Authority of Georgia – S1 Brian Moss – Duke Power, S1 Darrell Pace – Alabama Electric Cooperative, S1 Bob Jones – SoCo, S1	Requirements and Measurements – No. A new section (605.1.4) should read: "**The methodology required in 605.1.1 shall conform to good utility practice (e.g., NERC Reference Document: Transmission Transfer Capability—May 1995).**" Response: The drafting team understands this point. The standard attempts to remain true to NERC's mission to develop standards aimed towards performance objectives as opposed to prescriptive "how to" rules. Therefore, an entity may choose to incorporate the referenced NERC report (in whole or part) into their own methodology, this Standard does not require it.

Kham Vongkhamchanh – Entergy, S1 Pat Huntley – SERC, S2	Compliance Monitoring Process – Agree Levels of Non-compliance – Agree However, section 605.1.4 (proposed in our comment in question 18) should be incorporated into the Levels of Non-Compliance.
SERC Operations Planning Subcommittee Carter Edge – Southeastern Power Administration, S4&S5 William Gaither – South Carolina Public Service Auth, S1 Mike Miller – SoCo, S1 Roger Brand – Municipal Electric Authority of Georgia, S1 Phil Creech – Progress Energy (Carolina), S1 Gene Delk & Al McMeekin – South Carolina Electric and Gas, S1 Greg Ott – Alcoa/Yadkin, S1 Doug Newbauer – Georgia System Operations, S1 Mike Clements & Mark Creech – TVA, S1 Don Reichenbach – Duke Energy, S1 Lynna Estep – SERC, S2	Same comments as SERC Planning Standards Working Group listed above. Response: See response above to SERC PSWG.
Robert Grover – PPL, S3	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – No Response
John Horakh – MAAC, S2	Requirements and Measurements – Agree Does this allow that the methodology used by the RA can be different than the methodology used by the PA? Response: Section 605.1.1. of the standard does not require the use of single methodology by RAs or PAs for determining transfer capabilities, nor is it the intent of the standard. The Reliability Authorities, Planning Authorities and Compliance Monitors are in positions to ensure that the Transfer Capability values are determined in accordance with applicable reliability criteria, which is sufficient to meet the objectives of this Standard. Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
David Thorne – PEPCO, S1	Same comments as Robert Grover, PPL, above.
Todd Lucas & 5 other employees – SoCo Trans Plng, S1 and S3	Requirements and Measurements – No. Transfer Capability Methodology should be jointly developed and documented with the transmission operator, with the Reliability Authority responsible for implementation.

	Response: The standard does not prohibit transmission operator participation, but does not require it. The standard simply requires that the reliability authority have a documented methodology for determining transfer capabilities. Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Lee Westbrook – OnCor, S1	Requirements and Measurements – No. The Standard should make clear that, if no transfer capability values are requested or used by a reliability authority or planning authority, compliance is deemed to be demonstrated without submission of a methodology to the compliance monitor. Response: The drafting team understands this concern. Standard 604, Measure 2.2 and 2.3 states that Transfer Capability values will be provided "… on a schedule established by the Transmission Operator, Transmission Service Provider, and Reliability Authority.". The drafting team believes that if these entities do not require Transfer Capability values, then that fact would preclude the need for a methodology. The standard does not intend to require information if there is no user for it. Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Darrel Richardson – Illinois Power, S1 S2	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Ed Davis – Entergy, S1	Requirements and Measurements – No. Comments Transfer capability is determined by the TSP. In 605 section 1.1, please replace the RA and PA with TSP. Response: The development of transfer capabilities included in this standard are not assigned to the transmission service provider in the functional model, but rather to the functions listed in the standard. The values are supplied to the TSP, but they are not developed by them. The suggested change was not incorporated. The measures are OK. There will be Regional differences so please acknowledge that in section 3. Regional Differences. Response: No region has asked for a regional difference to this section. Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
MAPP Operations Subcommittee Allan Silk – Manitoba Hydro Paul Brune – NPPD Paul Koskela – Minnesota Power Larry Larson – Otter Tail Darrick Moe – WAPA Dick Pursley – Great River Energy Martin Trence – Xcel Energy Todd Gosnell – Omaha PPD Joseph Knight – MAPPCOR, S2	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Clay Young and 8 employees –	Requirements and Measurements – No.

South Carolina Electric & Gas, S1, S3, S5	A new section (605.1.4) should read: "**The methodology required in 605.1.1 shall conform to good utility practice (e.g., NERC Reference Document: Transmission Transfer Capability—May 1995).**" Response: The drafting team understands this point. The standard attempts to remain true to NERC's mission to develop standards aimed towards performance objectives as opposed to prescriptive "how to" rules. Therefore, an entity may choose to incorporate the referenced NERC report (in whole or part) into their own methodology, this Standard does not require it. Compliance Monitoring Process – Agree Levels of Non-compliance – Agree However, section 605.1.4 (proposed in our comment in question 18) should be incorporated into the Levels of Non-Compliance.
Paul Johnson – AEP, S1,S3,S5, S6	Requirements and Measurements – No. In May 1995 NERC published "Transmission Transfer Capability – A reference Document for Calculating and Reporting the Electric Power Transfer Capability of Interconnected Electric Systems". Does the SDT anticipate that a statement by a Reliability Authority or a Planning Authority stating that Transfer Capabilities will be determined by the this NERC document would meet the requirements of 605.2.1? Response: If the methodology meets the requirements of the standard, it will compliant with the NERC standard. Such an evaluation will occur when the compliance assessment is conducted. The Drafting Team does not have the authority to evaluate documents for compliance. What is the course of action if the RA and PA disagree on the methodology? Which functional entity has the final say? We believe the Standard should specify only one entity to be ultimately responsible. For this requirement we suggest it should be the PA. Suggested rewording: "The Planning Authority in coordination with the Reliability Authority shall document the methodology they use for determining transfer capabilities." Response: Section 605.1.1. of the standard does not require the use of single methodology by RAs or PAs for determining transfer capabilities, nor is it the intent of the standard. The Reliability Authorities, Planning Authorities and Compliance Monitors are in positions to ensure that the Transfer Capability values are determined in accordance with applicable reliability criteria, which is sufficient to meet the objectives of this Standard Compliance Monitoring Process – Agree Levels of Non-compliance – Agree. In 605.5.2.2, the word 'equipment' should be replaced with the word 'topics'. Response: This change has been made.
Dilip Mahendra – SMUD, S1	Requirements and Measurements – Agree Compliance Monitoring Process – Agree

	Levels of Non-compliance – Agree
James Spearman & Florence Belser – PSC of S. Carolina, S9	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
SPP Operating Reliability WG Gerry Burrows – KCP&L, S1 Bob Cochran – SPS, S1 Peter Kuebeck – OG&E, S1 Scott Moore – AEP, S1 Dan Boezio – AEP, S1 Tom Stuchlik – Westar, S1 Matt Bordelon – CLECO, S1 Mike Crouch – WFEC, S1 Mike Gammon – KCP&L, S1 Kevin Goolsby – SPP, S2 Bo Jones – Westar, S1 Allen Klassen – Westar, S1 Thad Ness – AEP, S1 Harold Wyble – KCP&L, S1 Robert Rhodes – SPP, S2	Requirements and Measurements – Agree Should there be a proposed methodology for ATC, TTC, etc calculations? Response: Available transfer capability (ATC) is outside the scope of this standard established during the development of the SAR associated with it. Industry consensus dictated that ATC is not to be included in this standard. The standard develops values *related* to TTC but does not directly deal with its determination. Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
John Blazekovich - Exelon, S1,S3,S5,S6	Requirements and Measurements – No. Requirement 605.1.1 should be reworded to make absolutely clear that ATC calculation are not included. This would also make clear that requirement 605.1.3.5 is not referring to TRM and CBM which are also not to be included in this standard. The following wording is suggested: The reliability authority and planning authority shall document the methodology they use for determining transfer capabilities. ***Available transfer capability (ATC) calculations and its associated margins (TRM and CBM) are not included in this standard.*** Response: Available transfer capability (ATC) is outside the scope of this standard established during the development of the SAR associated with it. Industry consensus dictated that ATC is not to be included in this standard. The standard develops values *related* to TTC but does not directly deal with its determination. . The suggested change was not made because a standard should list only the items that are required, not those that are not. Compliance Monitoring Process – No. Self Certification should be performed annually, data submittal or site visits performed on demand. Response: The drafting team believes three years is appropriate, however an RRO Compliance Program may elect to perform Self Certification on a more frequent basis. In addition, verification by information submittals and site visits can be carried out more frequently than required. Levels of Non-compliance – Agree
Raymond Mammarella – PPL, S1	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Carter Edge – S.E. Power Admin, S4, S5	Same comments as SERC Planning Standards Working Group listed above.

	Response: See referenced response above.
Tom Pruitt & 4 other employees – Duke Power, S1 & S5	Requirements and Measurements – No. This requirement needs more specificity (e.g., for section 605.1.3.5, which margins (CBM, TRM) are anticipated). How will market impacts of the methodology be handled? Assumptions made in section 605.1.3 will greatly impact transfer capability. For section 605.1.3.3, what assumptions are made for generator outages and other contingencies? Create 3 new sections: 605.1.3.6 should define which contingencies are used, 605.1.3.7 should describe the use of operating guides and redispatch options, and 605.3.8 should address reserve sharing group limits (are they handled or not?). A new section (605.1.4) should read **"The methodology required in 605.1.1 shall be technically correct (conform to good utility practice) and reference industry rating practices or other standards (e.g., IEEE, ANSI, CSA)."** Response: The drafting team understands this point. The standard attempts to remain true to NERC's mission to develop standards aimed towards performance objectives as opposed to prescriptive "how to" rules. The respondent should note that assumption pertaining to contingencies considered, redispatch options, reserve-sharing implications may be included in the methodologies prepared by the responsible Reliability Authorities and Planning Authorities. Also note that TRM and CBM, although margins, are commercial quantities and are not addressed in this Standard. The term 'reliability margins' in section 1.3.5 are reliability based planning and operational margins. Section 605.1.3 requires RAs and PAs to document how their transfer capability methodology addresses topology, system demand, generation dispatch, etc. We believe that this methodology should be defined as part of this standard and any regional differences should also be documented as part of this standard and subject to industry review as part of the standard process. Response: Section 605.1.1. of the standard does not require the use of single methodology by RAs or PAs for determining transfer capabilities, nor is it the intent of the standard. Any regional differences are to be part of this standard. None have been proposed as part of this section. Compliance Monitoring Process – Agree Levels of Non-compliance – No. Section 605.5.1 should read: "Level one: The transfer capability methodology does not contain 605.1.2 or address one of the items listed in 605.1.3 **or does not meet 605.1.4 (is technically incorrect -- does not conform to good utility practice)."** Section 605.5.2.2 should read ". . . types listed in 605.1.3 **or meet 605.1.4**" Section 605.5.3.2 should read ". . . types listed in 605.1.3 **or meet 605.1.4**" Response: See response to Mr. Pruitt's first comment. 'Good utility practice' can have varying definitions from area to area and is problematic to measure.
Alan Boesch – NPPD, S1	Requirements and Measurements – No. Compliance Monitoring Process – No. Levels of Non-compliance – No
Tony Jankowski – We Energies, S4	Requirements and Measurements – No. Only one function, not both.

