Consideration of Comments

Project Name: 2010-14.2.1 Phase 2 of Balancing Authority Reliability-based Controls | BAL-005-1, BAL-006-3 & FAC-001-3

Comment Period Start Date: 7/30/2015

Comment Period End Date: 9/14/2015

Associated Ballot: 2010-14.2.1 Phase 2 of Balancing Authority Reliability-based Controls BAL-005-1, BAL-006-3 & FAC-001-3 IN 1 ST

There were 46 sets of responses, including comments from approximately 131 different people from approximately 87 different companies representing 9 of the 10 Industry Segments as shown on the following pages.

All comments submitted can be reviewed in their original format on the project page.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Director of Standards, Howard Gugel (via email) or at (404) 446-9693.

Questions

1. **The SDT has modified the definition of Automatic Generation Control (AGC). Do you agree that this modified definition better represents the SDT intent to making resources more inclusive than just the traditional generation resources? If not, please explain in the comment area below.**
2. **The SDT has moved the BAL-005-0.2b Requirement R1 to FAC-001 since it provides for identifying interconnection Facilities and not for calculating Reporting ACE. Do you agree with moving this requirement into the FAC-001-3 standard? If not, please explain in the comment area below.**

3. **The SDT has moved the BAL-006-2 Requirement R3 into BAL-005-3 since this requirement directly impacts an entity's ability to calculate an accurate Reporting ACE. Do you agree with moving this requirement into the proposed BAL-005-1 standard? If not, please explain in the comment area below.**
4. **Please provide any issues you have on this draft of the BAL-005-1 standard and a proposed solution.**
5. **Please provide any issues you have on the proposed change to the BAL-006-3 standard and a proposed solution.**
6. **Please provide any issues you have on the proposed change to the FAC-001-3 standard and a proposed solution.**

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

1. The SDT has modified the definition of Automatic Generation Control (AGC). Do you agree that this modified definition better represents the SDT intent to making resources more inclusive than just the traditional generation resources? If not, please explain in the comment area below.

John Fontenot - Bryan Texas Utilities - 1 -	
Selected Answer:	Yes
Andrew Pusztai - American Transmission Company, LLC - 1 -	
Selected Answer:	Yes
Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO	
Selected Answer:	Yes
Richard Vine - California ISO - 2 -	
Answer Comment:	The California ISO supports the comments of the ISO/RTO Council Standards Review Committee for all questions in this Survey.
Response:	

Jeremy Voll - Basin Electric Power Cooperative - 3 -

Selected Answer: Yes

Leonard Kula - Independent Electricity System Operator - 2 -

Selected Answer: Yes

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Group Name: MRO-NERC Standards Review Forum (NSRF)

Group Member Name	Entity	Region	Segments
Joe Depoorter	Madison Gas & Electric	MRO	3,4,5,6
Amy Casucelli	Xcel Energy	MRO	1,3,5,6
Chuck Lawrence	American Transmission Company	MRO	1
Chuck Wicklund	Otter Tail Power Company	MRO	1,3,5
Theresa Allard	Minnkota Power Cooperative, Inc	MRO	1,3,5,6
Dave Rudolph	Basin Electric Power Cooperative	MRO	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5,6
Jodi Jenson	Western Area Power Administration	MRO	1,6
Larry Heckert	Alliant Energy	MRO	4
Mahmood Safi	Omaha Public Utility District	MRO	1,3,5,6
Shannon Weaver	Midwest ISO Inc.	MRO	2

Mike Brytowski	Great River Energy	MRO	1,3,5,6
Brad Perrett	Minnesota Power	MRO	1,5
Scott Nickels	Rochester Public Utilities	MRO	4
Terry Harbour	MidAmerican Energy Company	MRO	1,3,5,6
Tom Breene	Wisconsin Public Service Corporation	MRO	3,4,5,6
Tony Eddleman	Nebraska Public Power District	MRO	1,3,5

Selected Answer: Yes

Answer Comment: **We agree it makes AGC more inclusive and understand there was a FERC directive to make this change, but the directive does not add to reliability.**

Thank you for your affirmative response and clarifying comment. The SDT has further modified the definition of AGC.

Response:

Terry BIlke - Midcontinent ISO, Inc. - 2 -

Selected Answer: Yes

Likes: 0

Dislikes: 1 DTE Energy - Detroit Edison Company, 5, DePriest Jeffrey

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Selected Answer: Yes

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert Schaffeld	Southern Company Services, Inc	SERC	1
John Ciza	Southern Company Generation and Energy Marketing	SERC	6
R Scott Moore	Alabama Power Company	SERC	3
William Shultz	Southern Company Generation	SERC	5

Selected Answer: Yes

Eleanor Ewry - Puget Sound Energy, Inc. - 1,3,5 - WECC

Selected Answer: Yes

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable

Group Name: ACES Standards Collaborators

Group Member Name	Entity	Region	Segments
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Bill Hutchison	Southern Illinois Power Cooperative	SERC	1
Michael Brytowski	Great River Energy	MRO	1,3,5,6
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
John Shaver	Arizona Electric Power Cooperative, Inc.	WECC	4,5
John Shaver	Southwest Transmission Cooperative, Inc.	WECC	1
Ryan Strom	Buckeye Power, Inc.	RFC	4
Scott Brame	North Carolina Electric Membership Corporation	SERC	3,4,5
Bill Watson	Old Dominion Electric Cooperative	SERC	3,4

Selected Answer: Yes

Answer Comment: We agree that the modified definition is a step in the right direction. However, the definition references Demand Response in capital letters. While that concept is recognized by industry, it officially is not a NERC Glossary Term. We recommend that SDT rephrase the last sentence of this definition to read “Resources utilized under AGC may include, but not be limited to, conventional generation, variable energy resources, energy storage devices, and demand response resources.”

Thank you for your comments. The SDT has made changes to the definition of AGC to help resolve this issue.

Response:

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer: No

Answer Comment:

Texas RE does agree that the revised definition is more inclusive. There is a concern, however, about disregarding asynchronous Tie MWs in the calculation for Reporting ACE. If a Balancing Authority (BA) has 1000 MWs of generation and 500 MWS of load with the remaining generation being transferred asynchronously, how will the ACE equation , and subsequently AGC, work properly?

The Reporting ACE equation accounts for all generation and load. Any asynchronous Tie MWs to another Interconnection is accounted as either load or generation including such transfers.

With the revised definition of Reporting ACE, it appears the Standard Drafting Team (SDT) is disregarding single BA Interconnections, such as ERCOT and Quebec. Texas RE is concerned about the statement “All NERC Interconnections with multiple Balancing Authority Areas operate using the principles of Tie-bias (TLB) Control and requirement the use of

	an ACE equation similar to the Reporting ACE defined above." This statement implies that single BA Interconnections, such as ERCOT and Quebec do not operate using the principles of TLB and the use of ACE. If not, how does BAL-001 apply? Is indicating an "alternative" method for a Reporting ACE equation use advocating regional differences? The SDT believes the Reporting ACE still is applicable to a single BA interconnection using the principles of Tie-bias control. However, the SDT has made the following modification: All NERC Interconnections operate using the principles of Tie-line Bias (TLB) Control and require the use of an ACE equation similar to the Reporting ACE defined above. Texas RE inquires as to whether it is the SDT's intent that AGC (as currently defined in the proposed definition) will be only frequency-based for single-balancing authority areas. The definition does not change how one uses AGC nor does it change the applicable NERC Reliability Standards. In addition the SDT has modified the definition to add clarity. Please refer to our responses to Question #4 for additional information.
Response:	

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

David Jendras - Ameren - Ameren Services - 3 -

Selected Answer: Yes

Carol Chinn - Florida Municipal Power Agency - 4 -

Group Name: FMPA

Group Member Name	Entity	Region	Segments
Tim Beyrle	City of New Smyrna Beach	FRCC	4
Jim Howard	Lakeland Electric	FRCC	3
Greg Woessner	Kissimmee Utility Authority	FRCC	3
Lynne Mila	City of Clewiston	FRCC	3
Javier Cisneros	Fort Pierce Utility Authority	FRCC	4
Randy Hahn	Ocala Utility Services	FRCC	3
Don Cuevas	Beaches Energy Services	FRCC	1
Stan Rzad	Keys Energy Services	FRCC	4
Matt Culverhouse	City of Bartow	FRCC	3
Tom Reedy	Florida Municipal Power Pool	FRCC	6
Steven Lancaster	Beaches Energy Services	FRCC	3
Mike Blough	Kissimmee Utility Authority	FRCC	5
Mark Brown	City of Winter Park	FRCC	3

Mace Hunter	Lakeland Electric	FRCC	3

Selected Answer: No

Answer Comment: FMPA supports using the term resources to make the definition more inclusive, but the capitalized term Demand Response is not in the NERC glossary of terms.

The SDT has made changes to the definition of AGC to help resolve this issue.

Response:

Mark Holman - PJM Interconnection, L.L.C. - 2 -

Selected Answer: Yes

Answer Comment: PJM finds that the modified definition of AGC is inclusive of more resource types than only traditional generation resources. However, AGC equipment does not directly adjust the output of resources, but instead generates and sends control signals to the resources to change output. PJM suggests the following change to the definition for clarity:

Automatic Generation Control (AGC): Centrally located equipment that generates and sends control signals to automatically adjusts resources in a Balancing Authority Area to help maintain the Reporting ACE in that

	of a Balancing Authority Area within the bounds required by applicable NERC Reliability Standards. Resources utilized under AGC may include, but are not limited to, conventional generation, variable energy resources, storage devices and loads acting as resources (such as Demand Response). The SDT has made changes to the definition of AGC to help resolve this issue.
Response:	

Chantal Mazza - Hydro-Qu?bec TransEnergie - 2 - NPCC

Selected Answer:	Yes
Answer Comment:	AGC is no longer used in BAL-005-1, therefore HQ questions whether Project 2010-14.2.1 is the best opportunity to revise this definition. The SDT has made changes to the definition of AGC to help resolve this issue. However, since AGC adjustment impacts Reporting ACE, and Reporting ACE is critical for BAL-005, the SDT felt it was appropriate to adjust the definition under this process.

Response:

Theresa Rakowsky - Puget Sound Energy, Inc. - 1 -

Selected Answer: Yes

Answer Comment: The modification is on the correct track to expand the definition.

Response:

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Group Name: Duke Energy

Group Member Name	Entity	Region	Segments
Doug Hils	Duke Energy	RFC	1
Lee Schuster	Duke Energy	FRCC	3
Dale Goodwine	Duke Energy	SERC	5
Greg Cecil	Duke Energy	RFC	6

Selected Answer: Yes

Answer Comment: **Duke Energy recommends that the drafting team clarify or state that just because a term appears in a definition does not make the**

definition applicable to said term. For example, the term ***"Demand Response"*** **appears in the proposed definition of Automatic Generation Control (AGC), however, AGC does not adjust Demand Response. Clarification is needed from the drafting team stating that just because this term appears in the definition, this doesn't mean every type of Generating Resource, Load Resource, or Load reacting as a resource is capable of providing response to an AGC signal. Just because a term is listed in the definition, doesn't mean it should qualify as an example. We suggest the drafting team revise the language to include** ***"such as qualified demand resources"*** **rather than** ***"Demand Response"*** **which can mean a lot of different things.**

The SDT has made changes to the definition of AGC to help resolve this issue.

Response:

Andrea Basinski - Puget Sound Energy, Inc. - 3 -

Selected Answer: No

Brent Ingebrigtson - LG&E and KU Energy, LLC - 1,3,5,6 - SERC

Group Name: LG&E and KU Energy, LLC

Group Member Name	Entity	Region	Segments
Brent Ingebrigtson	LG&E adn KU energy, LLC	SERC	1,3,5,6
justin Bencomo	LG&E and KU Energy, LLC	SERC	1,3,5,6
Chjarlie Freibert	LG&E and KU Energy, LLC	SERC	3
Linn Oelker	LG&E and KU Energy, LLC	SERC	6
Dan Wilson	LG&E and KU Energy, LLC	SERC	5

Selected Answer: No

Answer Comment:

These comments are submitted on behalf LG&E and KU Energy, LLC (LG&E/KU). LG&E/KU is registered in the SERC Region for one or more of the following NERC functions: BA, DP, GO, GOP, IA, LSE, PA, RP, TO, TOP, TP, and TSP

Comments:

Making a definition "more inclusive" does not make it clearer or better. In fact, an argument can be made that an "inclusive" definition can become problematic. The proposed definition includes uneccessary, prescriptive language on what types of resources may be used for AGC. We are concerned that the list will raise expectations that VERs, storage devices and Demand Response resources should be included in an entity's AGC function. Many Demand Response programs (such as residential load interruption) are not compatible with AGC operations and should not be considered as such.

The last sentence of the proposed definition is not necessary, reduces the clarity of the definition and should be deleted.

Automatic Generation Control (AGC): Centrally located equipment that generates and sends control signals to automatically adjust resources in a Balancing Authority Area to help maintain the Reporting ACE in that of a Balancing Authority Area within the bounds required by applicable NERC Reliability Standards.

The SDT has made changes to the definition of AGC to help resolve this issue.