	Response: The RA and PA functions are separate functions and need to document and make available their respective methodologies. Compliance Monitoring Process – No. See 601 comment. Response: See above. Levels of Non-compliance – No See 601,602 comment. Response: See above.
Don Chandler – CenterPoint, S1	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Tom Mielnik – MidAmerican, S3	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Michael Sidiropoulos – Pacificorp, S1	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Mitchell Needham – TVA, S1 Gary L. Jackson – TVA, S6 Mark Creech - TVA	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Mike Viles & 9 other employees – BPA Transmission, S1	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Carey Gates – CalISO, S2	Requirements and Measurements – Agree In 605 2.1 the methodology used to determine values must be provided within 15 business days of request. We do not understand why it would take 15 days to provide a pre-established methodology. It could be a document that would be posted on a Transmission Owners website. We do not envision that the methodology would change very often once established. Response: The 15 business day requirement was included based upon the team's assumption for a reasonable amount of time to supply documentation that should be on file. The 15 days is intended to allow time for an entity to respond to a request considering the realities of staff availability and internal approval and communications processes. Compliance Monitoring Process – Agree Actually compliance verification by the compliance monitor at least once every ten years may be to long of a minimum period. Response: The "at least once every ten years" is a maximum time between actual verifications, not a minimum time period. Under the standard, the compliance monitor could perform verifications more frequent if deemed appropriate. Levels of Non-compliance – Agree It would be helpful if a "table" illustrating the levels of non-compliance were added to this section.

	Response: The table is included at the end of the standard for reference. Repeating it in each section is redundant. If the commenter intended that the standard be formatted differently, this will be forwarded to NERC's general counsel for consideration upon clarification of the intent of the commenter.
Susan Morris – SERC, S2 Bill Reinke – SERC, S2 Sam Stryker – Fayetteville PWS, S3, S4, S5 John Stickley – AECI, S1 Carter Edge – SEPA, S4,S5 John Troha – SERC, S2 Tim Ponseti – TVA, S1 Bill Thompson – Dominion Transmission, S1	Requirements and Measurements – No. Transfer capability can also be determined by the TSP(s). The RA and PA(s) should own and be responsible for the methodologies used to determine transfer capabilities for various time horizons; however, the actual calculations for transfer capability can be performed by the TSP(s) if necessary to administer the tariff. In this case, the TSP(s) must follow the methodology. Response: The drafting team and industry consensus agrees that Transfer Capability is a reliability quantity and as such they are the responsibility of the Reliability and/or Planning Authorities. If it is appropriate, either of these functions could delegate the actual calculation to another entity. However, the Reliability Authority and/or the Planning Authority remain the responsible entity. The TSP *function* does not have to follow the same methodology because it does not calculate transfer capabilities as defined in this standard, but must not violate the transfer capabilities determined for reliability purposes. The TSP *function* will use the results of the transfer capability methodology as an input to determine ATC, for example. Section 1.1.1 should be re-worded as follows: "The reliability authority and planning authority(ies) shall document the methodology that is used for determining transfer capabilities." Response: Section 605.1.1. of the standard does not require the use of single methodology by RAs or PAs for determining transfer capabilities, nor is it the intent of the standard. This was established by industry comments during the development of the SAR. In section 3 - Regional Differences, please state that Regional differences will exist and will be specified in the methodology whether originating with requirements of the TO(s), TSP(s), RA or PA(s). Response: Any regional differences are to be part of this standard. None have been proposed as part of this section. Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Gerald Rheault – Manitoba Hydro, S1, S3, S5, S6	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Manitoba Hydro agrees with the compliance process in general for this requirement but have concern relative to frequency as stated in 605.4.2.2. The compliance monitor is restricted to verifying by information submittal once every 10 years or due to a complaint. If there is good reason to suspect non-compliance shouldn't the compliance monitor have the authority to request verification at any time? For example, an incident in another region of the country might bring to light possible vulnerabilities in other systems. The approach should obviously not to be to "catch people out" but to provide some incentive to "pull one's socks up". Response: The "at least once every ten years" is a maximum time between actual verifications, not a minimum time period. Under the standard, the compliance

	monitor could perform verifications more frequent if deemed appropriate. Levels of Non-compliance – Agree
Peter Burke – American Transmission Company, S1	Requirements and Measurements – Agree Possibly allow for the Transmission Owner to help determine methodology. Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Kirit Shah – Ameren, S1	Requirements and Measurements – No. Transfer capability should be split as a separate standard. Response: During the development of the SAR associated with this standard, it was decided that the best course was to develop the transfer capability requirements as part of the standard. There appears to be no appreciable benefit to splitting it out, as it is already a separate requirement. Compliance Monitoring Process Levels of Non-compliance
WECC Technical Studies Subcommittee Peter Mackin – Trans Agency of Northern Calif, S1 Chifong Thomas – Pacific G&E, S1 Esteban Martinez – Turlock Irrigation District, S1 Peter Krzykos – Ariz Public Service, S1 Joe Seabrook – Puget Sound, A1 Phil Park – BC Trans Co, S1 C V Chung – Seattle City Light, S9	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree We agree with the philosophy of increasing penalty from not providing some information, providing wrong information and not providing any information at all. However, this also means that there is no distinction between missing between one limit and most of the limits. This is a disincentive for people to improve compliance. Response: The levels of non-compliance for this requirement attempt to provide 'partial credit' for methodologies that contain most, but not all, of the required items. Also, please change "equipment types" to "items" in Sections 605.5.2.2 and 605.5.3.2. Response: This change has been made.
FRCC OC, EC, MIC Linda Campbell – FRCC, S2 Paul Elwing – Lakeland Electric, S3 John Shafer – FP&L, S1 Don McInnis – FP&L S1 Patti Metro – FRCC, S2 Joe Krupar – FMPA, S3 Richard Gilbert – Lakeland Elect S3 Amy Long – Lakeland Elect S1 Roger Westphal – Gainesville Regional Utilities S5 Bob Remley – Clay Elect Coop S4 Steve Wallace - Seminole Elect Coop S4 Ted Hobson – JEA, S1	Requirements and Measurements – No. We have the same comment on 1.2 as in earlier in questions. In addition to that, 1.2 could be interpreted to exclude outage transfer distribution factor (OTDF) cutoffs which is an accepted practice for determination of transfer capabilities. The problem is that 605.1.2 refers to all applicable SOLs which ties back to 603.1.2 which states that SOLs shall not violate facility ratings. The accepted practice of excluding certain overload of facility rating with very low OTDFs should be explicitly acknowledged in Standard 605. Also 1.3 is a requirement that documentation shall include.., not the methodology. For measure 2.1 see our earlier comments about the wording documentation vs methodology and also the concern about compliance monitor being in this measure. Response: See response to the referenced earlier comments. Compliance Monitoring Process – No. Same question as earlier on "on or off site". Same question about reset period. Response: See response to the referenced earlier comments.

	Levels of Non-compliance – No. 5.1 seems to mix compliance to requirements of the methodology and what is required in documentation. It is confusing and needs clarification. 5.2, 5.3 and 5.4 are all very confusing. There needs to be a better way to identify the appropriate compliance levels and make sure we are not including things that are not as important as others. Response: The drafting team is interested in specific alternatives, but absent any, feels that the non-compliance levels will have to suffice.
Gary Won – IMO S2	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – No The level 2 and 3 violations seem more severe than the violation addressed in level 4. Response: The drafting team reviewed the levels of non-compliance in this section and believes they are consistent with other similar sections of this standard (e.g. 601 and 603). The philosophy is that if the methodology is not supplied, it is assumed that it does not exist.
William J Smith – Allegheny Power, Segment 1	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Guy Zito, **NPCC CP9** Michael Schiavone – Nat Grid USA, S1 Roger Champagne – HQ Transenergie, S1 Ralph Rufrano – NYPA, S1 David Little – Nova Scotia Power, S1 David Kiguel – Hydro One, S1 Michael Potishnak – ISONE, S2 Barry Gee, Nat Grid USA, S1 Dan Stosick – ISONE, S2 Fernando Saavedra – ISONE, S2 Greg Campoli – NYISO, S2	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Ken Githens – Allegheny Energy Supply – Segment 5	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Kathleen Goodman – ISONE, S2	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree

11. Do you agree with the proposed requirements and measurements in section 606? Do you agree with the proposed compliance monitoring process in section 606? Do you agree with the proposed levels of non-compliance in section 606?

NERC Transmission Subcommittee Robert Reed – PJM Daniel Cooper – Michigan Public Power Agency Ken Donohoo – ERCOT Michael Gildea – Duke-Energy,	Requirements and Measurements – No The TS recommends enhancing both Requirements 605 and 606 "Transfer Capabilities." Transfer capabilities should be more descriptive including differentiating ATC from TC, and a notation of how to determine ATC and TC.

North America Francis Halpin – BPA Tom Mallinger – MISO Darrick Moe – WAPA Scott Moore – AEP Bill Slater – Florida Power Corp Tom Stuchlik – Western Resources Joseph Styslinger – Southern Co David Thorne – DH Thorne Consultants Robert Waldele – NYISO Roman Carter – Southern Co John Ahr – Allegheny Power Susan Morris – SERC Ed Pfeiffer – Ameren Ray Palmieri – ECAR	Response: During the development of the SAR associated with this standard, industry consensus did not support the inclusion of ATC in this standard. For this reason, the standard does not address ATC. Available transfer capability (ATC) calculations and its associated margins (TRM and CBM) are not included in this standard. Compliance Monitoring Process – No The TS believes the TC Requirements need clarification before the proposed compliance monitoring process can be adequately evaluated. Response: See response immediately above. Levels of Non-compliance – No response
Mark Heimbach – PPL Generation, Segment 5	Requirements and Measurements – Agree Compliance Monitoring Process – Agree vels of Non-compliance – Agree
Roman Carter (& 9 other employees) - Southern Company Generation and Marketing, Segments 5,6 Terry Crawley & Roger Green – SOCO Generation, Segment 5	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
R T Sikes (& 4 other employees) – CenterPoint Energy Real Time Operations	Requirements and Measurements – No. We believe this should include input from the Transmission Operator. Response: While in some instances the Transmission Operator may have the necessary information to determine the transfer capabilities, the Reliability Authority and Planning Authority will always have the necessary information. An example would be an interface made up of lines operated by more than 1 Transmission Operator. Although, the TOP may provide input, this function is not responsible for determining transfer capabilities in the functional model. Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Alan Johnson – Mirant Americas Energy Mktg, Segment 6	Requirements and Measurements – Agree Compliance Monitoring Process – No. Suggest section 4.3 be modified to include the generator owner function. Response: This section has been revised to allow any impacted party to levy a complaint. Levels of Non-compliance – No.
SERC Planning Standards Working Group Clay Young – South Carolina Electric & Gas, Segment 3	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree

Byron Stewart – TVA, S1 David Weekly – Municipal Electric Authority of Georgia – S1 Brian Moss – Duke Power, S1 Darrell Pace – Alabama Electric Cooperative, S1 Bob Jones – SoCo, S1 Kham Vongkhamchanh – Entergy, S1 Pat Huntley – SERC, S2	
SERC Operations Planning Subcommittee Carter Edge – Southeastern Power Administration, S4&S5 William Gaither – South Carolina Public Service Auth, S1 Mike Miller – SoCo, S1 Roger Brand – Municipal Electric Authority of Georgia, S1 Phil Creech – Progress Energy (Carolina), S1 Gene Delk & Al McMeekin – South Carolina Electric and Gas, S1 Greg Ott – Alcoa/Yadkin, S1 Doug Newbauer – Georgia System Operations, S1 Mike Clements & Mark Creech – TVA, S1 Don Reichenbach – Duke Energy, S1 Lynna Estep – SERC, S2	Same comments as SERC Planning Standards Working Group listed above.
Robert Grover – PPL, S3	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance –No Response
John Horakh – MAAC, S2	Requirements and Measurements – Agree Compliance Monitoring Process – Agree In 4.4.1, replace “which” with “that”. Response: Agree, the comment has been incorporated. Levels of Non-compliance – Agree
David Thorne – PEPCO, S1	Same comments as Robert Grover, PPL, above.
Todd Lucas & 5 other employees – SoCo Trans Plng, S1 and S3	Requirements and Measurements – Agree We agree that the Reliability Authority and Planning Authority should establish the transfer capabilities as long as the methodology was jointly developed with the transmission operator. (See comment to question 18. --- #10 in this document, “Transfer Capability Methodology should be jointly developed and documented with the transmission operator, with the Reliability Authority responsible for

	implementation. ") Response: While in some instances the Transmission Operator may have the necessary information to determine the transfer capabilities, the Reliability Authority and Planning Authority will always have the necessary information. An example would be an interface made up of lines operated by more than 1 Transmission Operator. Although, the TOP may provide input, this function is not responsible for determining transfer capabilities in the functional model. Compliance Monitoring Process – Agree Levels of Non-compliance –No Response
Lee Westbrook – OnCor, S1	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Darrel Richardson – Illinois Power, S1 S2	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Ed Davis – Entergy, S1	Requirements and Measurements – No. Comments Transfer capability is determined by the TSP. In 606 section 1.1, please replace the RA and PA with TSP. Response: The TSP is responsible for calculating the ***Available*** Transfer Capability. Available transfer capability (ATC) calculations and its associated margins (TRM and CBM) are not included in this standard, respecting industry consensus during the drafting of the SAR associated with this standard. The Transfer Capability as described in this standard is used as an input to the ATC calculation. The measures are OK. There will be Regional differences so please acknowledge that in section 3. Regional Differences. Response: Specific regional differences that are identified will be added to the standard, but no region has asked for a difference in this section. Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
MAPP Operations Subcommittee Allan Silk – Manitoba Hydro Paul Brune – NPPD Paul Koskela – Minnesota Power Larry Larson – Otter Tail Darrick Moe – WAPA Dick Pursley – Great River Energy Martin Trence – Xcel Energy Todd Gosnell – Omaha PPD Joseph Knight – MAPPCOR, S2	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Clay Young and 8 employees – South Carolina Electric & Gas, S1, S3, S5	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Paul Johnson – AEP, S1,S3,S5, S6	Requirements and Measurements – No.

	1.1: Suggest rewording as follows: "The Planning Authority in coordination with the Reliability Authority shall establish and . . " Response: The Planning Authority is responsible for long-term (generally 1 year and beyond). The Reliability Authority is responsible for real time and therefore will need to revise transfer capabilities based on forecasted or actual system configuration. Therefore no change is necessary. 1.1: Suggest inserting "service:" ". . . Transmission Operator, Transmission Service Provider functions, and NERC and its Regions." Response: The suggested change has been made. In measurement 2.2, NERC appears to be able to request intra-regional Transfer Capabilities from individual Reliability Authorities and Planning Authorities. Often these quantities are not required for the reliability or planning of the system. Recommend that 2.2 be modified, and measure 2.3 be added as follows: 2.2 Responsible entities shall supply Transfer Capability values as requested to Reliability Authorities, Transmission Service Providers, Planning Authorities and Transmission Operators on a schedule established by the Reliability Authority, Planning Authority, Transmission Service Provider, and Transmission Operator. 2.3. Responsible entities shall supply INTERREGIONAL Transfer Capability values as requested to NERC, its Regions, Reliability Authorities, Transmission Service Providers, Planning Authorities and Transmission Operators on a schedule established by the Reliability Authority, Planning Authority, Transmission Service Provider, Transmission Operator, NERC and its Regions. Response: NERC may require intraregional transfer capabilities for reliability assessments. For this reason, the suggested change was not made. It is implicit in all NERC standards that requests subject to compliance will be made only for information necessary for an entity to perform its reliability function in the functional model. Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Dilip Mahendra – SMUD, S1	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
James Spearman & Florence Belser – PSC of S. Carolina, S9	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
SPP Operating Reliability WG Gerry Burrows – KCP&L, S1 Bob Cochran – SPS, S1 Peter Kuebeck – OG&E, S1 Scott Moore – AEP, S1	Requirements and Measurements – No. It is very cumbersome and can often times be very confusing when two entities are given responsibility for the same task. The

Dan Boezio – AEP, S1 Tom Stuchlik – Westar, S1 Matt Bordelon – CLECO, S1 Mike Crouch – WFEC, S1 Mike Gammon – KCP&L, S1 Kevin Goolsby – SPP, S2 Bo Jones – Westar, S1 Allen Klassen – Westar, S1 Thad Ness – AEP, S1 Harold Wyble – KCP&L, S1 Robert Rhodes – SPP, S2	requirements outlined in 1.1, 2.1 and 2.2 call for both the reliability authority and the planning authority to develop and provide transfer capabilities. We suggest that the planning authority should be ultimately responsible for identifying and quantifying the transfer capabilities. However, the planning authority should thoroughly coordinate this effort with the reliability authority. Wording such as "The planning authority shall coordinate with the planning authority to establish…" would be better. Following this line of thought with the measures in 2.1 and 2.2, wording should be changed to reflect the planning authority's ultimate responsibility. "The planning authority entity shall…" makes a better fit. Response: The Planning Authority is responsible for long-term (generally 1 year and beyond). The Reliability Authority is responsible for real time and therefore will need to revise transfer capabilities based on forecasted or actual system configuration. According to the functional model, both functions are responsible transfer capability determination. Are the studies used to determine transfer capabilities intra-regional or interregional? Response: Both. The standard will be revised to specify the reporting requirements for Intra regional and inter regional transfer capabilities. The schedule referred to in 2.2 should be mutually agreeable to all entities. Response: The drafting team agrees that schedules need to allow sufficient time to develop ratings; however, the schedule must be driven by the users' need date for the information. Issuing an "unreasonable" schedule only promotes poor quality data and defeats the end objective. The standard does not attempt to establish the parameters for measuring an "achievable" schedule but leaves it to the involved parties. Compliance Monitoring Process – Agree Levels of Non-compliance – Agree, but see response to question 5. *If an incorrect limit is calculated or a limit is not communicated, the financial consequences may be basically the same.* Response: The drafting team does not disagree that the impacts of both can have reliability impacts. This is a judgment call, and the standard assumes that the lack of data can potentially halt the requestor's function whereas inconsistent/poor quality data will still allow some functionality on an appropriate basis.
John Blazekovich - Exelon, S1,S3,S5,S6	Requirements and Measurements – No. Measure 606.2.1 needs to be reworded as follows to reflect transfer capability not ratings:Responsible entities shall develop their transfer capabilities consistent with their ratings ***transfer capability*** methodology, described in 605.1.1. Response: Agreed. Ratings will be changed to transfer capability.

	The same is also true in section 606.5.3. In section 606.5.4 “transfer capability ratings” needs to be replaced with “transfer capability ***values***”. Response: Agreed. The correction has been made. In measure 606.2.2, the term “transmission service provider” should be removed since this standard does not deal with ATC calculations. In addition, why would a transmission service provider need transfer capability values when their function is to calculate ATC? Response: The standard allows for a transmission service provider to request the transfer capability if it is needed. The Transfer Service Provider will need the transfer capability to determine the ATC to ensure that reliability limits are incorporated. Some Regions currently calculate transfer capability values for use in the NERC seasonal assessments. In this standard, why are the Regions excluded from having methodologies for determination of transfer capabilities and providing them to the NERC? Response: The standard does not prevent development and usage of regional methodologies for determining transfer capabilities within the region. The methodology may be used for other purposes such as seasonal assessments for NERC. Compliance Monitoring Process – Agree Levels of Non-compliance – No. We feel that inconsistent methodology should be the most severe level of noncompliance (level 4). Response: The assumption is that providing no data was a more severe level of noncompliance (level 4) than inconsistent methodology (level 3) because there is no basis in which to monitor the system if there is no data provided. For this reason, the suggested change was not made.
Raymond Mammarella – PPL, S1	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Carter Edge – S.E. Power Admin, S4, S5	Same comments as SERC Planning Standards Working Group listed above.
Tom Pruitt & 4 other employees – Duke Power, S1 & S5	Requirements and Measurements – Agree Fix typo's (they are in fact typo's, right?) in sections 606.2.1, 606.5.3, and 606.5.4 (transfer capability methodology vs. ratings methodology). Response: Agreed. Section 606.5.4 will be changed to transfer capabilities instead of transfer capabilities ratings. Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Alan Boesch – NPPD, S1	Requirements and Measurements – No.