Response:

Douglas Webb - Douglas Webb On Behalf of: Chris Bridges, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1
Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1
James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1
Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1

Selected Answer: Yes

Matthew Beilfuss - WEC Energy Group, Inc. - 3,4,5,6 - MRO,RFC

Selected Answer: Yes

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Group Name: NPCC--Project 2010-14.2.1 Phase 2 of Bal Auth Rel-based Controls - BAL-005-1, BAL-006-3, FAC-001-3

Group Member Name	Entity	Region	Segments
Alan Adamson	New York State Reliability Council, LLC	NPCC	10
David Burke	Orange and Rockland Utilities Inc.	NPCC	3
Greg Campoli	New York Independent System Operator	NPCC	2
Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
Mark Kenny	Northeast Utilities	NPCC	1
Helen Lainis	Independent Electricity System Operator	NPCC	2
Rob Vance	New Brunswick Power Corporation	NPCC	9
Paul Malozewski	Hydro One Networks Inc.	NPCC	1
Bruce Metruck	New York Power Authority	NPCC	6
Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
Brian Robinson	Utility Services	NPCC	8
Wayne Sipperly	New York Power Authority	NPCC	5
Edward Bedder	Orange and Rockland Utilities Inc.	NPCC	1
Michael Jones	National Grid	NPCC	1
Brian Shanahan	National Grid	NPCC	1
Glen Smith	Entergy Services, Inc.	NPCC	5

RuiDa Shu	Northeast Power Coordinating Council	NPCC	10
Connie Lowe	Dominion Resources Services, Inc.	NPCC	5
Guy Zito	Northeast Power Coordinating Council	NPCC	10
Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
Robert Pellegrini	The United Illuminating Company	NPCC	1
Kathleen Goodman	ISO - New England	NPCC	2

Selected Answer: No

Answer Comment: The use of centrally located equipment, that automatically adjusts, maintain Reporting ACE, resources utilized under AGC needs to be considered.

There is no justification to link the definition of Automatic Generation Control (AGC) to a given location.

AGC is not hardware (equipment); AGC is software.

AGC does not “adjust resources” (that is usually accomplished at the resource itself). AGC “is used to adjust resources”.

AGC is not designed for reporting purposes. AGC is design to assist in the control of a BA’s balance of its resources to its NERC mandated balancing obligations.

Propose that the definition be revised to:

Automatic Generation Control (AGC): Software designed and used to adjust a Balancing Authority's resources to meet the BA's balancing requirements as required by applicable NERC Reliability Standards.

The SDT has made changes to the definition of AGC to help resolve this issue.

BAL-005 being a NERC standard and not one of the many regionally-approved standards is applicable to all Bas unless the BA is in a region in which the standard is superseded by a FERC-approved regional standard. Automatic Time Error Correction is not a part of the FERC-approved standards for all Bas. For clarity the regionally-approved definition and references to **Automatic Time Error Correction (I ATEC)** be deleted and left to an approved regional standard.

Under the FERC Order approving BAL-001-2 (Real Power Balancing Control Performance) NERC was directed to include ATEC in the ACE equation. Since Reporting ACE includes the definition for the Western Interconnection, ATEC must be defined and included in the definitions. The Reporting ACE definition was broken into sub-definitions to easily manage the specific Reporting ACE equation for each Interconnection, such as the ATEC term for the Western Interconnection.

Response:

Mike ONeil - NextEra Energy - Florida Power and Light Co. - 1 -

Selected Answer: Yes

Payam Farahbakhsh - Hydro One Networks, Inc. - 1 -

Selected Answer: No

Albert DiCaprio - PJM Interconnection, L.L.C. - 2 - RFC

Group Name: ISO Standards Review Committee

Group Member Name	Entity	Region	Segments
Charles Yeung	SPP	SPP	2
Ben Li	IESO	NPCC	2
Mark Holman	PJM	RFC	2
Kathleen Goodman	ISONE	NPCC	2
Greg Campoli	NYISO	NPCC	2
Ali Miremadi	CAISO	WECC	2
Terry Bilke	MISO	RFC	2
Christina Bigelow	ERCOT	TRE	2

Selected Answer: No

Answer Comment: The SRC does not agree with the proposed definition of AGC.

The SRC recommends the following definition for AGC:

Automatic Generation Control (AGC): *A process designed and used to adjust a Balancing Authority's resources to meet the BA's balancing requirements as required by applicable NERC Reliability Standards.*

The SDT has made changes to the definition of AGC to help resolve this issue.

See attached for the full text of the comments to Questions 1-6

Response:

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer: Yes

Shawna Speer - Colorado Springs Utilities - 1 -

Group Name: Colorado Springs Utilities

Group Member Name	Entity	Region	Segments
Shawna Speer	Colorado Springs Utilities	WECC	1
Shannon Fair	Colorado Springs Utilities	WECC	6
Charles Morgan	Colorado Springs Utilities	WECC	3

Kaleb Brimhall	Colorado Springs Utilities	WECC	5

Selected Answer: Yes

Jason Smith - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool	SPP	2
Jason Smith	Southwest Power Pool	SPP	2
Ashley Stringer	Oklahoma Municipal Power Authority	SPP	4

Selected Answer: No

Answer Comment: The added sentence at the end of the definition adequately serves the purpose of clarifying that all “resources” are included rather than just traditional generators. The change to add the descriptor “Centrally located” when describing the “equipment” is also problematic. There does not appear to be a stated justification for making that change and it could introduce issues in interpretation surrounding redundant systems or sub-systems that could or should be included in the system that is used for AGC. If there is a reason for continuing to include the “centrally located” descriptor, we suggest that the SDT clarify the reason.

	The SDT has made changes to the definition of AGC to help resolve this issue.
Response:	
Erika Doot - U.S. Bureau of Reclamation - 5 -	
Selected Answer:	Yes

2. The SDT has moved the BAL-005-0.2b Requirement R1 to FAC-001 since it provides for identifying interconnection Facilities and not for calculating Reporting ACE. Do you agree with moving this requirement into the FAC-001-3 standard? If not, please explain in the comment area below.

General Response of the SDT to comments received:

Has there ever been a situation where Load was not within a BA metered boundary? The answer to this question is yes, but it is the wrong question. The correct question is, "Can the addition of a new load without notice to the BA affect the ability of a BA to perform its balancing function adequately and thus detrimentally affect reliability?"

Requirement R1 from the Version 0 BAL-005 standard was originally included to meet the general requirement for Tie Line Bias Control to be effective. In the NERC Glossary of Terms, Reporting ACE requires that, "All portions of the Interconnection are included in one area [BAA] or another so that the sum of all area generation, loads and losses is the same as total system generation, load and losses." In its Version 0 form, R1 was difficult or impossible to audit. The new version of the standard addresses this reliability concern through a modification to the definition of Reporting ACE requiring that Actual Net Interchange and Scheduled Net Interchange only include interchange with other BAAs. By modifying the definition of Reporting ACE it becomes impossible to exclude any generator, transmission, or load from all BAAs on an interconnection because exclusion from one BAA can only be accomplished by transferring that generator, transmission or load to an adjacent BAA. In addition, inadvertent accounting from the new BAL-005-1 R7 will reveal any problems between Scheduled Net Interchange as compared to Actual Net Interchange within a BAA.

In its evaluation considering the elimination of this requirement, the STD realized that there is no requirement that the BA be informed of the new facilities to be interconnected before the actual interconnection would take place. This puts the BA in the unreasonable position of having to adjust its operations for new unknown generation, transmission or load without advanced notice. The intent of the additions to R3 and R4 to FAC-001 is to insure that the BA receives advanced notice of the interconnection. This is a one-time requirement since the change in the definition of Reporting ACE addressed the intent of the original BAL-005-0 R1 and the ongoing reliability issue. The drafting team has modified the requirements in FAC-001-3 so that they only apply to new interconnecting facilities or facility modifications that would require material facility changes, and therefore material changes in the load to be balanced.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:	Yes

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer:	Yes

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO

Selected Answer:	Yes

Thomas Foltz - AEP - 5 -

Selected Answer:	No
Answer Comment:	We do not agree that FAC-001 is the correct standard to house these obligations. FAC-001 applies to the interconnection of new facilities, while the R5, R6 & R7 Requirements taken from BAL-005-0.2b apply to all Transmission, Generation & Load facilities.

Response to Comment:	The SDT proposed changes to FAC-001, as it does not solely apply to the interconnection of new facilities, but it also requires notification of "new or materially modified existing interconnections". Requirement R1 from the Version 0 BAL-005 standard was originally included to meet the general requirement for Tie Line Bias Control to be effective. In the NERC Glossary of Terms, Reporting ACE requires that, "All portions of the Interconnection are included in one area [BAA] or another so that the sum of all area generation, loads and losses is the same as total system generation, load and losses." In its Version 0 form, R1 was difficult or impossible to audit. The new version of the standard addresses this reliability concern through a modification to the definition of Reporting ACE requiring that Actual Net Interchange and Scheduled Net Interchange only include interchange with other BAAs. By modifying the definition of Reporting ACE it becomes impossible to exclude any generator, transmission, or load from all BAAs on an interconnection because exclusion from one BAA can only be accomplished by transferring that generator, transmission or load to an adjacent BAA. In addition, inadvertent accounting from the new BAL-005-1 R7 will reveal any problems between Scheduled Net Interchange as compared to Actual Net Interchange within a BAA. In its evaluation considering the elimination of this requirement, the STD realized that there is no requirement that the BA be informed of the new facilities to be interconnected before the actual interconnection would take place. This puts the BA in the unreasonable position of having to adjust its operations for new unknown generation, transmission or load without advanced notice. The intent of the additions to R3 and R4 to FAC-001 is to insure that the BA receives advanced notice of the interconnection. This is a one-time requirement since the change in the definition of Reporting ACE addressed the intent of the original BAL-005-0 R1 and the ongoing reliability

issue. The drafting team has modified the requirements in FAC-001-3 so that they only apply to new interconnecting facilities or facility modifications that would require material facility changes, and therefore material changes in the load to be balanced.

In the event that the drafting team *is* successful in moving these obligations to FAC-001, the new requirements will need to be clarified so that the requirements apply only to new interconnecting facilities (consistent with the spirit of the other FAC-001 requirements). In that case, separate requirements will still be required elsewhere to apply to existing Transmission, Generation & Load facilities. In addition, it would also be incumbent on the TO to ensure that the wording for these obligations are explicit within their interconnect agreements and the necessary interconnect guides that are specified in FAC-001.

The SDT agrees that the requirements should be re-worded and has made the necessary modifications.

AEP's decision to vote negative on this proposal is driven by these objections.

Answer Comment:

Response to Comment:

Response:

Tammy Porter - Tammy Porter On Behalf of: Rod Kinard, Oncor Electric Delivery, 1

Selected Answer: Yes

Louis Slade - Dominion - Dominion Resources, Inc. - 6 -

Group Name: Dominion

Group Member Name	Entity	Region	Segments
Randi Heise	NERC Compliance Policy	NPCC	5,6
Connie Lowe	NERC Compliance Policy	SERC	1,3,5,6
Louis Slade	NERC Compliance Policy	RFC	5,6
Chip Humphrey	Power Generation Compliance	SERC	5
Nancy Ashberry	Power Generation Compliance	RFC	5
Larry Nash	Electric Transmission Compliance	SERC	1,3
Candace L Marshall	Electric Transmission Compliance	SERC	1,3
Larry W Bateman	Transmission Compliance	SERC	1,3
Jeffrey N Bailey	Nuclear Compliance	SERC	5
Russell Deane	Nuclear Compliance	NPCC	5

Selected Answer: Yes

Jeremy Voll - Basin Electric Power Cooperative - 3 -

Selected Answer: No

Answer Comment:

It is not necessary to move this requirement. The SDT is taking a flawed requirement and moving it to another location. The requirement should be improved as follows.

R1. All generation, transmission, and load operating within an Interconnection must be included within the metered boundaries of a Balancing Authority Area.

The requirement above was a concept (Control Area Criteria) that was swept into the V0 standard. The only way to prove that everything is within the metered bounds of a BA is via Inadvertent Interchange accounting. R1 should be kept as-is, the sub-bullets removed and the measure for R1 should be:

Response to Comment:

Requirement R1 from the Version 0 BAL-005 standard was originally included to meet the general requirement for Tie Line Bias Control to be effective. In the NERC Glossary of Terms, Reporting ACE requires that, "All portions of the Interconnection are included in one area [BAA] or another so that the sum of all area generation, loads and losses is the same as total system generation, load and losses." In its Version 0 form, R1 was difficult or impossible to audit. The new version of the standard addresses this reliability concern through a modification to the definition of Reporting ACE requiring that Actual Net Interchange and Scheduled Net Interchange only include interchange with other BAAs. By modifying the definition of Reporting ACE it becomes impossible to exclude any generator, transmission, or load from all BAAs on an interconnection because exclusion from one BAA can only be accomplished by transferring that generator, transmission or load to an adjacent BAA. In addition, inadvertent accounting from the new BAL-005-1 R7 will reveal any problems between Scheduled Net Interchange as compared to Actual Net Interchange within a BAA.

In its evaluation considering the elimination of this requirement, the STD realized that there is no requirement that the BA be informed of the new facilities to be interconnected before the actual interconnection would take place. This puts the BA in the unreasonable position of having to adjust its operations for new unknown generation, transmission or load without advanced notice. The intent of the additions to R3 and R4 to FAC-001 is to insure that the BA receives advanced notice of the interconnection. This is a one-time requirement since the change in the definition of Reporting ACE addressed the intent of the original BAL-005-0 R1 and the ongoing reliability issue. The drafting team has modified the requirements in FAC-001-3 so that they only apply to new interconnecting facilities or facility modifications that would require material facility changes, and therefore material changes in the load to be balanced.

Answer Comment:

M1. The Balancing Authority was unable to agree with an Adjacent Balancing Authority when performing Inadvertent Interchange accounting and it was found that the Balancing Authority had an error in its model or tie lines that misstated its Net Actual Interchange value in its Inadvertent Interchange accounting.