	Compliance Monitoring Process – No. Levels of Non-compliance – No
Tony Jankowski – We Energies, S4	Requirements and Measurements – No. Only one function, not both. Response: The purpose of the standard requires that transfer capabilities be provided as necessary to plan and operate the bulk electric system. The transfer capabilities must be provided to both the reliability authority and planning authority to satisfy the purpose of the standard. The Planning Authority is responsible for long-term (generally 1 year and beyond). The Reliability Authority is responsible for real time. The functional model assigns responsibility for transfer capability determination to both functions. Compliance Monitoring Process – Agree. Levels of Non-compliance – Agree
Don Chandler – CenterPoint, S1	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – No response.
Tom Mielnik – MidAmerican, S3	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Michael Sidiropoulos – Pacificorp, S1	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Mitchell Needham – TVA, S1 Gary L. Jackson – TVA, S6 Mark Creech - TVA	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Mike Viles & 9 other employees – BPA Transmission, S1	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree Suggest switching 4.1 and 4.2 so the more frequent response is listed first. Response: The order does not change the intent of the standard and makes logical sense. The change has been made.
Carey Gates – CalISO, S2	Requirements and Measurements – Agree We agree with the general concept but with several questions and ideas. Section 606 1.1 requires the RA or PA to “establish and provide transfer capabilities requested by their associated RA, PA, TO, TP and NERC and it’s regions”. Please confirm that the term “associated RA” refers to other or adjacent RA’s in the same interconnection. The standard should also allow the RA or PA to

	recommend to the "associated RA, PA, TO, TP and NERC and it's regions" standards that it fells needs to be developed that have not been identified. Section 606 2.2 requires the responsible entity to provide facility ratings to NERC and It's regions, the RA, PA TSP, and TO on a schedule established by NERC and It's regions, the RA, PA TSP, and TO. This will lead to many varying schedules and may become confusing. Maybe the values need to be communicated initially and then each time a change is made or a new facility is added. Response: 606.1.1 has been slightly modified to add greater clarity. The drafting team agrees that there is a possibility for varying schedules, but the alternative is to arbitrarily set a universal schedule in the standard, which may not be reasonable for all parties. Compliance Monitoring Process – Agree Levels of Non-compliance – Agree It would be helpful if a "table" illustrating the levels of non-compliance were added to this section. Response: The compliance committee will be asked to develop an explanatory reference paper to be used with all standards.
Susan Morris – SERC, S2 Bill Reinke – SERC, S2 Sam Stryker – Fayetteville PWS, S3, S4, S5 John Stickley – AECI, S1 Carter Edge – SEPA, S4,S5 John Troha – SERC, S2 Tim Ponseti – TVA, S1 Bill Thompson – Dominion Transmission, S1	Requirements and Measurements – No. Add the following sentence to section 1.1.1: The TSP(s) can also establish and provide transfer capabilities in accordance with the methodologies determined by the RA and the PA(s), respectively. Response: The RA and PA will ensure that transfer capabilities are established and communicated, according to the functional model. The manner in which this occurs is open. The drafting team believes the standard allows the RA and PA to delegate this function to other entities. Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Gerald Rheault – Manitoba Hydro, S1, S3, S5, S6	Requirements and Measurements – Agree In 606.2.1, "ratings methodology" should be replaced by "transfer capability methodology". Response: Agreed. This correction has been made. Compliance Monitoring Process – Agree In 606.4.4 the phrase "...until the deficiencies resulting in noncompliance" should be changed to "...until the deficiencies

	determined in the findings of non-compliance..." Response: The drafting team agrees. The change has been made. Levels of Non-compliance – Agree
Peter Burke – American Transmission Company, S1	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Kirit Shah – Ameren, S1	Requirements and Measurements – Agree Assuming that the requested transfer capability would be properly defined. Compliance Monitoring Process – Agree Levels of Non-compliance – No. Yes for 5.1 & 5.2. 5.3 - What is ratings methodology has to do with transfer capability? Response: Ratings methodology will be changed to transfer capability methodology. 5.4 – What are transfer capability ratings? Response: Ratings will be removed. It will read "transfer capabilities" not "transfer capabilities ratings".
WECC Technical Studies Subcommittee Peter Mackin – Trans Agency of Northern Calif, S1 Chifong Thomas – Pacific G&E, S1 Esteban Martinez – Turlock Irrigation District, S1 Peter Krzykos – Ariz Public Service, S1 Joe Seabrook – Puget Sound, A1 Phil Park – BC Trans Co, S1 C V Chung – Seattle City Light, S9	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Please add the Transmission Service Provider to the list of functions in 606.4.2 and 606.4.3. Also, please change "which" to "that" in Section 606.4.1. Response: Agreed. The suggested changes have been made. Levels of Non-compliance – Agree We think we agree with the philosophy of increasing penalty from not providing some information, providing wrong information and not providing any information at all. However, this also means that there is no distinction between missing between one limit and most of the limits. This is a disincentive for people to improve compliance. Response: The drafting team debated this issue, reviewed industry comments, and decided that creating penalties based on the number of omissions made the compliance process unnecessarily complicated with little value added.
FRCC OC, EC, MIC Linda Campbell – FRCC, S2 Paul Elwing – Lakeland Electric, S3 John Shafer – FP&L, S1	Requirements and Measurements – No. In 1.1,the inclusion of "NERC and its Regions" causes some concern. There needs to be reasoning or a need to know to supply transfer capability information to NERC and its Regions. This implies that all regions would get capability information from FRCC and we

Don McInnis – FP&L S1 Patti Metro – FRCC, S2 Joe Krupar – FMPA, S3 Richard Gilbert – Lakeland Elect S3 Amy Long – Lakeland Elect S1 Roger Westphal – Gainesville Regional Utilities S5 Bob Remley – Clay Elect Coop S4 Steve Wallace - Seminole Elect Coop S4 Ted Hobson – JEA, S1	are not sure that is necessary. In 2.1 and 2.2 the terms "responsible entities" needs to be more specific. Response: Based on the purpose of the standard, the SDT believes that requests for transfer capabilities will be made when they are necessary for planning and operating the bulk electric system. The standard describes what entities are involved with establishing and communicating transfer capabilities. How that is accomplished is not prescribed by the standard. The use of the term "responsible entities" was discussed with NERC's General Counsel and his opinion was that the use of responsible entities was clear and legally sufficient. The alternative of repeating each entity in each passage would make the standard difficult to follow. Compliance Monitoring Process – No.Same comment as earlier for "either on or off site". Same comment as earlier on the performance reset period. Response: This term has been defined on the first page of the standard. The use of on or off-site compliance reviews will be addressed by the compliance committee when regional compliance programs are developed. Levels of Non-compliance – No. Until we understand why NERC and its Regions should be supplied with the transfer capability, we do not agree with 5.2. Also, we are not sure of the difference between 5.2 and 5.4. Response: NERC and the regions require the capabilities to perform reliability assessments, which is one of NERC's basic functions, for example. Response: Section 5.2 (level 2) noncompliance will occur when some but not all of the requested transfer capabilities are provided. Section 5.4 (level 4) noncompliance will occur when none of the requested transfer capabilities are provided. Would it be clearer to state in 5.2 that some but not all requested transfer capabilities were provided? Response: The suggested change has been made.
Gary Won – IMO S2	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree See general comment below.
William J Smith – Allegheny Power, Segment 1	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Guy Zito, **NPCC CP9** Michael Schiavone – Nat Grid USA, S1	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree

Roger Champagne – HQ Transenergie, S1 Ralph Rufrano – NYPA, S1 David Little – Nova Scotia Power, S1 David Kiguel – Hydro One, S1 Michael Potishnak – ISONE, S2 Barry Gee, Nat Grid USA, S1 Dan Stosick – ISONE, S2 Fernando Saavedra – ISONE, S2 Greg Campoli – NYISO, S2	
Ken Githens – Allegheny Energy Supply – Segment 5	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree
Charles Yeung – Reliant Energy, S5	Requirements and Measurements – No. This section lacks a requirement to post the Transfer Capability values publicly in a manner prescribed by applicable tariffs and FERC Order 889 for jurisdictional entities. Response: The intent of the standard is to ensure transfer capabilities are established and communicated to the entities responsible for operating and planning the bulk transmission system. Processes for posting transfer capabilities publicly is outside the scope of the standard. Consistent with industry consensus developed during the development of the SAR associated with this standard, ATC was not included in this standard. FERC 889 deals with ATC. Compliance Monitoring Process – No response. Levels of Non-compliance – No response.
Kathleen Goodman – ISONE, S2	Requirements and Measurements – Agree Compliance Monitoring Process – Agree Levels of Non-compliance – Agree

12. What additional clarification, details, or modifications to this standard are necessary before it can be brought to ballot?

NERC Transmission Subcommittee Robert Reed – PJM Daniel Cooper – Michigan Public Power Agency Ken Donohoo – ERCOT Michael Gildea – Duke-Energy, North America Francis Halpin – BPA Tom Mallinger – MISO Darrick Moe – WAPA Scott Moore – AEP Bill Slater – Florida Power Corp Tom Stuchlik – Western Resources Joseph Styslinger – Southern Co David Thorne – DH Thorne Consultants Robert Waldele – NYISO	1) "Transfer Capabilities" definition needs enhancement. The first sentence should be broken into two or more sentences. The definition is vague, for example "the measure of the ability." The definition should also contain the difference between TC and ATC. 2) The TS recommends identifying the terms used in the standards that are found in the new Standards Process "Glossary of Terms" repository. The TS suggests small capital letters, highlighted letters, bold letters, italicized letters or other method of making the defined words, terms and acronyms stand out. 3) All of the definitions should e cross-referenced against the Functional Model and other standards to ensure the same term has a consistent definition. Response: The TC definition has been used since 1995 and was vetted during the SAR process. It is not appropriate to define other terms in the definition of TC. Available transfer capability (ATC) is outside the scope of this standard because it was deemed a commercial term during the development of the SAR. Industry consensus dictated that ATC is NOT to be included in this standard. TC is an *input* to the ATC calculation. In response to this and similar comments on other NERC standards, defined terms will now be capitalized in the standards.