Response:

Leonard Kula - Independent Electricity System Operator - 2 -

Selected Answer: Yes

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Group Name: MRO-NERC Standards Review Forum (NSRF)

Group Member Name	Entity	Region	Segments
Joe Depoorter	Madison Gas & Electric	MRO	3,4,5,6
Amy Casucelli	Xcel Energy	MRO	1,3,5,6
Chuck Lawrence	American Transmission Company	MRO	1
Chuck Wicklund	Otter Tail Power Company	MRO	1,3,5
Theresa Allard	Minnkota Power Cooperative, Inc	MRO	1,3,5,6
Dave Rudolph	Basin Electric Power Cooperative	MRO	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5,6
Jodi Jenson	Western Area Power Administration	MRO	1,6
Larry Heckert	Alliant Energy	MRO	4
Mahmood Safi	Omaha Public Utility District	MRO	1,3,5,6
Shannon Weaver	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Brad Perrett	Minnesota Power	MRO	1,5
Scott Nickels	Rochester Public Utilities	MRO	4
Terry Harbour	MidAmerican Energy Company	MRO	1,3,5,6

Tom Breene	Wisconsin Public Service Corporation	MRO	3,4,5,6
Tony Eddleman	Nebraska Public Power District	MRO	1,3,5

Selected Answer: No

Answer Comment: See attachment with strikethrough.

It is not necessary to move this requirement. The SDT is taking a flawed requirement and moving it to another location. The requirement should be improved as follows.

R1. All generation, transmission, and load operating within an Interconnection must be included within the metered boundaries of a Balancing Authority Area.

R1.1. Each Generator Operator with generation facilities operating in an Interconnection shall ensure that those generation facilities are included within the metered boundaries of a Balancing Authority Area.

R1.2. Each Transmission Operator with transmission facilities operating in an Interconnection shall ensure that those transmission facilities are included within the metered boundaries of a Balancing Authority Area.

R1.3. Each Load-Serving Entity with load operating in an Interconnection shall ensure that those loads are included within the metered boundaries of a Balancing Authority Area.

The requirement above was a concept (Control Area Criteria) that was swept into the V0 standard. The only way to prove that everything is

within the metered bounds of a BA is via Inadvertent Interchange accounting. R1 should be kept as-is, the sub-bullets removed and the measure for R1 should be:

Response to Comment:	Requirement R1 from the Version 0 BAL-005 standard was originally included to meet the general requirement for Tie Line Bias Control to be effective. In the NERC Glossary of Terms, Reporting ACE requires that, "All portions of the Interconnection are included in one area [BAA] or another so that the sum of all area generation, loads and losses is the same as total system generation, load and losses." In its Version 0 form, R1 was difficult or impossible to audit. The new version of the standard addresses this reliability concern through a modification to the definition of Reporting ACE requiring that Actual Net Interchange and Scheduled Net Interchange only include interchange with other BAAs. By modifying the definition of Reporting ACE it becomes impossible to exclude any generator, transmission, or load from all BAAs on an interconnection because exclusion from one BAA can only be accomplished by transferring that generator, transmission or load to an adjacent BAA. In addition, inadvertent accounting from the new BAL-005-1 R7 will reveal any problems between Scheduled Net Interchange as compared to Actual Net Interchange within a BAA. In its evaluation considering the elimination of this requirement, the STD realized that there is no requirement that the BA be informed of the new facilities to be interconnected before the actual interconnection would take place. This puts the BA in the unreasonable position of having to adjust its operations for new unknown generation, transmission or load without advanced notice. The intent of the additions to R3, and R4 to FAC-001 is to insure that the BA receives advanced notice of the interconnection. This is a one-time requirement since the change in the definition of Reporting ACE addressed the intent of the original BAL-005-0 R1 and the ongoing reliability

issue. The drafting team has modified the requirements in FAC-001-3 so that they only apply to new interconnecting facilities or facility modifications that would require material facility changes, and therefore material changes in the load to be balanced. The LSE has been removed from the standard based on the RBR initiative.

Answer Comment:

M1. The Balancing Authority was unable to agree with an Adjacent Balancing Authority when performing Inadvertent Interchange accounting and it was found that the Balancing Authority had an error in its model or tie lines that misstated its Net Actual Interchange value in its Inadvertent Interchange accounting.

Response:

Terry BIlke - Midcontinent ISO, Inc. - 2 -

Selected Answer: No

Answer Comment:

It is not necessary to move this requirement. The requirement can be improved by keeping it where it is and limiting it to:

R1. All generation, transmission, and load operating within an Interconnection must be included within the metered boundaries of a Balancing Authority Area.

The requirement is a concept from the NERC Operating Manual (Control Area Criteria) that was swept into the V0 standard. There is only one way to prove that everything is within the metered bounds of a BA, that is through

Inadvertent Interchange accounting. Thus the measure for this requirement should be:

Response to Comment:

Requirement R1 from the Version 0 BAL-005 standard was originally included to meet the general requirement for Tie Line Bias Control to be effective. In the NERC Glossary of Terms, Reporting ACE requires that, "All portions of the Interconnection are included in one area [BAA] or another so that the sum of all area generation, loads and losses is the same as total system generation, load and losses." In its Version 0 form, R1 was difficult or impossible to audit. The new version of the standard addresses this reliability concern through a modification to the definition of Reporting ACE requiring that Actual Net Interchange and Scheduled Net Interchange only include interchange with other BAAs. By modifying the definition of Reporting ACE it becomes impossible to exclude any generator, transmission, or load from all BAAs on an interconnection because exclusion from one BAA can only be accomplished by transferring that generator, transmission or load to an adjacent BAA. In addition, inadvertent accounting from the new BAL-005-1 R7 will reveal any problems between Scheduled Net Interchange as compared to Actual Net Interchange within a BAA.

In its evaluation considering the elimination of this requirement, the STD realized that there is no requirement that the BA be informed of the new facilities to be interconnected before the actual interconnection would take place. This puts the BA in the unreasonable position of having to adjust its operations for new unknown generation, transmission or load without advanced notice. The intent of the additions to R3 and R4 to FAC-001 is to insure that the BA receives advanced notice of the interconnection. This is a one-time requirement since the change in the definition of Reporting ACE addressed the intent of the original BAL-005-0 R1 and the ongoing reliability issue. The drafting team has modified the requirements in FAC-001-3 so that

	they only apply to new interconnecting facilities or facility modifications that would require material facility changes, and therefore material changes in the load to be balanced.
Answer Comment:	M1. The Balancing Authority was unable to agree with an Adjacent Balancing Authority when performing Inadvertent Interchange accounting and it was found that the Balancing Authority had an error in its model or tie lines that misstated its Net Actual Interchange value in its Inadvertent Interchange accounting.
Response:	

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Selected Answer:	No
Answer Comment:	BAL-005-0.2b R1 should remain where it is, but would be improved by the removal of the sub Requirements. The only means to prove that everything is within the metered boudaries of a Balancing Authority is through Inadvertent Interchange accounting. The revised R1 should read: R1. All generation, transmission, and load operating within an Interconnection must be included within the metered boundaries of a Balancing Authority Area.
Response to Comment:	Requirement R1 from the Version 0 BAL-005 standard was originally included to meet the general requirement for Tie Line Bias Control to be effective. In

	the NERC Glossary of Terms, Reporting ACE requires that, "All portions of the Interconnection are included in one area [BAA] or another so that the sum of all area generation, loads and losses is the same as total system generation, load and losses." In its Version 0 form, R1 was difficult or impossible to audit. The new version of the standard addresses this reliability concern through a modification to the definition of Reporting ACE requiring that Actual Net Interchange and Scheduled Net Interchange only include interchange with other BAAs. By modifying the definition of Reporting ACE it becomes impossible to exclude any generator, transmission, or load from all BAAs on an interconnection because exclusion from one BAA can only be accomplished by transferring that generator, transmission or load to an adjacent BAA. In addition, inadvertent accounting from the new BAL-005-1 R7 will reveal any problems between Scheduled Net Interchange as compared to Actual Net Interchange within a BAA. In its evaluation considering the elimination of this requirement, the STD realized that there is no requirement that the BA be informed of the new facilities to be interconnected before the actual interconnection would take place. This puts the BA in the unreasonable position of having to adjust its operations for new unknown generation, transmission or load without advanced notice. The intent of the additions to R3 and R4 to FAC-001 is to insure that the BA receives advanced notice of the interconnection. This is a one-time requirement since the change in the definition of Reporting ACE addressed the intent of the original BAL-005-0 R1 and the ongoing reliability issue. The drafting team has modified the requirements in FAC-001-3 so that they only apply to new interconnecting facilities or facility modifications that would require material facility changes, and therefore material changes in the load to be balanced. The measure M1 should read: M1. The Balancing Authority was unable to

Answer Comment: agree with an Adjacent Balancing Authority when performing Inadvertent Interchange accounting and it was found that the Balancing Authority had an error in its model or tie lines that misstate its Nets Actual Interchange value in its Inadvertent Interchange accounting.

Response:

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert Schaffeld	Southern Company Services, Inc	SERC	1
John Ciza	Southern Company Generation and Energy Marketing	SERC	6
R Scott Moore	Alabama Power Company	SERC	3
William Shultz	Southern Company Generation	SERC	5

Selected Answer: No

Answer Comment: While there is agreement with the removal of R1 from BAL-005-0.2b, the insertion of 4.1.3, and R5-R7 into FAC-001-2 is not required. Notification of an entities inclusion within a Balancing Authority's metered boundaries can be accomplished through the NERC Rules of Procedure, Section 500, FAC-001-2, proposed standard TOP-003-3 and existing standard IRO-010-2. For example, sufficient latitude exists within FAC-001-2 as approved, for the TO to provide notification to "those responsible for the reliability of the affected system(s) of new or materially modified existing interconnections." Through this requirement, the TO can provide a list of new or modified facilities (such as new or modified load, transmission and generator connections) to the TOP, BA and RC.

Response to Comment:

In FAC-001-2 R2, the words "upon request" are used in conjunction with the notification requirements. How does a BA know when to request such information? In FAC-001-2 R3, there is no specific mention of the BA. How does the TO know when the new load will affect the reliability functionality of the BA, or must the TO notify the BA for every request for interconnection? The new requirements were intended to remove the TO as the middleman for these requirements. TOP-003-3 includes the following words, "Each Balancing Authority shall retain evidence for three calendar years that it has distributed its data specification to entities that have data required by the Balancing Authority's analysis functions and Real-time monitoring in accordance with Requirement R4 and Measurement M4." How is the Balancing Authority to receive the knowledge that new load, generation or transmission is interconnecting so that it may distribute its data specification to entities that have data required by the Balancing Authority? This is the hole in the standards that modifications to FAC-001 R3 and R4 are intended to fill.

In its evaluation considering the elimination of this requirement, the STD realized that there is no requirement that the BA be informed of the new facilities to be interconnected before the actual interconnection would take place. This puts the BA in the unreasonable position of having to adjust its operations for new unknown generation, transmission or load without advanced notice. The intent of the additions to R3 and R4 to FAC-001 is to insure that the BA receives advanced notice of the interconnection. This is a one-time requirement since the change in the definition of Reporting ACE

	addressed the intent of the original BAL-005-0 R1 and the ongoing reliability issue. The drafting team has modified the requirements in FAC-001-3 so that they only apply to new interconnecting facilities or facility modifications that would require material facility changes, and therefore material changes in the load to be balanced.
Response:	
Eleanor Ewry - Puget Sound Energy, Inc. - 1,3,5 - WECC	
Selected Answer:	No
Answer Comment:	As worded, we do not believe these requirements are appropriate for FAC-001-3. Since FAC-001-3 applies to documented Facility interconnection requirements, it would be more appropriate to require that the documented interconnection requirements contain language stating that transmission, generation and end-user interconnected Facilities must be located within the Balancing Authority Area's metered boundaries. This could be accomplished by adding R3.3 stating "Procedures for ensuring that transmission Facilities, generation Facilities and end-user Facilities are within the Balancing Authority Area's metered boundaries." The requirement to verify that existing facilities are located with the metered boundaries of a Balancing Authority Area is most appropriately assigned to the TOP, and not to the TO, GO and the LSE.
Response to Comment:	Requirement R1 from the Version 0 BAL-005 standard was originally included to meet the general requirement for Tie Line Bias Control to be effective. In

the NERC Glossary of Terms, Reporting ACE requires that, "All portions of the Interconnection are included in one area [BAA] or another so that the sum of all area generation, loads and losses is the same as total system generation, load and losses." In its Version 0 form, R1 was difficult or impossible to audit. The new version of the standard addresses this reliability concern through a modification to the definition of Reporting ACE requiring that Actual Net Interchange and Scheduled Net Interchange only include interchange with other BAAs. By modifying the definition of Reporting ACE it becomes impossible to exclude any generator, transmission, or load from all BAAs on an interconnection because exclusion from one BAA can only be accomplished by transferring that generator, transmission or load to an adjacent BAA. In addition, inadvertent accounting from the new BAL-005-1 R7 will reveal any problems between Scheduled Net Interchange as compared to Actual Net Interchange within a BAA.

In its evaluation considering the elimination of this requirement, the STD realized that there is no requirement that the BA be informed of the new facilities to be interconnected before the actual interconnection would take place. This puts the BA in the unreasonable position of having to adjust its operations for new unknown generation, transmission or load without advanced notice. The intent of the additions to R3 and R4 to FAC-001 is to insure that the BA receives advanced notice of the interconnection. This is a one-time requirement since the change in the definition of Reporting ACE addressed the intent of the original BAL-005-0 R1 and the ongoing reliability issue. The drafting team has modified the requirements in FAC-001-3 so that they only apply to new interconnecting facilities or facility modifications that would require material facility changes, and therefore material changes in the load to be balanced.

Response:

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable

Group Name: ACES Standards Collaborators

Group Member Name	Entity	Region	Segments
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Bill Hutchison	Southern Illinois Power Cooperative	SERC	1
Michael Brytowski	Great River Energy	MRO	1,3,5,6
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
John Shaver	Arizona Electric Power Cooperative, Inc.	WECC	4,5
John Shaver	Southwest Transmission Cooperative, Inc.	WECC	1
Ryan Strom	Buckeye Power, Inc.	RFC	4
Scott Brame	North Carolina Electric Membership Corporation	SERC	3,4,5
Bill Watson	Old Dominion Electric Cooperative	SERC	3,4

Selected Answer: No

Answer Comment: 1. We concur that the intent of BAL-005-0.2b Requirement R1 provides for identification of Interconnection Facilities and not for the calculation of

	Reporting ACE. We question if the SDT followed the recommendations of the Project 2010-14.2 BAL Standards PRT to "explore if the role of the TOP would appropriately cover the loads interconnected to that TOP such that the LSE requirement may not be necessary." We ask the SDT to provide rationale for the proposed FAC-001-3 standard to explain their conclusion on why they continue to list the LSE as an applicable entity. We remind the SDT that the retirement of the LSE is pending FERC approval through the Risk-Based Registration (RBR) initiative. We do not understand why the SDT feels like the LSE has a reliability role, when the ERO continues to argue that the LSE is primarily focused on commercial activities and other entities, such as the TOP, would continue to meet reliability needs without the LSE. We strongly recommend that the drafting team remove the LSE from the applicability section. 2. As listed within this project's SAR, the Project 2010-14.2 BAL Standards PRT "believes that the requirements to identify the applicable BA should perhaps be in the interconnection agreements (via FERC's OATT or NAESB, for example)," we believe these requirements already do. Many other reliability requirements in the TOP and IRO standards support the identification of Interconnection Facilities through data modeling and specifications. For example, TOP-003-3 R4 identifies that "each Balancing Authority shall distribute its data specification to entities that have data required by the Balancing Authority's analysis functions and Real-time monitoring." If a BA needs information regarding a particular load, generation resource, or transmission line operating within its BA Area, based on this requirement, would they not "identify" the correct entity to send their specification? Furthermore, NERC has spent significant time and resources on the development of the BES definition and the removal of the LSE from its functional model. These efforts were accomplished to focus on entities and facilities that posed a significant risk to BES reliability. The SDT has already identified that the intent of these requirements is not for the

	calculation of Reporting ACE and only the identification of entities. Moreover, if a generation resource, transmission line, or load is not properly accounted for in the calculation of Reporting ACE, Inadvertent Interchange will result and the BA would investigate to correct the discrepancy, as a best practice, accordingly. We recommend the SDT remove these requirements from the proposed draft standards.
Response to Comment:	In its evaluation considering the elimination of this requirement, the STD realized that there is no requirement that the BA be informed of the new facilities to be interconnected before the actual interconnection would take place. This puts the BA in the unreasonable position of having to adjust its operations for new unknown generation, transmission or load without advanced notice. The intent of the additions to R3 and R4 to FAC-001 is to insure that the BA receives advanced notice of the interconnection. This is a one-time requirement since the change in the definition of Reporting ACE addressed the intent of the original BAL-005-0 R1 and the ongoing reliability issue. The drafting team has modified the requirements in FAC-001-3 so that they only apply to new interconnecting facilities or facility modifications that would require material facility changes, and therefore material changes in the load to be balanced. In FAC-001-2 R2, the words “upon request” are used in conjunction with the notification requirements. How does a BA know when to request such information? In FAC-001-2 R3, there is no specific mention of the BA. How does the TO know when the new load will affect the reliability functionality of the BA, or must the TO notify the BA for every request for interconnection? The new requirements were intended to remove the TO as the middleman for these requirements. TOP-003-3 includes the following

	words, “Each Balancing Authority shall retain evidence for three calendar years that it has distributed its data specification to entities that have data required by the Balancing Authority’s analysis functions and Real-time monitoring in accordance with Requirement R4 and Measurement M4.” How is the Balancing Authority to receive the knowledge that new load, generation or transmission is interconnecting so that it may distribute its data specification to entities that have data required by the Balancing Authority? This is the hole in the standards that modifications to FAC-001 R3 and R4 are intended to fill.
Response:	
Jonathan Appelbaum - United Illuminating Co. - 1 -	
Selected Answer:	No
Answer Comment:	First, a quick review of the Standards shows there is no other specific requirement to ensure a facility is in a metered boundry or telemtery is provided to a RC, BA, or TOP. This requirement is to ensure that a load or generator is metered and communicated to BA for BA function. It is just as important that line metering is reported to TOP and RC, yet there is no FAC requirement to install metering and telemetry. For TOP and RC, there is TOP-03 and IRO-010 with a data specification and process to deliver data.
Response to Comment:	Requirement R1 from the Version 0 BAL-005 standard was originally included to meet the general requirement for Tie Line Bias Control to be effective. In the NERC Glossary of Terms, Reporting ACE requires that, “All portions of the

Interconnection are included in one area [BAA] or another so that the sum of all area generation, loads and losses is the same as total system generation, load and losses." In its Version 0 form, R1 was difficult or impossible to audit. The new version of the standard addresses this reliability concern through a modification to the definition of Reporting ACE requiring that Actual Net Interchange and Scheduled Net Interchange only include interchange with other BAAs. By modifying the definition of Reporting ACE it becomes impossible to exclude any generator, transmission, or load from all BAAs on an interconnection because exclusion from one BAA can only be accomplished by transferring that generator, transmission or load to an adjacent BAA. In addition, inadvertent accounting from the new BAL-005-1 R7 will reveal any problems between Scheduled Net Interchange as compared to Actual Net Interchange within a BAA.

Answer Comment:

Second, FAC-001 is about developing a single document for one-time use by an interconnecting entity to know what is required to complete an interconnection. The proposed change creates an ongoing requirement to conform that the interconnection is in the metered boundaries of the BA. The proposed requirement is not consistent with FAC-001. A consistent approach to FAC-001 is to require that the requirements address the metering required to facilitate the BA function, but this is already implied in the current FAC-001-2 standard.

Response to Comment:

The SDT has modified FAC-001 to address your issue.

Answer Comment:

Balancing is becoming a complicated function as compared to the Version 0 days. The BA should have its own data specification standard similar to TOP-003 or IRO-010. In the alternative these requirements should be retired, with the comment that the requirement is implied already in FAc-001-2 and the Technical and Guideline section of FAC-001-2 will be updated to include a specific explanation of including interconnection in BA metered boundary.

The goal of the NERC Reliability Standards are to be clear not to imply requirements.

Response to Comment:

Response:

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer: No

Answer Comment:

Texas RE noticed that the Load-Serving Entity (LSE) function was added to the FAC-001-3 applicability but is not mentioned in the Evidence Retention section.
Thank you for your comment. The SDT has made the necessary modifications. The LSE has been removed from the standard based on the RBR initiative.

Texas RE noticed the term, “Transmission Facilities” is capitalized in R5 but not in R1.2. The term “Transmission Facilities” is not a defined term in the NERC glossary so it could cause confusion if capitalized.

Thank you for your comments, the SDT has incorporated your suggestions.

Response:

Bob Thomas - Illinois Municipal Electric Agency - 4 -

Selected Answer: No

Answer Comment: Given the strongly supported rationale for deactivating the LSE registration function under the Risk-Based Registration initiative, Requirement 1.3 of BAL-005-0.2b should not be moved to FAC-001-3 as Requirement 7. The necessity of retaining this language for reliability purposes should be reconsidered. [Has there ever been a situation where Load was not within a BA metered boundary?] If this language is needed for reliability, an alternate functional entity should be identified.

Response to Comment: Has there ever been a situation where Load was not within a BA metered boundary? The answer to this question is yes, but it is the wrong question. The correct question is, "Can the addition of a new load without notice to the BA affect the ability of a BA to perform its balancing function adequately and thus detrimentally affect reliability?"

Requirement R1 from the Version 0 BAL-005 standard was originally included to meet the general requirement for Tie Line Bias Control to be effective. In the NERC Glossary of Terms, Reporting ACE requires that, "All portions of the Interconnection are included in one area [BAA] or another so that the sum of all area generation, loads and losses is the same as total system generation, load and losses." In its Version 0 form, R1 was difficult or impossible to audit. The new version of the standard addresses this reliability concern through a modification to the definition of Reporting ACE requiring that Actual Net

Interchange and Scheduled Net Interchange only include interchange with other BAAs. By modifying the definition of Reporting ACE it becomes impossible to exclude any generator, transmission, or load from all BAAs on an interconnection because exclusion from one BAA can only be accomplished by transferring that generator, transmission or load to an adjacent BAA. In addition, inadvertent accounting from the new BAL-005-1 R7 will reveal any problems between Scheduled Net Interchange as compared to Actual Net Interchange within a BAA.

In its evaluation considering the elimination of this requirement, the STD realized that there is no requirement that the BA be informed of the new facilities to be interconnected before the actual interconnection would take place. This puts the BA in the unreasonable position of having to adjust its operations for new unknown generation, transmission or load without advanced notice. The intent of the additions to R3 and R4 to FAC-001 is to insure that the BA receives advanced notice of the interconnection. This is a one-time requirement since the change in the definition of Reporting ACE addressed the intent of the original BAL-005-0 R1 and the ongoing reliability issue. The drafting team has modified the requirements in FAC-001-3 so that they only apply to new interconnecting facilities or facility modifications that would require material facility changes, and therefore material changes in the load to be balanced. The LSE has been removed from the standard based on the RBR initiative.

Response:

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

David Jendras - Ameren - Ameren Services - 3 -

Selected Answer: No

Answer Comment: **Ameren supports MISO's comments for this question**

Response:

Carol Chinn - Florida Municipal Power Agency - 4 -

Group Name: FMPA

Group Member Name	Entity	Region	Segments
Tim Beyrle	City of New Smyrna Beach	FRCC	4
Jim Howard	Lakeland Electric	FRCC	3
Greg Woessner	Kissimmee Utility Authority	FRCC	3
Lynne Mila	City of Clewiston	FRCC	3
Javier Cisneros	Fort Pierce Utility Authority	FRCC	4
Randy Hahn	Ocala Utility Services	FRCC	3
Don Cuevas	Beaches Energy Services	FRCC	1
Stan Rzad	Keys Energy Services	FRCC	4
Matt Culverhouse	City of Bartow	FRCC	3
Tom Reedy	Florida Municipal Power Pool	FRCC	6

Steven Lancaster	Beaches Energy Services	FRCC	3
Mike Blough	Kissimmee Utility Authority	FRCC	5
Mark Brown	City of Winter Park	FRCC	3
Mace Hunter	Lakeland Electric	FRCC	3

Selected Answer: No

Answer Comment: FMPA believes these requirements should be retired on the basis that they are covered by the data specification requirements of Board approved TOP-003-3. While it may be appropriate to include the concept of meters and BA metered boundaries in Facility interconnection requirements, as currently worded the proposed requirements do not fit with the purpose or applicability of FAC-001.

Response to Comment: In FAC-001-2 R2, the words "upon request" are used in conjunction with the notification requirements. How does a BA know when to request such information? In FAC-001-2 R3, there is no specific mention of the BA. How does the TO know when the new load will affect the reliability functionality of the BA, or must the TO notify the BA for every request for interconnection? The new requirements were intended to remove the TO as the middleman for these requirements. TOP-003-3 includes the following words, "Each Balancing Authority shall retain evidence for three calendar years that it has distributed its data specification to entities that have data required by the Balancing Authority's analysis functions and Real-time monitoring in accordance with Requirement R4 and Measurement M4." How is the Balancing Authority to receive the knowledge that new load, generation or transmission is interconnecting so that it may distribute its data specification to entities that have data required by the Balancing Authority? This is the hole in the standards that modifications to FAC-001 R3 and R4 are intended to fill.

Response:

Mark Holman - PJM Interconnection, L.L.C. - 2 -

Selected Answer: No

Answer Comment:

With moving BAL-005-0.2b R1 to FAC-001 R5 and R6, the requirement has shifted from being a Generator and Transmission Operator function to a Generator and Transmission Owner function. PJM questions and considers consequences with this change. PJM seeks clarity on the following topics:

Generation Owners, Transmission Owners, and Load-Serving Entities have no requirement to supply the Balancing Authority with data that affects the ACE calculation. PJM proposes the following changes to FAC-001 R5, R6, and R7:

R5. Each Transmission Owner with transmission Facilities operating in an Interconnection shall confirm that each transmission Facility is within a Balancing Authority Area's metered boundaries. The Transmission Owner shall coordinate any changes caused to the ACE due to each transmission Facility with the impacted Balancing Authorities.

R6. Each Generator Owner with generation Facilities operating in an Interconnection shall confirm that each generation Facility is within a Balancing Authority Area's metered boundaries. The Generation Owner shall coordinate any changes caused to the ACE due to each generation Facility with impacted Balancing Authorities.

R7. Each Load-Serving Entity with Load operating in an Interconnection shall confirm that each Load is within a Balancing Authority Area's metered boundaries. The Load-Serving Entity shall coordinate changes caused to the ACE due to each Load with impacted Balancing Authorities.

The LSE has been removed from the standard based on the RBR initiative.

Since Reporting ACE is made up of many components, including Net Actual Interchange (NIA), Balancing Authorities will be dependent on the Generator Owners, Transmission Owners, and Load-Serving Entities for this data. When ACE is impacted by the identified Interconnection Facilities, how should Reporting ACE be addressed by the Balancing Authority or Reliability Coordinator? If a Generator, Transmission Owner, or load-Serving Entity fail to confirm that each of their Facilities are within the Balancing Authority Area's metered boundaries, is the affected Balancing Authority responsible for calculating an accurate Reporting ACE?

It is the responsibility of all BAAs to calculate Reporting ACE correctly at all times. Absent of metering out generation, transmission or load which cannot be done without having an adjacent BAA involved, the metering of those entities is not used in the calculation of Reporting ACE. Though Reporting ACE may be accurate, the BA may not be capable of accurately estimating their resource requirements to balance Demand and generation. The LSE has been removed from the standard based on the RBR initiative.