Roman Carter – Southern Co John Ahr – Allegheny Power Susan Morris – SERC Ed Pfeiffer – Ameren Ray Palmieri – ECAR	Agree that cross-referencing should occur in this and all NERC standards.
Mark Heimbach – PPL Generation, Segment 5	No suggested changes.
Roman Carter (& 9 other employees) - Southern Company Generation and Marketing, Segments 5,6 Terry Crawley & Roger Green – SOCO Generation, Segment 5	No suggested changes.
R T Sikes (& 4 other employees) – CenterPoint Energy Real Time Operations	We are not sure there is a clear distinction between ratings of equipment and operational limits. Response: The difference is that equipment ratings are one of several inputs into operational limits. For example, an operational limit on a facility may take voltage or stability constraints imposed by the network into consideration, as well as the rating of the equipment.
Alan Johnson – Mirant Americas Energy Mktg, Segment 6	No suggested changes.
SERC Planning Standards Working Group Clay Young – South Carolina Electric & Gas, Segment 3 Byron Stewart – TVA, S1 David Weekly – Municipal Electric Authority of Georgia – S1 Brian Moss – Duke Power, S1 Darrell Pace – Alabama Electric Cooperative, S1 Bob Jones – SoCo, S1 Kham Vongkhamchanh – Entergy, S1 Pat Huntley – SERC, S2	Recommend that a definition be added for "performance-reset period." Response: This term has been defined on the first page of the standard. Footnote "d" to Table I on page 7 is not correct. It appears that the wrong footnote was copied from Table I of NERC Planning Standards I.A. The correct footnote should be the same as footnote "e" to the NPCC Table IA which reads: "Nor mal clearing is when the protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer (CT), and not because of an intentional design delay." Response: The table section of this standard has been modified, in response to this and other comments. The Sanctions Table on page 18 needs further clarification. Examples of its application may be useful. Response: Examples cannot be included in the standard, but are a good idea for a reference document. This comment will be shared with the compliance committee.
SERC Operations Planning Subcommittee Carter Edge – Southeastern Power Administration, S4&S5 William Gaither – South Carolina Public Service Auth, S1 Mike Miller – SoCo, S1 Roger Brand – Municipal Electric Authority of Georgia, S1 Phil Creech – Progress Energy (Carolina), S1	Same comments as SERC Planning Standards Working Group listed above.

Gene Delk & Al McMeekin – South Carolina Electric and Gas, S1 Greg Ott – Alcoa/Yadkin, S1 Doug Newbauer – Georgia System Operations, S1 Mike Clements & Mark Creech – TVA, S1 Don Reichenbach – Duke Energy, S1 Lynna Estep – SERC, S2	
Robert Grover – PPL, S3	No suggested changes.
John Horakh – MAAC, S2	No suggested changes.
David Thorne – PEPCO, S1	No suggested changes.
Todd Lucas & 5 other employees – SoCo Trans Plng, S1 and S3	This standard should not be brought to ballot until the Planning Authority is defined in the Functional Model since the Planning Authority is assigned requirements in this standard**.** Response: The SAC is well aware of this issue. This standard was developed with the belief that the Planning Authority will be included in the functional model when it is finalized.
Lee Westbrook – OnCor, S1	No suggested changes.
Darrel Richardson – Illinois Power, S1 S2	No suggested changes.
Ed Davis – Entergy, S1	No suggested changes.
MAPP Operations Subcommittee Allan Silk – Manitoba Hydro Paul Brune – NPPD Paul Koskela – Minnesota Power Larry Larson – Otter Tail Darrick Moe – WAPA Dick Pursley – Great River Energy Martin Trence – Xcel Energy Todd Gosnell – Omaha PPD Joseph Knight – MAPPCOR, S2	No suggested changes.
Clay Young and 8 employees – South Carolina Electric & Gas, S1, S3, S5	1. Footnote “d” to Table I on page 7 is not correct. It appears that the wrong footnote was copied from Table I of NERC Planning Standards I.A. The correct footnote should be the same as footnote “e” to the NPCC Table IA which reads: “Normal clearing is when the protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer (CT), and not because of an intentional design delay.” 13. The Sanctions Table on page 18 needs further clarification. Response: Please see responses to SERC Planning Group above.
Paul Johnson – AEP, S1,S3,S5, S6	Defined terms must be capitalized, such as “Reliability Authority”, “Facility Rating”, “System Operating Limit”, “Planning Authority”, etc. Response: In response to this and similar comments on other standards, defined terms will now be capitalized in NERC standards.
Dilip Mahendra – SMUD, S1	No suggested changes.
James Spearman & Florence Belser	No suggested changes.

– PSC of S. Carolina, S9	
SPP Operating Reliability WG Gerry Burrows – KCP&L, S1 Bob Cochran – SPS, S1 Peter Kuebeck – OG&E, S1 Scott Moore – AEP, S1 Dan Boezio – AEP, S1 Tom Stuchlik – Westar, S1 Matt Bordelon – CLECO, S1 Mike Crouch – WFEC, S1 Mike Gammon – KCP&L, S1 Kevin Goolsby – SPP, S2 Bo Jones – Westar, S1 Allen Klassen – Westar, S1 Thad Ness – AEP, S1 Harold Wyble – KCP&L, S1 Robert Rhodes – SPP, S2	No suggested changes.
John Blazekovich - Exelon, S1,S3,S5,S6	No suggested changes.
Raymond Mammarella – PPL, S1	No suggested changes.
Carter Edge – S.E. Power Admin, S4, S5	Same comments as SERC Planning Standards Working Group listed above. Response: See above.
Tom Pruitt & 4 other employees – Duke Power, S1 & S5	No suggested changes.
Alan Boesch – NPPD, S1	In section 601,602, 603,604, 605 and 606 the requirement is to document the methodology, include the criteria to not exceed ratings and include assumptions. The measurements should reflect the requirements and the levels of non-compliance should reflect the measures. Failure to provide the documentation within a prescribed time limit is a compliance issue that should be addressed by the compliance program This standard seems to be overly concerned with receiving data on time. Response: The team agrees that the time limits are a compliance issue, to be handled via the compliance program. The NERC standards must specify the criteria to be used in the compliance process, as dictated by the NERC standards development manual. Requirements state the desired outcome; the time for accomplishing these outcomes is part of the measures. The time frame should provide ample time for an entity to respond with existing documentation. Measurements reflect the metrics used to measure compliance to the requirements, but are not a one-for-one translation of the requirements.
Tony Jankowski – We Energies, S4	1) Management of compliance matrix with the philosophy of no financial for documents only communication of limits. Response: The standard supports this comment, as written. 2) Requirement 603 Table I needs to be consistent within an interconnection – no regional difference. Response: Regions have the right to request differences, even if they do not apply to the entire interconnection as described in the standards process manual. The industry has the opportunity to comment and ultimately vote on any proposed Regional difference. 3) Only one function responsible for developing SOL's and transfer capabilities.

	Response: This suggestion is in conflict with the functional model, which is the foundation of the standards. The functional model assumes that the determination of SOLs and transfer capabilities must be coordinated among the identified functions. In actual practice, it may be a single entity that performs all of the functions. The actions assigned to each function must be debated in the development of that document.
Don Chandler – CenterPoint, S1	No suggested changes.
Tom Mielnik – MidAmerican, S3	The table providing the sanctions on page 18 requires some interpretation on the part of the reader. This table should be clarified. If possible, give some examples of what sanction applies for when to help the reader follow this table. Response: Examples cannot be included in the standard, but are a good idea for a reference document.
Michael Sidiropoulos – Pacificorp, S1	No suggested changes.
Mitchell Needham – TVA, S1 Gary L. Jackson – TVA, S6 Mark Creech – TVA	No suggested changes.
Mike Viles & 9 other employees – BPA Transmission, S1	No suggested changes.
Carey Gates – CalISO, S2	The standard should note in the "Purpose" that it is not the intent of the standard to "standardize" methodologies of determining ratings but to document and make available the individual methodologies that were used. Response: The standard does not require the use of single methodology by all those responsible for determining ratings, nor is it the intent of the standard. This was done specifically in response to industry consensus during the SAR drafting. The Purpose focuses on what the reliability need for the standard, as opposed to what it does not do.
Susan Morris – SERC, S2 Bill Reinke – SERC, S2 Sam Stryker – Fayetteville PWS, S3, S4, S5 John Stickley – AECI, S1 Carter Edge – SEPA, S4,S5 John Troha – SERC, S2 Tim Ponseti – TVA, S1 Bill Thompson – Dominion Transmission, S1	1. Recommend that a definition be added for "performance-reset period." 2. Footnote "d" to Table I on page 7 is not correct. It appears that the wrong footnote was copied from Table I of NERC Planning Standards I.A. The correct footnote should be the same as footnote "e" to the NPCC Table IA which reads: "Normal clearing is when the protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer (CT), and not because of an intentional design delay." 3. The Sanctions Table on page 18 needs further clarification. Examples of its application may be useful. Response for 1-3: Please see previous response to same SERC comments. 14. The SDT should consider modifying 601 and 602 to require that there be consistency in the ratings and the rating methodology. Not consistency from facility to facility, since there are so many variables among facilitites, but consistency in ratings from submission to submission. In other words, the planning and/or emergency rating of a facility should be the same whether NERC is asking, or FERC, the State Utilities Commission, a neighboring utility, an IPP, or a marketing participant. Response: The standard is intended to require that ratings methodologies be applied consistently, as suggested by this comment. A NERC standard cannot impose requirements associated with data submittals to parties outside NERC, however.