What effects will this have on R5? Will the Balancing Authority be aware data from the Generator Owner or Transmission Owner are missing or invalid if the Generator Owner or Transmission Owner have not confirmed it?

This is the hole in the standards that modifications to FAC-001 R3 and R4 are intended to fill.

Response:

Chantal Mazza - Hydro-Qu?bec TransEnergie - 2 - NPCC

Selected Answer: No

Answer Comment:

FAC-001 is about Facility Interconnection Requirements. In the application guidelines of FAC-001-2, it is mentioned that these requirements include metering and telecommunications and as such could be interpreted to already include a requirement of metering to the BA. Meeting of facility interconnection requirements however is the purpose of FAC-002-1.

Therefore 2 options are available:

1. Modify the purpose of FAC-001 to include the GO, TO and LSE,DP or end-user meeting with facility interconnection requirements (whereas presently the purpose is only to make these requirements available) and add in section B, requirements for the GO, TO and LSE,DP or end-user to comply with all requirements set out in R1 thru R4 (not only with the requirement of being within a BA’s metered boundaries as is the case with Project 2010-14.2.1 proposal). Revise purpose of FAC-002-1 so that it addresses coordination studies rather than meeting facility connection and performance requirements.
2. Change the title of FAC-002 which presently is a bit at odds with its

	purpose and add requirements for the GO, TO and LSE,DP or end-user to comply with all requirements set out in FAC-001. The SDT has modified FAC-001 to address your concerns. The LSE has been removed from the standard based on the RBR initiative.
Response:	

Theresa Rakowsky - Puget Sound Energy, Inc. - 1 -	
Selected Answer:	No
Answer Comment:	As worded, we do not believe these requirements are appropriate for FAC-001-3. Since FAC-001-3 applies to documented Facility interconnection requirements, it would be more appropriate to require that the documented interconnection requirements contain language stating that transmission, generation and end-user interconnected Facilities must be located within the Balancing Authority Area's metered boundaries. This could be accomplished by adding R3.3 stating "Procedures for ensuring that transmission Facilities, generation Facilities and end-user Facilities are within the Balancing Authority Area's metered boundaries." The requirement to verify that existing facilities are located with the metered boundaries of a Balancing Authority Area is most appropriately assigned to the TOP, and not to the TO, GO and the LSE.
Response to Comments:	Requirement R1 from the Version 0 BAL-005 standard was originally included to meet the general requirement for Tie Line Bias Control to be effective. In

the NERC Glossary of Terms, Reporting ACE requires that, "All portions of the Interconnection are included in one area [BAA] or another so that the sum of all area generation, loads and losses is the same as total system generation, load and losses." In its Version 0 form, R1 was difficult or impossible to audit. The new version of the standard addresses this reliability concern through a modification to the definition of Reporting ACE requiring that Actual Net Interchange and Scheduled Net Interchange only include interchange with other BAAs. By modifying the definition of Reporting ACE it becomes impossible to exclude any generator, transmission, or load from all BAAs on an interconnection because exclusion from one BAA can only be accomplished by transferring that generator, transmission or load to an adjacent BAA. In addition, inadvertent accounting from the new BAL-005-1 R7 will reveal any problems between Scheduled Net Interchange as compared to Actual Net Interchange within a BAA.

In its evaluation considering the elimination of this requirement, the STD realized that there is no requirement that the BA be informed of the new facilities to be interconnected before the actual interconnection would take place. This puts the BA in the unreasonable position of having to adjust its operations for new unknown generation, transmission or load without advanced notice. The intent of the additions to R3 and R4 to FAC-001 is to insure that the BA receives advanced notice of the interconnection. This is a one-time requirement since the change in the definition of Reporting ACE addressed the intent of the original BAL-005-0 R1 and the ongoing reliability issue. The drafting team has modified the requirements in FAC-001-3 so that they only apply to new interconnecting facilities or facility modifications that would require material facility changes, and therefore material changes in the load to be balanced. The LSE has been removed from the standard based on the RBR initiative.

In FAC-001-2 R2, the words "upon request" are used in conjunction with the notification requirements. How does a BA know when to request such information? In FAC-001-2 R3, there is no specific mention of the BA. How does the TO know when the new load will affect the reliability functionality of the BA, or must the TO notify the BA for every request for interconnection? The new requirements were intended to remove the TO as the middleman for these requirements. TOP-003-3 includes the following words, "Each Balancing Authority shall retain evidence for three calendar years that it has distributed its data specification to entities that have data required by the Balancing Authority's analysis functions and Real-time monitoring in accordance with Requirement R4 and Measurement M4." How is the Balancing Authority to receive the knowledge that new load, generation or transmission is interconnecting so that it may distribute its data specification to entities that have data required by the Balancing Authority? This is the hole in the standards that modifications to FAC-001 R3 and R4 are intended to fill.

Response:

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Group Name: Duke Energy

Group Member Name	Entity	Region	Segments
Doug Hils	Duke Energy	RFC	1

Lee Schuster	Duke Energy	FRCC	3
Dale Goodwine	Duke Energy	SERC	5
Greg Cecil	Duke Energy	RFC	6

Selected Answer: Yes

Answer Comment: **Duke Energy requests further clarification on how the drafting team anticipates an entity will be required to demonstrate compliance with R5. As written, it does not appear that the proposed Requirements and Measures are in alignment. Currently, the requirements state that an entity (TO, GO, LSE) must confirm that a Facility is within a Balancing Authority Area's Metered Boundary, however, the measure suggests that an entity should point to a procedure to demonstrate compliance with R5, R6, and R7. We suggest that the drafting team revise the Measures to better align with what is being asked in the requirements, perhaps stating that an attestation letter from the BA would be adequate to demonstrate confirmation that an entity's Facility is within a BA Area's Metered Boundary.**

The SDT has modified FAC-001 to address your concerns. The LSE has been removed from the standard based on the RBR initiative.

Response:

Andrea Basinski - Puget Sound Energy, Inc. - 3 -

Selected Answer: No

Answer Comment:

As worded, we do not believe that BAL-005-0.2b Requirement R1 is appropriate for FAC-001-3. Since FAC-001-3 applies to documented Facility interconnection requirements, it would be more appropriate to require that the documented interconnection requirements contain language stating that transmission, generation and end-user interconnected Facilities must be located within the Balancing Authority Area's metered boundaries. This could be accomplished by adding R3.3 stating "Procedures for ensuring that transmission Facilities, generation Facilities and end-user Facilities are within the Balancing Authority Area's metered boundaries." The requirement to verify that existing facilities are located with the metered boundaries of a Balancing Authority Area is most appropriately assigned to the TOP, and not to the TO, GO and the LSE.

Response to Comments:

Requirement R1 from the Version 0 BAL-005 standard was originally included to meet the general requirement for Tie Line Bias Control to be effective. In the NERC Glossary of Terms, Reporting ACE requires that, "All portions of the Interconnection are included in one area [BAA] or another so that the sum of all area generation, loads and losses is the same as total system generation, load and losses." In its Version 0 form, R1 was difficult or impossible to audit. The new version of the standard addresses this reliability concern through a modification to the definition of Reporting ACE requiring that Actual Net Interchange and Scheduled Net Interchange only include interchange with other BAAs. By modifying the definition of Reporting ACE it becomes impossible to exclude any generator, transmission, or load from all BAAs on an interconnection because exclusion from one BAA can only be accomplished by transferring that generator, transmission or load to an adjacent BAA. In addition, inadvertent accounting from the new BAL-005-1 R7 will reveal any problems between Scheduled Net Interchange as compared to Actual Net Interchange within a BAA.

In its evaluation considering the elimination of this requirement, the STD realized that there is no requirement that the BA be informed of the new facilities to be interconnected before the actual interconnection would take place. This puts the BA in the unreasonable position of having to adjust its operations for new unknown generation, transmission or load without advanced notice. The intent of the additions to R3 and R4 to FAC-001 is to insure that the BA receives advanced notice of the interconnection. This is a one-time requirement since the change in the definition of Reporting ACE addressed the intent of the original BAL-005-0 R1 and the ongoing reliability issue. The drafting team has modified the requirements in FAC-001-3 so that they only apply to new interconnecting facilities or facility modifications that would require material facility changes, and therefore material changes in the load to be balanced. The LSE has been removed from the standard based on the RBR initiative.

Response:

Douglas Webb - Douglas Webb On Behalf of: Chris Bridges, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1
Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1
James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1
Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1

Selected Answer: No

Answer Comment: **KCP&L believes moving BAL-005-02.b R1 to FAC-001 should be rejected; it is an attempt to shoe-horn Requirements into an unrelated Standard, or, at**

best, marginally related Standard.

The FAC-001 Standard relates to entities seeking to interconnect with the Bulk Electric System. The Proposed FAC-001-3 and its predecessor versions' Purpose declaration state, "To avoid adverse impacts on the reliability of the Bulk Electric System, Transmission Owners and applicable Generator Owners must document and make Facility interconnection requirements available so that entities seeking to interconnect will have the necessary information."

It is unclear how Transmission Owners, Generation Owners, and Load-Serving Entities confirming they are within a Balancing Authority's metered boundaries relate to Generator Owners seeking interconnection with the Bulk Electric System. The FAC-001 Standard relates to new equipment planned to interconnect with the Bulk Electric System while BAL-005-02.b R1 relates to current and operational interconnections.

Additionally, the SAR discusses moving the TOP, LSE, and GOP from BAL-005-02.b (See SAR, pp. 4-5) to the FAC Standards. It is unclear where the TOP duties under R1 landed. It didn't land in FAC-001. Granted, the SAR is a framework and not binding, the language suggests the SDT was uncertain where to "put" the R1 Requirement. However, the Proposed FAC-001-3 R5 Violation Severity Level states, "The Transmission Operators with Transmission Facilities operating in an Interconnection…" In consideration of the VSL language and the proposed FAC-001-3 not expressly applicable to Transmission Operators, KCP&L is concerned that moving BAL-005-02.b R1 to FAC-001, creates an unstated duty for Transmission Operators.

Furthermore, the Proposed FAC-001-3 Purpose declaration is reiterated in Applicability Sec. 4.1.2.1., "Generator Owner with a fully executed

	Agreement to conduct a study on the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission system." **The FAC-001 Standard relates to new interconnects to the Bulk Electric System and should not be used as a landing pad for BAL-005 Requirements that no longer are relevant to BAL-005. KCP&L does not object to moving BAL-005 R1 to another Standard, but FAC-001 is not the appropriate Standard and the proposed changes should be reconsidered.** **Finally, in the event the changes to FAC-001-3 R5, R6, and R7 are endorsed by the stakeholders, KCP&L would ask language be added to FAC-001-3 to highlight it is applicable to new facilities, including the facilities identified in R5, R6, and R7.**
Response to Comment:	Requirement R1 from the Version 0 BAL-005 standard was originally included to meet the general requirement for Tie Line Bias Control to be effective. In the NERC Glossary of Terms, Reporting ACE requires that, "All portions of the Interconnection are included in one area [BAA] or another so that the sum of all area generation, loads and losses is the same as total system generation, load and losses." In its Version 0 form, R1 was difficult or impossible to audit. The new version of the standard addresses this reliability concern through a modification to the definition of Reporting ACE requiring that Actual Net Interchange and Scheduled Net Interchange only include interchange with other BAAs. By modifying the definition of Reporting ACE it becomes impossible to exclude any generator, transmission, or load from all BAAs on an interconnection because exclusion from one BAA can only be accomplished by transferring that generator, transmission or load to an adjacent BAA. In addition, inadvertent accounting from the new BAL-005-1

	R7 will reveal any problems between Scheduled Net Interchange as compared to Actual Net Interchange within a BAA. In its evaluation considering the elimination of this requirement, the STD realized that there is no requirement that the BA be informed of the new facilities to be interconnected before the actual interconnection would take place. This puts the BA in the unreasonable position of having to adjust its operations for new unknown generation, transmission or load without advanced notice. The intent of the additions to R3 and R4 to FAC-001 is to insure that the BA receives advanced notice of the interconnection. This is a one-time requirement since the change in the definition of Reporting ACE addressed the intent of the original BAL-005-0 R1 and the ongoing reliability issue. The drafting team has modified the requirements in FAC-001-3 so that they only apply to new interconnecting facilities or facility modifications that would require material facility changes, and therefore material changes in the load to be balanced. The LSE has been removed from the standard based on the RBR initiative. In FAC-001-2 R2, the words "upon request" are used in conjunction with the notification requirements. How does a BA know when to request such information? In FAC-001-2 R3, there is no specific mention of the BA. How does the TO know when the new load will affect the reliability functionality of the BA, or must the TO notify the BA for every request for interconnection? The new requirements were intended to remove the TO as the middleman for these requirements. TOP-003-3 includes the following words, "Each Balancing Authority shall retain evidence for three calendar years that it has distributed its data specification to entities that have data required by the Balancing Authority's analysis functions and Real-time monitoring in accordance with Requirement R4 and Measurement M4."

How is the Balancing Authority to receive the knowledge that new load, generation or transmission is interconnecting so that it may distribute its data specification to entities that have data required by the Balancing Authority? This is the hole in the standards that modifications to FAC-001 R3 and R4 are intended to fill.

Response:

Matthew Beilfuss - WEC Energy Group, Inc. - 3,4,5,6 - MRO,RFC

Selected Answer: Yes

Answer Comment: We agree with moving BAL-005-0.2b Requirement R1 to FAC-001 standard. However, given the likely retirement of the LSE functional role consideration should be given in the SAR to making the requirement applicable to the DP functional entity role.