Gerald Rheault – Manitoba Hydro, S1, S3, S5, S6	No suggested changes.
Peter Burke – American Transmission Company, S1	There are places within this draft standard that imply, for instance, that a thermal overload is not a violation if it does not lead to cascading outages or instability. Generally, shouldn't it be true that an overload is a violation of a limit regardless whether that leads to more serious consequences - that this standard should focus on how limits are calculated without regard to how the system operates? Response: The purpose has been revised to add greater clarity. It appears that this proposed standard will apply NERC Table I, Category A and B criteria from the original Planning Standards to whatever the current operating condition is at the time. In other words, a prior outage condition (category B by Planning standards) now becomes the category A, normal condition, in preparing the system to meet the next contingency. We need to be sure that the footnotes under the "Loss of Demand or Curtail Firm Transfers" column allow operators to shed firm load and firm transfers under appropriate conditions. Footnote b attempts to do this for category B, but it's not certain whether it covers all our concerns under the Category A or B conditions that the system might be in at any given time. The Table I in the original Planning Standards did provide for planned shedding of firm load/transfers to meet criteria under Category C (N-2+) conditions. Also, the draft standard does not make certain that after the system experiences a category B event, operations must adjust to handle the next event under category B criteria, instead of the category C based on Planning criteria. Response: Agreed. After a contingency occurs, the limits should be reviewed and recalculated, if necessary. The table section of the standard has been revised. Finally, it looks like footnote d was intended to have the wording from footnote e in NPCC's table I instead of the existing wording and that footnote d needs to be added everywhere "Normal Clearing" shows up in the table. Response: The table section of the standard has been revised.
Kirit Shah – Ameren, S1	Under Compliance Monitoring Process - "Verified at any time as the result of a complaint" should be modified to include who can complaint? Therefore, suggest modification as "Upon complaint from the reliability authority, planning authority, or transmission operator, the compliance monitor will assess the responsible entity's performance under this requirement by information submittal, either on or off site." Response: This section of each requirement has been revised in response to this comment.
WECC Technical Studies Subcommittee Peter Mackin – Trans Agency of Northern Calif, S1 Chifong Thomas – Pacific G&E, S1 Esteban Martinez – Turlock Irrigation District, S1 Peter Krzykos – Ariz Public Service, S1 Joe Seabrook – Puget Sound, A1 Phil Park – BC Trans Co, S1 C V Chung – Seattle City Light, S9	No suggested changes.
FRCC OC, EC, MIC Linda Campbell – FRCC, S2 Paul Elwing – Lakeland Electric, S3 John Shafer – FP&L, S1	In the comment box on this first page, the SDT has stated that the terms RA, PA etc really apply to the entities performing the functions identified in the functional model. We understand and appreciate why the team did this, however, there is still a lot of confusion about functions vs entities in the functional model. We would

Don McInnis – FP&L S1 Patti Metro – FRCC, S2 Joe Krupar – FMPA, S3 Richard Gilbert – Lakeland Elect S3 Amy Long – Lakeland Elect S1 Roger Westphal – Gainesville Regional Utilities S5 Bob Remley – Clay Elect Coop S4 Steve Wallace - Seminole Elect Coop S4 Ted Hobson – JEA, S1	suggest that the standard include the extra words to make this distinction. Response: The drafting team wholeheartedly agrees, and has made every effort to make this distinction. In the applicability paragraph, the SDT has referenced the functional model approved by the BOT in June 2001. This reference causes concern. We understand that including this reference and date identifies the version of the functional model so that the understanding of the functions are based on this particular document. But, what happens when the BOT approves a change to the model at a later date? Do we now have standards based on one set of functions or understanding of functions that are different than what is in the latest functional model? This will certainly cause confusion in the industry. But, on the other hand, if you remove the date reference, then anytime the BOT changes the model, they are effectively changing the standard without going through the SAR process. We do not want the BOT to be able to change who the standards apply to without going through due process either. How do we deal with this situation? Response: The applicability section has been modified in response to this comment. We concur that the functional model and standards must remain in synch, but the drafting team does not have the authority to modify the model.
Gary Won – IMO S2	All the sanctions text should be removed, as they are dealt with elsewhere. Response: The NERC standards process requires that sanctions be explicitly listed in the standard so that those voting have full knowledge of the compliance portion of the standard.
William J Smith – Allegheny Power, Segment 1	No suggested changes.
Guy Zito, **NPCC CP9** Michael Schiavone – Nat Grid USA, S1 Roger Champagne – HQ Transenergie, S1 Ralph Rufrano – NYPA, S1 David Little – Nova Scotia Power, S1 David Kiguel – Hydro One, S1 Michael Potishnak – ISONE, S2 Barry Gee, Nat Grid USA, S1 Dan Stosick – ISONE, S2 Fernando Saavedra – ISONE, S2 Greg Campoli – NYISO, S2	No suggested changes.
Ken Githens – Allegheny Energy Supply – Segment 5	No suggested changes.
Charles Yeung – Reliant Energy, S5	No suggested changes.
Kathleen Goodman – ISONE, S2	No suggested changes.

13. Please enter any other comments you have regarding this standard in the space below.

R T Sikes (& 4 other employees) – CenterPoint Energy Real Time Operations	We believe that operation in regards to limits, real-time, is a coordinated effort between Reliability Authority and Transmission Operator. Response: This does not conflict with this standard. This standard does not address operation within limits, but rather the determination of the limits.
Robert Grover – PPL, S3	Methodologies, Procedures and Processes may be better handled within the Certification Process than with the Standards Process. The reason being is that such documentation should be created before any applicant is allowed to operate

	within NERC. Response: Certification will only determine whether an entity is capable of performing a given function. This standard specifies what the entity performing the function must do. There is a need to include the methodologies in this standard to ensure that the most current version is being used for determining the limits and ratings. It is not clear at this time that all functions identified in this standard will be certified by NERC.
John Horakh – MAAC, S2	Same comment as Robert Grover, PPL, above.
David Thorne – PEPCO, S1	Same comment as Robert Grover, PPL, above.
Todd Lucas & 5 other employees – SoCo Trans Plng, S1 and S3	The phrase "for the areas for which they are responsible" appears several times in this standard. We assume this is a reference to the responsibilities assigned in the functional model definitions. We believe it would be helpful if the areas of responsibility for each entity that are covered by this standard were re-stated within the standard. Response: This is a good point. When all the NERC standards are completed, the functional model will be attached to them as a reference document. The drafting team does not believe it is appropriate to repeat the functional model in every standard.
Ed Davis – Entergy, S1 Susan Morris – SERC, S2 Bill Reinke – SERC, S2 Sam Stryker – Fayetteville PWS, S3, S4, S5 John Stickley – AECI, S1 Carter Edge – SEPA, S4,S5 John Troha – SERC, S2 Tim Ponseti – TVA, S1 Bill Thompson – Dominion Transmission, S1	We are becoming increasingly concerned about this standard development process. This and other standards are being developed based on certain definitions and assumptions contained in the Function Model. These "standards" will become fixed such that the industry will be held accountable to and measured by these standards. However, the Functional Model and the definitions contained in that revised model are changing and will not necessarily be the same as those used to develop the standards, like this Operate Within Limits. What is the process for reviewing, revising and implementing changes to the Functional Model, and the impact of those changes on all these standards that have been developed based on the old Functional Model? Are the changes to the Functional Model being vetted by all industry participants before implementation? What is the process to revise these standards prior to implementing changes to the Functional Model? Response: The applicability section has been modified in response to this comment. We concur that the functional model and standards must remain in synch, but the drafting team does not have the authority to modify the model.
Paul Johnson – AEP, S1,S3,S5, S6	Penalties for non-compliance are not comparable between this Standard and the Operate within Interconnection Reliability Operating Limits Standard. Response: This commenter was contacted and he does not wish to make any changes to this standard in this area, but rather just makes the observation. The SAC has asked the NERC compliance and certification committee to review all NERC standards to ensure consistency in the penalties associated with them.
SPP Operating Reliability WG Gerry Burrows – KCP&L, S1 Bob Cochran – SPS, S1 Peter Kuebeck – OG&E, S1 Scott Moore – AEP, S1 Dan Boezio – AEP, S1 Tom Stuchlik – Westar, S1 Matt Bordelon – CLECO, S1 Mike Crouch – WFEC, S1 Mike Gammon – KCP&L, S1 Kevin Goolsby – SPP, S2 Bo Jones – Westar, S1 Allen Klassen – Westar, S1 Thad Ness – AEP, S1	The performance reset period of one calendar year in 601, 602, 603, 604, 605 and 606 should be changed to 12 months. Response: Agreed. The standard has been changed as suggested. Penalties for non-compliance do not appear to be consistent between this SAR and SAR 200, Operate Within Interconnection Reliability Operating Limits. There should be consistency among all standards. Response: The SAC has asked the NERC compliance and certification committee to review all NERC standards to ensure consistency in the penalties associated with them.

Harold Wyble – KCP&L, S1 Robert Rhodes – SPP, S2	
Alan Boesch – NPPD, S1	The Purpose of the Standard as currently written says" operate the bulk electric system within predefined facility and operating limits such that cascading outages, uncontrolled system separation, and voltage and transient instability are avoided." This is the definition of an IROL. IROLs are a subset of all the System Operating Limits. The Purpose should be re-worded to include all System Operating Limits. Response: The Purpose has been revised in response to this comment. The Applicability section should define who is responsible and not use words like "such as". Response: The drafting team believe the sections of the standard clearly identify which functions the standard applies to. The applicability section is intended as a bridge until entities are certified to perform those functions.
Don Chandler – CenterPoint, S1	We believe the operations within the limits should be a coordinated effort in Real Time between the Reliability Authority and the Transmission Operator. This Standard does not appear to express that. We agree with the owners of the equipment setting the ratings, but we are not clear on the definitive line between ratings and limits. We do not believe that clarity is in this Standard. We believe any discussion on limits should be coordinated with the Planning Authority, Reliability Authority and Transmission Operator. We are not sure this is brought forward in this Standard. Response: Operations within limits is addressed in a separate standard. This standard requires that the RA ensure that limits are determined for real time operation. The RA can coordinate or delegate this activity, but remains responsible. Equipment ratings are one of several inputs into system operatiing limits. For example, an operational limit on a transmission path (or flow gate) may take voltage or stability constraints imposed by the network into consideration, as well as the rating of the equipment.
Mike Viles & 9 other employees – BPA Transmission, S1	It is suggested to add a couple of examples to work through for the Sanctions Tables. It would make it easier to understand how the Tables work together. Titles for the sanction tables are suggested. Response: A reference paper to help interpret the sanction tables will be requested from the compliance group.
Gerald Rheault – Manitoba Hydro, S1, S3, S5, S6	Manitoba Hydro offers the following general comments relative to this Standard: - There is a requirement to address coordination between connected Reliability Authority areas in determining Transfer Capability which is not included in this standard. What if the connected entities responsible for determining Transfer Capability use different methodologies and disagree on the Transfer Capability? Coordination raises many difficult issues and not addressing it will leave a gap in procedure to achieve reliability. This concern should be addressed in this Standard or another Standard to be developed in parallel to this one. It should not be left up to the parties to work out themselves but should be defined in a Standard. - Response: A separate standard ("Coordinate Operations") is being developed specifically to address coordination between reliability authorities. The connected entities will only need to agree on the magnitude of the Transfer Capability, but the standard allows for differences in methodology.