Response to Comment: In its evaluation considering the elimination of this requirement, the STD realized that there is no requirement that the BA be informed of the new facilities to be interconnected before the actual interconnection would take place. This puts the BA in the unreasonable position of having to adjust its operations for new unknown generation, transmission or load without advanced notice. The intent of the additions to R3 and R4 to FAC-001 is to insure that the BA receives advanced notice of the interconnection. This is a one-time requirement since the change in the definition of Reporting ACE addressed the intent of the original BAL-005-0 R1 and the ongoing reliability issue. The drafting team has modified the requirements in FAC-001-3 so that they only apply to new interconnecting facilities or facility modifications that would require material facility changes, and therefore material changes in the load to be balanced. The LSE has been removed from the standard based on the RBR initiative.

Response:

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Group Name: NPCC--Project 2010-14.2.1 Phase 2 of Bal Auth Rel-based Controls - BAL-005-1, BAL-006-3, FAC-001-3

Group Member Name	Entity	Region	Segments
Alan Adamson	New York State Reliability Council, LLC	NPCC	10
David Burke	Orange and Rockland Utilities Inc.	NPCC	3
Greg Campoli	New York Independent System Operator	NPCC	2
Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
Mark Kenny	Northeast Utilities	NPCC	1
Helen Lainis	Independent Electricity System Operator	NPCC	2
Rob Vance	New Brunswick Power Corporation	NPCC	9
Paul Malozewski	Hydro One Networks Inc.	NPCC	1
Bruce Metruck	New York Power Authority	NPCC	6

Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
Brian Robinson	Utility Services	NPCC	8
Wayne Sipperly	New York Power Authority	NPCC	5
Edward Bedder	Orange and Rockland Utilities Inc.	NPCC	1
Michael Jones	National Grid	NPCC	1
Brian Shanahan	National Grid	NPCC	1
Glen Smith	Entergy Services, Inc.	NPCC	5
RuiDa Shu	Northeast Power Coordinating Council	NPCC	10
Connie Lowe	Dominion Resources Services, Inc.	NPCC	5
Guy Zito	Northeast Power Coordinating Council	NPCC	10
Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
Robert Pellegrini	The United Illuminating Company	NPCC	1
Kathleen Goodman	ISO - New England	NPCC	2

Selected Answer: No

Answer Comment:

Load Serving Entity (LSE) function: NERC provided FERC with justification to retire BAL-005-0.2b Part R1.3 for the LSE function (LSE function deregistration). Adding LSE requirements to FAC-001 does not appear to align with NERC's justification and the intent to retire BAL-005-0.2b R1.3.

FAC-001 Table of Compliance Elements: R5 and R6 reference Transmission Operator and Generation Operator, instead of Transmission Owner and Generator Owner.

The Purpose of FAC-001 is to "…make Facility interconnection requirements available so that entities seeking to interconnect will have the necessary information." Adding requirements to FAC-001 regarding metered boundaries appears to be misplaced. The proposed additions are ongoing requirements to confirm the metering of transmission facilities. The use of the word "confirm" is not the same as to establish the interconnection requirements.

Response to Comment:

Requirement R1 from the Version 0 BAL-005 standard was originally included to meet the general requirement for Tie Line Bias Control to be effective. In the NERC Glossary of Terms, Reporting ACE requires that, "All portions of the Interconnection are included in one area [BAA] or another so that the sum of all area generation, loads and losses is the same as total system generation, load and losses." In its Version 0 form, R1 was difficult or impossible to audit. The new version of the standard addresses this reliability concern through a modification to the definition of Reporting ACE requiring that Actual Net Interchange and Scheduled Net Interchange only include interchange with other BAAs. By modifying the definition of Reporting ACE it becomes impossible to exclude any generator, transmission, or load from all BAAs on an interconnection because exclusion from one BAA can only be accomplished by transferring that generator, transmission or load to an adjacent BAA. In addition, inadvertent accounting from the new BAL-005-1 R7 will reveal any problems between Scheduled Net Interchange as compared to Actual Net Interchange within a BAA.

In its evaluation considering the elimination of this requirement, the STD realized that there is no requirement that the BA be informed of the new facilities to be interconnected before the actual interconnection would take place. This puts the BA in the unreasonable position of having to adjust its operations for new unknown generation, transmission or load without advanced notice. The intent of the additions to R3 and R4 to FAC-001 is to insure that the BA receives advanced notice of the interconnection. This is a one-time requirement since the change in the definition of Reporting ACE addressed the intent of the original BAL-005-0 R1 and the ongoing reliability issue. The drafting team has modified the requirements in FAC-001-3 so that they only apply to new interconnecting facilities or facility modifications that would require material facility changes, and therefore material changes in the load to be balanced. The LSE has been removed from the standard based on the RBR initiative.

Response:

Likes: 1 Hydro One Networks, Inc., 1, Farahbakhsh Payam

Dislikes: 0

Jason Snodgrass - Georgia Transmission Corporation - 1 -

Selected Answer: No

Answer Comment: (1) FAC-001-2 was revised in 2013 to eliminate any requirements that were not necessary for reliability according to FERC paragraph 81 directions. As a member of the FAC-001-2 SDT charged with this task, GTC along with the other members followed the directives of FERC and retained only the requirements necessary for system reliability. As such 14 sub-requirements in FAC -001 were removed including a requirement for metering and telecommunication.

	Although GTC sees a merit in ensuring that the Area Control Error is calculated properly, GTC believes that the proposed requirements (FAC-001-3-R5, R6 and R7) does not resolve or address a reliability concern and would violate paragraph 81 criteria. Moreover GTC believe that requirements FAC-001-3-R5, R6 and R7 address specific needs for operating the system and therefore belong and already are included in Operations Standards such as TOP and IRO and not a Planning Standard associated with Facility interconnection Requirements. (2) As listed within this project's SAR, the Project 2010-14.2 BAL Standards PRT "believes that the requirements to identify the applicable BA should perhaps be in the interconnection agreements (via FERC's OATT or NAESB, for example)," we believe these requirements already do. Many other reliability requirements in the TOP and IRO standards support the identification of Interconnection Facilities through data modeling and specifications. For example, TOP-003-3 R4 identifies that "each Balancing Authority shall distribute its data specification to entities that have data required by the Balancing Authority's analysis functions and Real-time monitoring." TOP-003-3 applies to the same entities listed in the draft requirements.
Response to Comment:	Requirement R1 from the Version 0 BAL-005 standard was originally included to meet the general requirement for Tie Line Bias Control to be effective. In the NERC Glossary of Terms, Reporting ACE requires that, "All portions of the Interconnection are included in one area [BAA] or another so that the sum of all area generation, loads and losses is the same as total system generation, load and losses." In its Version 0 form, R1 was difficult or impossible to audit. The new version of the standard addresses this reliability concern through a

modification to the definition of Reporting ACE requiring that Actual Net Interchange and Scheduled Net Interchange only include interchange with other BAAs. By modifying the definition of Reporting ACE it becomes impossible to exclude any generator, transmission, or load from all BAAs on an interconnection because exclusion from one BAA can only be accomplished by transferring that generator, transmission or load to an adjacent BAA. In addition, inadvertent accounting from the new BAL-005-1 R7 will reveal any problems between Scheduled Net Interchange as compared to Actual Net Interchange within a BAA.

In its evaluation considering the elimination of this requirement, the STD realized that there is no requirement that the BA be informed of the new facilities to be interconnected before the actual interconnection would take place. This puts the BA in the unreasonable position of having to adjust its operations for new unknown generation, transmission or load without advanced notice. The intent of the additions to R3 and R4 to FAC-001 is to insure that the BA receives advanced notice of the interconnection. This is a one-time requirement since the change in the definition of Reporting ACE addressed the intent of the original BAL-005-0 R1 and the ongoing reliability issue. The drafting team has modified the requirements in FAC-001-3 so that they only apply to new interconnecting facilities or facility modifications that would require material facility changes, and therefore material changes in the load to be balanced.

In FAC-001-2 R2, the words “upon request” are used in conjunction with the notification requirements. How does a BA know when to request such information? In FAC-001-2 R3, there is no specific mention of the BA. How does the TO know when the new load will affect the reliability functionality of the BA, or must the TO notify the BA for every request for

	interconnection? The new requirements were intended to remove the TO as the middleman for these requirements. TOP-003-3 includes the following words, "Each Balancing Authority shall retain evidence for three calendar years that it has distributed its data specification to entities that have data required by the Balancing Authority's analysis functions and Real-time monitoring in accordance with Requirement R4 and Measurement M4." How is the Balancing Authority to receive the knowledge that new load, generation or transmission is interconnecting so that it may distribute its data specification to entities that have data required by the Balancing Authority? This is the hole in the standards that modifications to FAC-001 R3 and R4 are intended to fill.
Response:	

Mike ONeil - NextEra Energy - Florida Power and Light Co. - 1 -	
Selected Answer:	No
Answer Comment:	We appreciate the work by the SDT, but do not agree with moving BAL-005-0.2b Requirement R1 to FAC-001-3 Requirements R5, R6, and R7. At this time, the way the BAL-005 requirement R1 reads it poses to be more of an accounting issue versus a reliability issue. One alternative solution is to remove the language from this standard (FAC-001-3) and include it in the Application Guidelines section.
Response to Comment:	Requirement R1 from the Version 0 BAL-005 standard was originally included to meet the general requirement for Tie Line Bias Control to be effective. In

the NERC Glossary of Terms, Reporting ACE requires that, "All portions of the Interconnection are included in one area [BAA] or another so that the sum of all area generation, loads and losses is the same as total system generation, load and losses." In its Version 0 form, R1 was difficult or impossible to audit. The new version of the standard addresses this reliability concern through a modification to the definition of Reporting ACE requiring that Actual Net Interchange and Scheduled Net Interchange only include interchange with other BAAs. By modifying the definition of Reporting ACE it becomes impossible to exclude any generator, transmission, or load from all BAAs on an interconnection because exclusion from one BAA can only be accomplished by transferring that generator, transmission or load to an adjacent BAA. In addition, inadvertent accounting from the new BAL-005-1 R7 will reveal any problems between Scheduled Net Interchange as compared to Actual Net Interchange within a BAA.

In its evaluation considering the elimination of this requirement, the STD realized that there is no requirement that the BA be informed of the new facilities to be interconnected before the actual interconnection would take place. This puts the BA in the unreasonable position of having to adjust its operations for new unknown generation, transmission or load without advanced notice. The intent of the additions to R3 and R4 to FAC-001 is to insure that the BA receives advanced notice of the interconnection. This is a one-time requirement since the change in the definition of Reporting ACE addressed the intent of the original BAL-005-0 R1 and the ongoing reliability issue. The drafting team has modified the requirements in FAC-001-3 so that they only apply to new interconnecting facilities or facility modifications that would require material facility changes, and therefore material changes in the load to be balanced.

In FAC-001-2 R2, the words “upon request” are used in conjunction with the notification requirements. How does a BA know when to request such information? In FAC-001-2 R3, there is no specific mention of the BA. How does the TO know when the new load will affect the reliability functionality of the BA, or must the TO notify the BA for every request for interconnection? The new requirements were intended to remove the TO as the middleman for these requirements. TOP-003-3 includes the following words, “Each Balancing Authority shall retain evidence for three calendar years that it has distributed its data specification to entities that have data required by the Balancing Authority’s analysis functions and Real-time monitoring in accordance with Requirement R4 and Measurement M4.” How is the Balancing Authority to receive the knowledge that new load, generation or transmission is interconnecting so that it may distribute its data specification to entities that have data required by the Balancing Authority? This is the hole in the standards that modifications to FAC-001 R3 and R4 are intended to fill.

Response:

Payam Farahbakhsh - Hydro One Networks, Inc. - 1 -

Selected Answer: No

Albert DiCaprio - PJM Interconnection, L.L.C. - 2 - RFC

Group Name: ISO Standards Review Committee

Group Member Name	Entity	Region	Segments
Charles Yeung	SPP	SPP	2
Ben Li	IESO	NPCC	2
Mark Holman	PJM	RFC	2
Kathleen Goodman	ISONE	NPCC	2
Greg Campoli	NYISO	NPCC	2
Ali Miremadi	CAISO	WECC	2
Terry Bilke	MISO	RFC	2
Christina Bigelow	ERCOT	TRE	2

Selected Answer: No

Answer Comment: The SRC supports deleting the R1 requirements in BAL-005-0.2b, and recommends placing the obligation in a certification requirement.

See file attached to Question 1 for the full text of the comments to Question 2

Response to Comment: Requirement R1 from the Version 0 BAL-005 standard was originally included to meet the general requirement for Tie Line Bias Control to be effective. In the NERC Glossary of Terms, Reporting ACE requires that, "All portions of the Interconnection are included in one area [BAA] or another so that the sum of all area generation, loads and losses is the same as total system generation, load and losses." In its Version 0 form, R1 was difficult or impossible to audit. The new version of the standard addresses this reliability concern through a modification to the definition of Reporting ACE requiring that Actual Net Interchange and Scheduled Net Interchange only include interchange with other BAAs. By modifying the definition of Reporting ACE it becomes impossible to exclude any generator, transmission, or load from all BAAs on an interconnection because exclusion from one BAA can only be accomplished by transferring that generator, transmission or load to an adjacent BAA. In addition, inadvertent accounting from the new BAL-005-1 R7 will reveal any problems between Scheduled Net Interchange as compared to Actual Net Interchange within a BAA.

In its evaluation considering the elimination of this requirement, the STD realized that there is no requirement that the BA be informed of the new facilities to be interconnected before the actual interconnection would take place. This puts the BA in the unreasonable position of having to adjust its operations for new unknown generation, transmission or load without advanced notice. The intent of the additions to R3 and R4 to FAC-001 is to insure that the BA receives advanced notice of the interconnection. This is a one-time requirement since the change in the definition of Reporting ACE addressed the intent of the original BAL-005-0 R1 and the ongoing reliability issue. The drafting team has modified the requirements in FAC-001-3 so that they only apply to new interconnecting facilities or facility modifications that would require material facility changes, and therefore material changes in the load to be balanced.

In FAC-001-2 R2, the words "upon request" are used in conjunction with the notification requirements. How does a BA know when to request such information? In FAC-001-2 R3, there is no specific mention of the BA. How does the TO know when the new load will affect the reliability functionality of the BA, or must the TO notify the BA for every request for interconnection? The new requirements were intended to remove the TO as the middleman for these requirements. TOP-003-3 includes the following words, "Each Balancing Authority shall retain evidence for three calendar years that it has distributed its data specification to entities that have data required by the Balancing Authority's analysis functions and Real-time monitoring in accordance with Requirement R4 and Measurement M4." How is the Balancing Authority to receive the knowledge that new load, generation or transmission is interconnecting so that it may distribute its data specification to entities that have data required by the Balancing Authority? This is the hole in the standards that modifications to FAC-001 R3 and R4 are intended to fill.

Response:

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer: Yes

Shawna Speer - Colorado Springs Utilities - 1 -

Group Name: Colorado Springs Utilities

Group Member Name	Entity	Region	Segments
Shawna Speer	Colorado Springs Utilities	WECC	1
Shannon Fair	Colorado Springs Utilities	WECC	6
Charles Morgan	Colorado Springs Utilities	WECC	3
Kaleb Brimhall	Colorado Springs Utilities	WECC	5

Selected Answer: No

Answer Comment:

The FAC-001 standard is used to facilitate interconnection requirements for those **entities seeking interconnection** into the **BES.** In the draft FAC-001-3 Requirements R5-R7 the language speaks to those who entities who are already operating in an interconnection and therefore does not fit the purpose of this standard. The FAC-001 standard cannot be used to enforce R5 –R7 for those facilities that already exist.

The LSE function should not be included in the FAC-001 standard and therefore R7 should be removed in its entirety from the draft. In R7, it is not clear if the LSE, TO, or GO will be required to address this in their interconnection requirements. There is no requirement for an LSE to have documented facility interconnection requirements.

Response to Comment:

In its evaluation considering the elimination of this requirement, the STD realized that there is no requirement that the BA be informed of the new facilities to be interconnected before the actual interconnection would take place. This puts the BA in the unreasonable position of having to adjust its operations for new unknown generation, transmission or load without advanced notice. The intent of the additions to R3 and R4 to FAC-001 is to insure that the BA receives advanced notice of the interconnection. This is a one-time requirement since the change in the definition of Reporting ACE addressed the intent of the original BAL-005-0 R1 and the ongoing reliability issue. The drafting team has modified the requirements in FAC-001-3 so that they only apply to new interconnecting facilities or facility modifications that would require material facility changes, and therefore material changes in the load to be balanced. The LSE has been removed from the standard based on the RBR initiative.

Answer Comment:

To truly make this consistent with the purpose of the FAC-001 standard the wording should be revised to address the documented facility interconnection requirements. The draft standard should require that the TO & Applicable GO facility interconnection requirements address BAA metered bounds for those entities seeking interconnection. The entities seeking interconnection should determine their operating area and therefore BAA metered bounds from their desired interconnection location.

CSU is of the opinion that these requirements belong in the INT or TOP family of Standards.

Response to Comment:

Requirement R1 from the Version 0 BAL-005 standard was originally included to meet the general requirement for Tie Line Bias Control to be effective. In the NERC Glossary of Terms, Reporting ACE requires that, "All portions of the Interconnection are included in one area [BAA] or another so that the sum of all area generation, loads and losses is the same as total system generation, load and losses." In its Version 0 form, R1 was difficult or impossible to audit. The new version of the standard addresses this reliability concern through a modification to the definition of Reporting ACE requiring that Actual Net Interchange and Scheduled Net Interchange only include interchange with other BAAs. By modifying the definition of Reporting ACE it becomes impossible to exclude any generator, transmission, or load from all BAAs on an interconnection because exclusion from one BAA can only be accomplished by transferring that generator, transmission or load to an adjacent BAA. In addition, inadvertent accounting from the new BAL-005-1 R7 will reveal any problems between Scheduled Net Interchange as compared to Actual Net Interchange within a BAA.

Response:

Jason Smith - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool	SPP	2
Jason Smith	Southwest Power Pool	SPP	2
Ashley Stringer	Oklahoma Municipal Power Authority	SPP	4

Selected Answer: No

Answer Comment: These requirements do not rise to the level of needing a continuously audited Reliability Standard. Once a facility is interconnected and certified, then the inclusion within a BA's metered bounds should be verified at that time. There should not be a need for continuing certification that it remains within the metered bounds. The requirements as stated only result in administrative efforts and are an exercise in submitting attestations.

One suggestion would be to simply add a sub-requirement that the Transmission Owner's Interconnection Requirements (FAC-001-3 R1) must include a requirement that all interconnected facilities must be demonstrated to be within a Balancing Authority's metered boundaries. Then there would be no need for the new, proposed R5-R7. This puts the compliance effort into ensuring the facility is metered properly upon interconnection – to satisfy the TO Facility Interconnection

	Requirements – rather than an ongoing verification that the facilities continue to be within the metered bounds.
Response to Comment:	The drafting team has modified the requirements in FAC-001-3 so that they only apply to new interconnecting facilities or facility modifications that would require material facility changes, and therefore material changes in the load to be balanced.
Response:	

Erika Doot - U.S. Bureau of Reclamation - 5 -	
Selected Answer:	No
Answer Comment:	Reclamation recommends that the drafting team propose to retire BAL-005-0.2b R1 instead of moving the requirement into FAC-001-3. Reclamation does not believe that the drafting team has addressed the Periodic Review Team's recommendation to identify "what is needed for ensuring facilities are within a Balancing Authority Area prior to MW being generated or consumed." Like the existing requirement, the proposed requirement does not mention verifying that facilities are within the metered boundaries of a Balancing Authority Area "prior to transmission operation, resource operation, or load being served." Therefore, the proposed requirement perpetuates a paperwork burden that costs staff time and resources of Generator Operators, Transmission Operators, and Load Serving Entities with longstanding arrangements with their host Balancing Authority. Registered Entities acquiring letters to confirm that they are in the

	metered boundaries of a Balancing Authority Area provides no benefit to system reliability.
Response to Comment:	Requirement R1 from the Version 0 BAL-005 standard was originally included to meet the general requirement for Tie Line Bias Control to be effective. In the NERC Glossary of Terms, Reporting ACE requires that, "All portions of the Interconnection are included in one area [BAA] or another so that the sum of all area generation, loads and losses is the same as total system generation, load and losses." In its Version 0 form, R1 was difficult or impossible to audit. The new version of the standard addresses this reliability concern through a modification to the definition of Reporting ACE requiring that Actual Net Interchange and Scheduled Net Interchange only include interchange with other BAAs. By modifying the definition of Reporting ACE it becomes impossible to exclude any generator, transmission, or load from all BAAs on an interconnection because exclusion from one BAA can only be accomplished by transferring that generator, transmission or load to an adjacent BAA. In addition, inadvertent accounting from the new BAL-005-1 R7 will reveal any problems between Scheduled Net Interchange as compared to Actual Net Interchange within a BAA. In its evaluation considering the elimination of this requirement, the STD realized that there is no requirement that the BA be informed of the new facilities to be interconnected before the actual interconnection would take place. This puts the BA in the unreasonable position of having to adjust its operations for new unknown generation, transmission or load without advanced notice. The intent of the additions to R3 and R4 to FAC-001 is to insure that the BA receives advanced notice of the interconnection. This is a one-time requirement since the change in the definition of Reporting ACE addressed the intent of the original BAL-005-0 R1 and the ongoing reliability issue. The drafting team has modified the requirements in FAC-001-3 so that

they only apply to new interconnecting facilities or facility modifications that would require material facility changes, and therefore material changes in the load to be balanced.

3. The SDT has moved the BAL-006-2 Requirement R3 into BAL-005-3 since this requirement directly impacts an entity's ability to calculate an accurate Reporting ACE. Do you agree with moving this requirement into the proposed BAL-005-1 standard? If not, please explain in the comment area below.

John Fontenot - Bryan Texas Utilities - 1 -	
Selected Answer:	Yes
Andrew Pusztai - American Transmission Company, LLC - 1 -	
Selected Answer:	Yes
Nick Vtyurin - Manitoba Hydro - 1,3,5,6 – MRO	
Selected Answer:	Yes
Thomas Foltz - AEP - 5 -	
Selected Answer:	Yes
Leonard Kula - Independent Electricity System Operator - 2 -	

Selected Answer: Yes

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Group Name: MRO-NERC Standards Review Forum (NSRF)

Group Member Name	Entity	Region	Segments
Joe Depoorter	Madison Gas & Electric	MRO	3,4,5,6
Amy Casucelli	Xcel Energy	MRO	1,3,5,6
Chuck Lawrence	American Transmission Company	MRO	1
Chuck Wicklund	Otter Tail Power Company	MRO	1,3,5
Theresa Allard	Minnkota Power Cooperative, Inc	MRO	1,3,5,6
Dave Rudolph	Basin Electric Power Cooperative	MRO	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5,6
Jodi Jenson	Western Area Power Administration	MRO	1,6
Larry Heckert	Alliant Energy	MRO	4
Mahmood Safi	Omaha Public Utility District	MRO	1,3,5,6
Shannon Weaver	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Brad Perrett	Minnesota Power	MRO	1,5
Scott Nickels	Rochester Public Utilities	MRO	4
Terry Harbour	MidAmerican Energy Company	MRO	1,3,5,6
Tom Breene	Wisconsin Public Service Corporation	MRO	3,4,5,6
Tony Eddleman	Nebraska Public Power District	MRO	1,3,5

Selected Answer: No

Answer Comment:

MWHr meters are for Inadvertent Interchange accounting. Making this change will confuse the issue and will add unnecessary obligations. As long as the two BAs use common metering, any minor error in reporting ACE is contained between them and has no impact on the Interconnection as a whole.

The scan-rate accuracy of Reporting ACE is critical to the effectiveness of Tie Line Bias Control and the accuracy of the performance measures based on Reporting ACE, i.e. CPS1, BAAL, DCS, and FRM. The hourly MWhs telemetered to each EMS from the tie line meters and agreed to by the Adjacent BAAs is required to be available and may be in the Operating Process to identify and mitigate errors affecting the accuracy of scan-rate data used in the calculation of Reporting ACE for each Balancing Authority Area. These errors are usually between integrated hourly scan-rate data and hourly accumulated meter data but can also occur as differences between the accumulated meter data of two adjacent BAAs.

Unfortunately, scan-rate values cannot be directly compared with each other because of differences between scan times and differences in scan-rates between BAAs. This Operating Process could include analysis of two different data comparisons for each Adjacent BAA for each tie line. These data comparisons are:

1. The comparison of scan-rate data integrated over each hour with the MWh accumulated values telemetered separately for each tie line each hour for the first BAA.

2. The comparison of the MWh accumulated values telemetered separately with the MWh values agreed upon by the two adjacent BAAs.

If errors resulting from one of these data comparisons is excluded from the error identification and mitigation process, the errors excluded will be also be excluded from the performance measurements and responsibility for managing these excluded errors will be passed to the interconnection. This will result in frequency control error managed by all BAAs through the frequency bias terms of their Reporting ACE.

Response:

Terry BIlke - Midcontinent ISO, Inc. - 2 -

Selected Answer: No

Answer Comment: MWHr meters are for Inadvertent Interchange accounting. There are already other requirements proposed that deal with making sure ACE is realatively accurate. Additionally, as long as adjacent BAs use common metering, any minor error in reporting ACE is contained between them and has no impact on the Interconnection as a whole.

The scan-rate accuracy of Reporting ACE is critical to the effectiveness of Tie Line Bias Control and the accuracy of the performance measures based on Reporting ACE, i.e. CPS1, BAAL, DCS, and FRM. The hourly MWhs telemetered to each EMS from the tie line meters and agreed to by the Adjacent BAAs is required to be available and may be in the Operating Process to identify and mitigate errors affecting the accuracy of scan-rate data used in the calculation of Reporting ACE for each Balancing Authority Area. These errors are usually between integrated hourly scan-rate data and hourly accumulated meter data but can also occur as differences between the accumulated meter data of two adjacent BAAs.

Unfortunately, scan-rate values cannot be directly compared with each other because of differences between scan times and differences in scan-rates between BAAs. This Operating Process could include analysis of two different data comparisons for each Adjacent BAA for each tie line. These data comparisons are:

1. The comparison of scan-rate data integrated over each hour with the MWh accumulated values telemetered separately for each tie line each hour for the first BAA.
2. The comparison of the MWh accumulated values telemetered separately with the MWh values agreed upon by the two adjacent BAAs.

If errors resulting from one of these data comparisons is excluded from the error identification and mitigation process, the errors excluded will be also be excluded from the performance measurements and responsibility for managing these excluded errors will be passed to the interconnection. This will result in frequency control error managed by all BAAs through the frequency bias terms of their Reporting ACE.

Response:

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Selected Answer:	No
Answer Comment:	MWHr meters are for Inadventent Interchange accounting. Making the proposed change could lead to confustion and unnecessary obligations. If the two BAs use common metering, any minor error in ACE reporting is contained and would have no impact on the Interconnection as a whole.

The scan-rate accuracy of Reporting ACE is critical to the effectiveness of Tie Line Bias Control and the accuracy of the performance measures based on Reporting ACE, i.e. CPS1, BAAL, DCS, and FRM. The hourly MWhs telemetered to each EMS from the tie line meters and agreed to by the Adjacent BAAs is required to be available and may be in the Operating Process to identify and mitigate errors affecting the accuracy of scan-rate data used in the calculation of Reporting ACE for each Balancing Authority Area. These errors are usually between integrated hourly scan-rate data and hourly accumulated meter data but can also occur as differences between the accumulated meter data of two adjacent BAAs.