	- This Standard is successful in addressing the scope defined by the SAR. The overall structure should promote reliability provided equipment ratings and operating limits are valid. However, the approach contained in this standard raises concerns about its effectiveness to meet the stated purpose in 600.1 The main teeth in the document to achieve valid operating limits are in Table 1. System studies are not applied consistently in the industry. Requirement 603.1.3 by itself would promote more consistent application of studies. However, this step forward is thwarted by the definition of "System Operating Limit" which says "as determined through system studies and/or operational experience." There is very little requirement regarding the content of the methodologies (except Table 1). This is probably to avoid forcing the expenditure of resources (studies, staff, and tools) without justification. As a result, reliability will still depend on the momentum of "good industry practice", i.e., the mindset of those individuals responsible for reliability and their ability to influence the rest. Depending on the "teeth" left in the standard (as a legal document), it may only be good for preaching to the choir. I sense the choir is thinning out these days relative to the congregation. Response: The drafting team understands this point. The standard attempts to remain true to NERC's mission to develop standards aimed towards performance objectives as opposed to prescriptive "how to" rules. There is a SAR related to disturbance analysis that may serve useful as a feedback loop to measure the effectiveness of these standards. A NERC standard is a form of legal document – it spells out the standards, the measurements, the levels of compliance and the penalties for non-compliance. As such, there should be no ambiguity, so any term defined by NERC should be clearly identified in the standard (capitalized, bold, etc.) where it is used as a defined term, or NERC must certify that all uses of a defined word are a reference to the defined term. Response: In response to this and other similar comments on other standards, defined terms will now be capitalized in NERC standards.
WECC Technical Studies Subcommittee Peter Mackin – Trans Agency of Northern Calif, S1 Chifong Thomas – Pacific G&E, S1 Esteban Martinez – Turlock Irrigation District, S1 Peter Krzykos – Ariz Public Service, S1 Joe Seabrook – Puget Sound, A1 Phil Park – BC Trans Co, S1 C V Chung – Seattle City Light, S9	(1) The language used in the compliance document could be written in more "userfriendly" language. (2) We would prefer to see several tables summarizing the "Compliance Monitoring Process". The tables should be in plain English stating clearly self certification, how long to hang on to the records, sample of documents to be saved, how long after announcement of audit would we expect to produce the records, how often to refresh the records (performance-reset period?), will each utility receive a reminder?, etc. Response: The implementation plan associated with each standard will provide additional detail related to compliance assessment. The compliance portion of the standard is intended to be at a high level. These comments have been forwarded to the compliance committee.
FRCC OC, EC, MIC Linda Campbell – FRCC, S2 Paul Elwing – Lakeland Electric, S3 John Shafer – FP&L, S1 Don McInnis – FP&L S1	We think the name of the standard along with the number should always be referenced on the web site, emails etc. It will be hard to remember just by the number. Response: The drafting team understands this point. However, when the standards are finalized, they will available in an electronic database that should

Patti Metro – FRCC, S2 Joe Krupar – FMPA, S3 Richard Gilbert – Lakeland Elect S3 Amy Long – Lakeland Elect S1 Roger Westphal – Gainesville Regional Utilities S5 Bob Remley – Clay Elect Coop S4 Steve Wallace - Seminole Elect Coop S4 Ted Hobson – JEA, S1	address this concern.
Gary Won – IMO S2	The proposed non-compliance levels for all these standards do not follow a natural progression. They seem to be somewhat contrived and slotted into the 4 levels. Response: The philosophy of the team relative to non-compliance levels was explained in the comment form. Is there an improvement the commenter can suggest? 601.4.2.2 - 10 years seems rather infrequent. Should provide opportunity for some verification when ratings change. Response: These are intended as minimum requirements. Some ratings may change daily, which would make the suggested verification philosophy unreasonable. 601.4.3, 602.4.4, 604..4.4, 606.4.4 - 3 years may not be long enough, given the typical timelines required to resolve differences. Response: The compliance monitor data retention requirement has been removed. 603 Table I Note a) – reference is made to NERC Planning Standards – Will these still exist after the new family of standards are in place. Response: The table section has been re-written to add greater clarity. 603 Table IA – The NERC standard permits this table to be included here, but is it really necessary to have it here, other than for information purposes. At the NERC level, would it be sufficient to just note that NPCC has more stringent criteria and refer the reader to the NPCC standards. – In the 2nd row, for "Cascading outages", superscript "f" should be "c". Under category C, for "Double Circuit Tower" (item #3) superscript "e" should be "f" – Note "e" text requires reformatting to remove blank line. Response: The table section has been re-written to add greater clarity. If a Region requests a difference, it must be specifically listed.
Guy Zito, **NPCC CP9** Michael Schiavone – Nat Grid USA, S1 Roger Champagne – HQ Transenergie, S1 Ralph Rufrano – NYPA, S1 David Little – Nova Scotia Power, S1 David Kiguel – Hydro One, S1 Michael Potishnak – ISONE, S2 Barry Gee, Nat Grid USA, S1	Throughout Standard 600, in Sections 601.2.1, 601.5.4, 603.2.1, 603.5.4, 605.2.1 and 605.5.4, it is stipulated that documentation in response to the various requests contained therein must be made "• w ithin 15 business days of receipt • ." This time period seems to be arbitrarily chosen and is certainly unreasonably short and NPCC suggests a minimum of 20 business days. Response: The 15 business day requirement was included based upon the team's assumption for a reasonable amount of time to supply documentation that should be on file. The 15 days is intended to allow time for an entity to respond to a request considering the realities of staff availability and internal approval and communications processes NPCC is adamantly opposed to monetary sanctions and feels letters of increasing

Dan Stosick – ISONE, S2 Fernando Saavedra – ISONE, S2 Greg Campoli – NYISO, S2	severity are a more effective compliance tool for ensuring adherence to standards. Response: The drafting team respects NPCC's opinion. However, NERC reserves the right to levy financial sanctions, where appropriate, for violations of its standards. Such sanctions would be identified in the proposed standard and would be applied if the industry supported them. This comment will be shared with NERC's General Counsel and Director of Compliance.
Ken Githens – Allegheny Energy Supply – Segment 5	RA data collection and communication is required under Std. 200 and 600 with financial sanction for noncompliance under both. An organization should not be hit with financial sanctions under both standards for not communicating the data. Only one standard should apply. Response: The drafting team agrees that there should be no double jeopardy. The data required in the two standards is different, though, so none is believed to exist.
Kathleen Goodman – ISONE, S2	Throughout Standard 600, in Sections 601.2.1, 601.5.4, 603.2.1, 603.5.4, 605.2.1 and 605.5.4, it is stipulated that documentation in response to the various requests contained therein must be made "••• within 15 business days of receipt •••." This time period seems to be arbitrarily chosen and is certainly unreasonably short; ISO-NE suggests a minimum of 20 business days. ISO-NE is adamantly opposed to monetary sanctions and believes letters of increasing severity are a more effective compliance tool for ensuring adherence to standards. Response: The drafting team respects ISO-NE's opinion. However, NERC reserves the right to levy financial sanctions, where appropriate, for violations of its standards. Such sanctions would be identified in the proposed standard and would be applied if the industry supported them. This comment will be shared with NERC's General Counsel and Director of Compliance.

Comment Form – 1st Posting of the draft 'Determine Facility Ratings, System Operating Limits, and Transfer Capabilities' Standard

Note – This form is to be used to comment on version 1 of the Determine Facility Ratings, System Operating Limits, and Transfer Capabilities Standard.

Comments will be accepted from July 1 – August 29, 2003.

Please review the draft standard and answer the questions in the yellow boxes. Send completed comment forms to sarcomm@nerc.com

If you have questions, please call Tim Gallagher at 609-452-8060 or send a question to timg@nerc.com

SAR Commenter Information (For Individual Commenters)	
Name	Robert W Waldele
Organization	New York Independent System Operator, Inc
Industry Segment # 2	
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Key to Industry Segment #'s:

1 – Trans. Owners
2 – RTO's, ISO's, RRC's
3 – LSE's
4 – TDU's
5 - Generators
6 - Brokers, Aggregators, and Marketers
7 - Large Electricity End Users
8 - Small Electricity Users
9 - Federal, State, and Provincial Regulatory or other Govt. Entities

SAR Commenter Information (For Groups Submitting Group Comments)		
Name of Group:	**Group Representative:** **Representative Phone:** **Representative Email:**	
List of Group Participants that Support These Comments:		
Name	**Company**	**Industry Segment #**

Background Information:

Notes to Industry Commenters:

The standard drafting team (SDT) considered the SAR for this proposed standard as well as the SAR comments previously supplied by the industry community while developing the standard. The SDT believes that it is helpful for the industry to understand the perspective of the SDT while reviewing this draft standard. The SDT also believes that it would be helpful to explain the linkages with other standards currently under development. The explanations below are offered to provide context and facilitate industry comments.

General Philosophy:

The SDT addressed the three components of this draft standard in three sets of pairs: Facility Ratings (601, 602), System Operating Limits (603, 604), and Transfer Capabilities (605,606). In

each of these pairs, the draft standard requires the development and availability of a "methodology" to determine the required quantities and secondly the application of this methodology in the establishment and communication of these values to the users of the values. These standards were developed assuming that the Facility Ratings, System Operating Limits and Transfer Capability values are to be provided to the user (e.g. those entities performing the reliability authority, planning authority, and transmission operator functions) on a schedule established by the *user*. The SDT endeavored to ensure that this draft standard would not require the determination of various values that had no identified user. For this reason, the user of the various values must request the specific values from the value provider (e.g. those entities performing the facility owner and planning authority functions) through the establishment of a schedule to supply the data.

Levels of Noncompliance:
In the three 'methodologies' sections (601, 603, 605), the levels of noncompliance are based upon the availability and completeness of the documented procedures. In the three 'communication' sections (602, 603,605), the levels of noncompliance are based on the availability of the values *requested by the users* of the information and the consistency of these values with the documented methodologies.

Sanctions:
The SDT believes that failure to comply with the three 'methodologies' sections (601, 603, 605) does not warrant monetary sanctions, since the methodologies themselves would not *directly* impact the reliable operation of the transmission system.

The unavailability of Facility Rating *values*, System Operating Limit *values* and to a lesser extent, Transfer Capability *values* will have a real and detrimental impact on the real time reliability of the transmission system as well as the validity of transmission plans for future transmission system additions. Therefore, the three 'communication' sections (602, 604, 606) include monetary sanctions for repeated and/or significant noncompliance as per the sanction table. The SDT believes that nominal, fixed dollar sanctions are appropriate in these cases. The application of 'per MW' variable sanctions would be inappropriate for these infractions compared to the consequences of violating the requirements of the standard. While the SDT realizes that a minor omission of a requested value could result in sanction, the SDT also believes that graduated sanctions based upon the level of 'completeness' of the data received by the users are impractical. The SDT is of the opinion that not all values have equal importance to the reliability of the transmission system, and therefore, sanctions based upon 'percentage of requested data received' (perhaps omitting values of specific critical limitations) would be arbitrary.

Relationship with "Operate Within Limits" Standard:
The SDT suggests that this draft standard be reviewed in concert with the "Operate Within Limits" draft standard. The Facility Ratings, System Operating Limits, and Transfer Capabilities draft standard requires the availability and usability of these data. The Operate Within Limits standard addresses the use of a subset of these values in real time operation. The SDT believes that the definitions developed in conjunction with this standard do not prohibit the stratification, or sub-classification, of the requested data (Facility Ratings, System Operating Limits, Transfer Capabilities) for specific uses or users. The intent and purpose of this standard, however, is to identify *all* system operating limits and not to differentiate them based upon the impacts of violating them.

1. **This standard assumes that the reliability authority has the ultimate responsibility to establish system operating limits and relies upon the transmission operator for input. Have the roles and responsibilities of transmission operators versus reliability authorities in determining system operating limits been properly characterized in this standard?**

☒ Yes

☐ No

Comments

2. **Do you agree that identifying and communicating all system operating limits is within the scope of this standard and is necessary for reliability?**

☒ Yes

☐ No

Comments

3. **NERC Regions have the right to ask for Regional differences for inclusion in NERC standards. Such differences would apply only to the listed Region and would become an enforceable part of the NERC standard only if approved by the industry. NPCC has requested a Regional difference in section 603. Do you think NPCC's Regional difference should be included in this standard**?

☐ Yes

☒ No

Comments: We had originally interpreted this "Regional Differences" issue as providing for a Region (or Area) to design/operate to a less stringent criteria/standard than the NERC requirement. The process would allow for adjacent Regions/Areas to be made aware of possible inter-Regional/Area adverse impact. The inclusion of the NPCC Criteria as a Regional Difference raises the concern that the NPCC standard is, in effect being balloted by the NERC stakeholders.

Please qualify the intent of the "Regional Differences" – does this mean that NPCC cannot enforce a stricter standard UNLESS it is specifically detailed in the NERC standard, and therefore, approved by the NERC stakeholders, and they have the final say in what/whether NPCC (or any other Region) can enforce a stricter standard? Does inclusion of the NPCC rule in the NERC standard then make the NPCC rule enforceable by NERC? The individual Regions should enforce their own (stricter) rules; where a Region is requesting waiver of a NERC rule (that is thought to be "too strict" on a "regional difference" basis) that should be documented and the appropriate approval sought.

Alternatively, is it appropriate that the "industry" approve a Regional difference? In the specific case, the referenced NPCC rules recognize the higher reliability standard that the NPCC Areas design and operate to in that part of the Interconnection.

Response: If a Region has a less stringent criteria/standard than that in the NERC standard and wishes to be held only to this less stringent criteria, it must request a Regional Difference and

include it in the NERC standard. The entire ballot pool will decide whether to approve the difference when they cast their vote. If a Region has a more stringent criteria/standard, it is not required that this be included in the NERC standard, unless the Region desires to have NERC compliance and enforcement behind the more stringent criteria. If included in the standard, the entire ballot pool will have a say in whether the difference is approved for inclusion in the standard when they cast their vote. If the difference is not approved by the ballot pool as part of the standard, the Region may still implement its more stringent criteria in its own compliance program as it sees fit.

The Regional Difference concept was discussed with NPCC and the drafting team was informed that NPCC desires to include their more stringent criteria as a difference in this standard.

4. Are you aware of any other Regional differences that should be included in this standard?

☐ Yes

☒ No

Comments

5. Do you agree with the sanction philosophy in this standard? (No financial penalties for methodology violations, nominal fixed monetary penalties for failure to communicate values).

☐ Yes

☒ No

Comments: We disagree with the imposition of monetary sanctions as it has not been demonstrated to be an effective means of achieving compliance. Placing a financial penalty on the communication seems to relegate the method (accuracy of data and analysis) to secondary status.

Response: The drafting team respects this position. However, NERC reserves the right to levy financial sanctions, where appropriate, for violations of its standards. Such sanctions would be identified in the proposed standard and would be applied if the industry supported them. The drafting team is concerned that the industry may feel that eliminating financial sanctions will be perceived as reducing the significance of the violations. The drafting team welcomes suggestions to better structure the overall sanction philosophy. This comment will be shared with NERC's General Counsel and Director of Compliance.

6. Do you agree with the proposed requirements and measurements in section 601?

☒ Yes

☐ No

Comments

7. Do you agree with the proposed compliance monitoring process in section 601?

☒ Yes

☐ No

Comments

8. Do you agree with the proposed levels of non-compliance in section 601?

☒ Yes

☐ No

Comments

9. Do you agree with the proposed requirements and measurements in section 602?

☒ Yes

☐ No

Comments

10. Do you agree with the proposed compliance monitoring process in section 602?

☒ Yes

☐ No

Comments

11. Do you agree with the proposed levels of non-compliance in section 602?

☒ Yes

☐ No

Comments: We disagree with the imposition of monetary sanctions as it has not been demonstrated to be an effective means of achieving compliance.

Response: The drafting team respects this position. However, NERC reserves the right to levy financial sanctions, where appropriate, for violations of its standards. Such sanctions would be identified in the proposed standard and would be applied if the industry supported them. The drafting team is concerned that the industry may feel that eliminating financial sanctions will be perceived as reducing the significance of the violations. The drafting team welcomes suggestions to better structure the overall sanction philosophy. This comment will be shared with NERC's General Counsel and Director of Compliance.

12. Do you agree with the proposed requirements and measurements in section 603?

☐ Yes

☒ No

Comments: Should clarify references to the "interruption of load" in f/n (b). Uncomfortable with the internalized definition of "cascading." F/n (d) is not referenced in the Table 1 – appears to be a hold over from the "old policy" (P2.A.1.1) stating "Multiple outages of credible nature…shall also be examined and Control Areas shall operate to protect against…" – this clearly suggests that the design and operating philosophy is being severely weakened.. The use of the term "single element" outage can easily be mis-interpreted to imply only single circuit, or one branch of a multiple element (i.e., 3-terminal facility) – this should more correctly be stated as "single contingency event of all elements within a single protection zone." We are also very concerned that the standard has removed any reference to the consideration of consideration for double-circuit tower, or breaker failure or SLG-delayed clearing contingencies.

Response: This section of the standard has been re-written in response to industry comments. Please review the revised version and let the drafting team know if your concerns have not been adequately addressed.

13. Do you agree with the proposed compliance monitoring process in section 603?

☒ Yes

☐ No

Comments

14. Do you agree with the proposed levels of non-compliance in section 603?

☒ Yes

☐ No

Comments

15. Do you agree with the proposed requirements and measurements in section 604?

☒ Yes

☐ No

Comments

16. Do you agree with the proposed compliance monitoring process in section 604?

☒ Yes

☐ No

Comments

17. Do you agree with the proposed levels of non-compliance in section 604?

☒ Yes

☐ No

Comments: We disagree with the imposition of monetary sanctions as it has not been demonstrated to be an effective means of achieving compliance.

Response: The drafting team respects this position. However, NERC reserves the right to levy financial sanctions, where appropriate, for violations of its standards. Such sanctions would be identified in the proposed standard and would be applied if the industry supported them. The drafting team is concerned that the industry may feel that eliminating financial sanctions will be perceived as reducing the significance of the violations. The drafting team welcomes suggestions to better structure the overall sanction philosophy. This comment will be shared with NERC's General Counsel and Director of Compliance.

18. Do you agree with the proposed requirements and measurements in section 605?

☐ Yes

☒ No

Comments: Not clear what the intent of 605.1.2: "transfer capabilities shall adhere to all applicable system operating limits." How can this be measured?

Response: The intention is that when transfer capabilities are established, system operating limits must be considered. A transfer capability must not result in system operating limits being exceeded. A compliance review of the process used for determination of transfer capability will reveal if transfer capability values respect system operating limits.

19. Do you agree with the proposed compliance monitoring process in section 605?

☒ Yes

☐ No

Comments

20. Do you agree with the proposed levels of non-compliance in section 605?

☒ Yes

☐ No

Comments

21. Do you agree with the proposed requirements and measurements in section 606?

☐ Yes

☒ No

Comments: Is there a limit to the amount of information that "NERC and its Regions" would be requesting in the context of "transfer capabilities?" or does this apply to the reporting of inter-Regional transfer capabilities only? Need a better definition of "transfer capability" -- is it related to ATC/TTC or TSC?

Response: The amount of information is left to the discretion of those who request it. The standard does not prescribe this. Both inter and intra-regional transfer capabilities may be requested. Transfer capability is not the same as ATC or TTC, but can be related. ATC was considered to be a commercial quantity by industry commenters and consensus was that it not be included in the standard when the SAR associated with this standard was developed.

22. Do you agree with the proposed compliance monitoring process in section 606?

☒ Yes

☐ No

Comments

23. Do you agree with the proposed levels of non-compliance in section 606?

☒ Yes

☐ No

Comments: Assumes that the extent of the reporting requirement applies to inter-Regional transfer capabilities. We disagree with the imposition of monetary sanctions as it has not been demonstrated to be an effective means of achieving compliance.

Response: The drafting team respects this position. However, NERC reserves the right to levy financial sanctions, where appropriate, for violations of its standards. Such sanctions would be identified in the proposed standard and would be applied if the industry supported them. The drafting team is concerned that the industry may feel that eliminating financial sanctions will be perceived as reducing the significance of the violations. The drafting team welcomes suggestions to better structure the overall sanction philosophy. This comment will be shared with NERC's General Counsel and Director of Compliance.

24. What additional clarification, details, or modifications to this standard are necessary before it can be brought to ballot?

Comments: Has the drafting team considered the volume of support documentation that is being requested in the initial compliance effort? This reporting requirement may place a significant burden on the RA, etc., and the compliance monitor. Need enhanced definitions of transfer capability and clarification of the regional differences application.

Response: Please see earlier response to Regional Difference question. The drafting team has carefully considered the amount of documentation required, but has stopped short of specifying the appropriate amount in the standard, choosing rather to leave it to the discretion of those involved.

25. Please enter any other comments you have regarding this standard in the space below.

Comments: In addition to the response to #24 above, we are genuinely concerned that this document clearly represents a weakening of the overall design and operating philosophy for interconnected system operation and (now more clearly after August 14) NOT the direction that NERC or the industry should be taking.

Response: Please review the modifications made to the table of expected performance to see if you still feel the same way. The requirements are based very much upon previous planning standards.