Unfortunately, scan-rate values cannot be directly compared with each other because of differences between scan times and differences in scan-rates between BAAs. This Operating Process could include analysis of two different data comparisons for each Adjacent BAA for each tie line. These data comparisons are:

1. The comparison of scan-rate data integrated over each hour with the MWh accumulated values telemetered separately for each tie line each hour for the first BAA.
2. The comparison of the MWh accumulated values telemetered separately with the MWh values agreed upon by the two adjacent BAAs.

If errors resulting from one of these data comparisons is excluded from the error identification and mitigation process, the errors excluded will be also be excluded from the performance measurements and responsibility for managing these excluded errors will be passed to the interconnection. This will result in frequency control error managed by all BAAs through the frequency bias terms of their Reporting ACE.

Response:

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert Schaffeld	Southern Company Services, Inc	SERC	1

John Ciza	Southern Company Generation and Energy Marketing	SERC	6
R Scott Moore	Alabama Power Company	SERC	3
William Shultz	Southern Company Generation	SERC	5

Selected Answer: Yes

Eleanor Ewry - Puget Sound Energy, Inc. - 1,3,5 - WECC

Selected Answer: Yes

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable

Group Name: ACES Standards Collaborators

Group Member Name	Entity	Region	Segments
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Bill Hutchison	Southern Illinois Power Cooperative	SERC	1
Michael Brytowski	Great River Energy	MRO	1,3,5,6
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
John Shaver	Arizona Electric Power Cooperative, Inc.	WECC	4,5

John Shaver	Southwest Transmission Cooperative, Inc.	WECC	1
Ryan Strom	Buckeye Power, Inc.	RFC	4
Scott Brame	North Carolina Electric Membership Corporation	SERC	3,4,5
Bill Watson	Old Dominion Electric Cooperative	SERC	3,4

Selected Answer: Yes

Answer Comment: We concur with the SDT's recommendation, as BAL-005-1 addresses more proactive and real-time AGC operations while BAL-006 addresses more after-the-fact.

Thank you for your comments.

Response:

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer: No

Answer Comment: Texas RE noticed there is no redline for BAL-005-1. Redlines are helpful in reviewing revisions.

Texas RE noticed BAL-006-2 R3 has the phrase "with readings provided ***hourly***" (emphasis added) which, dictates a timing aspect. BAL-005-1 R1 has the phrase "to determine hourly megawatt-hour values" but does not have a time aspect specifically required. Texas RE inquires

	whether this was the intent of the SDT (and Texas RE is aware of the expected historical practice of hourly communications between entities). The SDT elected not to provide a red-line since it was not meaningful and more confusing. The Operating Process will determine the time-frame for distribution of the required information between adjacent BAAs.
Response:	
John Fontenot - Bryan Texas Utilities - 1 -	
Selected Answer:	Yes
David Jendras - Ameren - Ameren Services - 3 -	
Selected Answer:	No
Answer Comment:	**Ameren supports MISO's comments for this question** Please refer to the response to the MISO comments.
Response:	

Carol Chinn - Florida Municipal Power Agency - 4 -

Group Name: FMPA

Group Member Name	Entity	Region	Segments
Tim Beyrle	City of New Smyrna Beach	FRCC	4
Jim Howard	Lakeland Electric	FRCC	3
Greg Woessner	Kissimmee Utility Authority	FRCC	3
Lynne Mila	City of Clewiston	FRCC	3
Javier Cisneros	Fort Pierce Utility Authority	FRCC	4
Randy Hahn	Ocala Utility Services	FRCC	3
Don Cuevas	Beaches Energy Services	FRCC	1
Stan Rzad	Keys Energy Services	FRCC	4
Matt Culverhouse	City of Bartow	FRCC	3
Tom Reedy	Florida Municipal Power Pool	FRCC	6
Steven Lancaster	Beaches Energy Services	FRCC	3
Mike Blough	Kissimmee Utility Authority	FRCC	5
Mark Brown	City of Winter Park	FRCC	3
Mace Hunter	Lakeland Electric	FRCC	3

Selected Answer: No

Answer Comment: FMPA agrees removing R3 from BAL-006, but it seems to have created duplicative requirements in BAL-005. Requirements R1 and R8 should be combined.

The SDT has modified the proposed standard to accommodate your recommendations.

Response:

Mark Holman - PJM Interconnection, L.L.C. - 2 -

Selected Answer: No

Answer Comment:

The standard states that the purpose is for acquiring data to calculate Reporting ACE. R1 does not fall under that category as it is currently written. It states its purpose is to determine MWh values. PJM suggests the following change to the R1 to align with the purpose of BAL-005:

R1. Each Balancing Authority shall ensure that each Tie-Line, Pseudo-Tie, and Dynamic Schedule with an Adjacent Balancing Authority is equipped with a mutually agreed- upon time synchronized common source. to determine hourly megawatt-hour values.

While PJM agrees it is important to maintain a requirement to calculate MWh values for Inadvertent Interchange, PJM suggest this be moved to a NAESB standard.

The scan-rate accuracy of Reporting ACE is critical to the effectiveness of Tie Line Bias Control and the accuracy of the performance measures based on Reporting ACE, i.e. CPS1, BAAL, DCS, and FRM. The hourly MWhs telemetered to each EMS from the tie line meters and agreed to by the Adjacent BAAs is required to be available and may be in the Operating Process to identify and mitigate errors affecting the accuracy of scan-rate data used in the calculation of Reporting ACE for each Balancing Authority Area. These errors are usually between integrated hourly scan-rate data and hourly accumulated meter data but can also occur as differences between the accumulated meter data of two adjacent BAAs.

Unfortunately, scan-rate values cannot be directly compared with each other because of differences between scan times and differences in scan-rates between BAAs. This Operating Process could include analysis of two different data comparisons for each Adjacent BAA for each tie line. These data comparisons are:

1. The comparison of scan-rate data integrated over each hour with the MWh accumulated values telemetered separately for each tie line each hour for the first BAA.
2. The comparison of the MWh accumulated values telemetered separately with the MWh values agreed upon by the two adjacent BAAs.

If errors resulting from one of these data comparisons is excluded from the error identification and mitigation process, the errors excluded will be also be excluded from the performance measurements and responsibility for managing these excluded errors will be passed to the interconnection. This will result in frequency control error managed by all BAAs through the frequency bias terms of their Reporting ACE.

Response:

Chantal Mazza - Hydro-Qu?bec TransEnergie - 2 – NPCC

Selected Answer: No

Answer Comment: For the Quebec Interconnection, it makes more sense for metering issues to be in BAL-006 than BAL-005 since as a single BA asynchronous Interconnection, Net Interchanges are not calculated in our ACE. However HQ understands that our situation is exceptional and do not oppose the move of BAL-006-2 R3 to BAL-005-1.

Response: Thank you for your comment.

Theresa Rakowsky - Puget Sound Energy, Inc. - 1 -

Selected Answer: Yes

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Group Name: Duke Energy

Group Member Name	Entity	Region	Segments

Doug Hils	Duke Energy	RFC	1
Lee Schuster	Duke Energy	FRCC	3
Dale Goodwine	Duke Energy	SERC	5
Greg Cecil	Duke Energy	RFC	6

Selected Answer: Yes

Answer Comment: **Duke Energy agrees with the move to BAL-005-1, however, we recommend that the drafting team revise the Measure for R1 to better align with R1.1. The sub-requirement R1.1 states that megawatt-hour values must be exchanged between Adjacent Balancing Authorities. The Measure provides guidance for R1, but does not provide guidance or example of demonstrating compliance with R1.1. More information is needed to outline how an entity is expected to demonstrate that the exchange of values took place, and how often must the exchange take place.**

Thank you for your comment. The SDT has made modifications to both the proposed standard and the measurements.

Response:

Douglas Webb - Douglas Webb On Behalf of: Chris Bridges, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1
Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1
James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1
Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1

Selected Answer: Yes

Matthew Beilfuss - WEC Energy Group, Inc. - 3,4,5,6 - MRO,RFC

Selected Answer: Yes

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Group Name: NPCC--Project 2010-14.2.1 Phase 2 of Bal Auth Rel-based Controls - BAL-005-1, BAL-006-3, FAC-001-3

Group Member Name	Entity	Region	Segments
Alan Adamson	New York State Reliability Council, LLC	NPCC	10
David Burke	Orange and Rockland Utilities Inc.	NPCC	3
Greg Campoli	New York Independent System Operator	NPCC	2
Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
Mark Kenny	Northeast Utilities	NPCC	1
Helen Lainis	Independent Electricity System Operator	NPCC	2
Rob Vance	New Brunswick Power Corporation	NPCC	9
Paul Malozewski	Hydro One Networks Inc.	NPCC	1
Bruce Metruck	New York Power Authority	NPCC	6

Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
Brian Robinson	Utility Services	NPCC	8
Wayne Sipperly	New York Power Authority	NPCC	5
Edward Bedder	Orange and Rockland Utilities Inc.	NPCC	1
Michael Jones	National Grid	NPCC	1
Brian Shanahan	National Grid	NPCC	1
Glen Smith	Entergy Services, Inc.	NPCC	5
RuiDa Shu	Northeast Power Coordinating Council	NPCC	10
Connie Lowe	Dominion Resources Services, Inc.	NPCC	5
Guy Zito	Northeast Power Coordinating Council	NPCC	10
Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
Robert Pellegrini	The United Illuminating Company	NPCC	1
Kathleen Goodman	ISO - New England	NPCC	2

Selected Answer: No

Answer Comment: BAL-006-2--

R3. Each Balancing Authority shall ensure all of its Balancing Authority Area interconnection points are equipped with **common** megawatt-hour meters, with readings provided hourly to the control centers of Adjacent Balancing Authorities.

Is there a requirement for hourly reporting? What is meant by "common"? Is this a certification issue, or an Interconnection Agreement issue, or a standard?

The scan-rate accuracy of Reporting ACE is critical to the effectiveness of Tie Line Bias Control and the accuracy of the performance measures based on Reporting ACE, i.e. CPS1, BAAL, DCS, and FRM. The hourly MWhs telemetered to each EMS from the tie line meters and agreed to by the Adjacent BAAs is required to be available and may be in the Operating Process to identify and mitigate errors affecting the accuracy of scan-rate data used in the calculation of Reporting ACE for each Balancing Authority Area. These errors are usually between integrated hourly scan-rate data and hourly accumulated meter data but can also occur as differences between the accumulated meter data of two adjacent BAAs.

Unfortunately, scan-rate values cannot be directly compared with each other because of differences between scan times and differences in scan-rates between BAAs. This Operating Process could include analysis of two different data comparisons for each Adjacent BAA for each tie line. These data comparisons are:

1. The comparison of scan-rate data integrated over each hour with the MWh accumulated values telemetered separately for each tie line each hour for the first BAA.
2. The comparison of the MWh accumulated values telemetered separately with the MWh values agreed upon by the two adjacent BAAs.

If errors resulting from one of these data comparisons is excluded from the error identification and mitigation process, the errors excluded will be also be excluded from the performance measurements and responsibility for managing these excluded errors will be passed to the interconnection. This will result in frequency control error managed by all BAAs through the frequency bias terms of their Reporting ACE.

Response:

Mike ONeil - NextEra Energy - Florida Power and Light Co. - 1 -

Selected Answer: Yes

Payam Farahbakhsh - Hydro One Networks, Inc. - 1 -

Selected Answer: No

Albert DiCaprio - PJM Interconnection, L.L.C. - 2 - RFC

Group Name: ISO Standards Review Committee

Group Member Name	Entity	Region	Segments
Charles Yeung	SPP	SPP	2
Ben Li	IESO	NPCC	2
Mark Holman	PJM	RFC	2
Kathleen Goodman	ISONE	NPCC	2

Greg Campoli	NYISO	NPCC	2
Ali Miremadi	CAISO	WECC	2
Terry Bilke	MISO	RFC	2
Christina Bigelow	ERCOT	TRE	2

Selected Answer: No

Answer Comment: The SRC opposes the proposal to move BAL-006-2 Requirement R3 into BAL-005-3.

The SRC recommends that BAL-006 be deleted.

See file attached to Question 1 for the full text of the comments to Question 3

The scan-rate accuracy of Reporting ACE is critical to the effectiveness of Tie Line Bias Control and the accuracy of the performance measures based on Reporting ACE, i.e. CPS1, BAAL, DCS, and FRM. The hourly MWhs telemetered to each EMS from the tie line meters and agreed to by the Adjacent BAAs is required to be available and may be in the Operating Process to identify and mitigate errors affecting the accuracy of scan-rate data used in the calculation of Reporting ACE for each Balancing Authority Area. These errors are usually between integrated hourly scan-rate data and hourly accumulated meter data but can also occur as differences between the accumulated meter data of two adjacent BAAs.

Unfortunately, scan-rate values cannot be directly compared with each other because of differences between scan times and differences in scan-rates between BAAs. This Operating Process could include analysis of two different data comparisons for each Adjacent BAA for each tie line. These data comparisons are:

1. The comparison of scan-rate data integrated over each hour with the MWh accumulated values telemetered separately for each tie line each hour for the first BAA.
2. The comparison of the MWh accumulated values telemetered separately with the MWh values agreed upon by the two adjacent BAAs.

If errors resulting from one of these data comparisons is excluded from the error identification and mitigation process, the errors excluded will be also be excluded from the performance measurements and responsibility for managing these excluded errors will be passed to the interconnection. This will result in frequency control error managed by all BAAs through the frequency bias terms of their Reporting ACE.

Response:

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer: Yes

Jason Smith - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool	SPP	2
Jason Smith	Southwest Power Pool	SPP	2
Ashley Stringer	Oklahoma Municipal Power Authority	SPP	4

Selected Answer: Yes

Answer Comment:

The change from BAL-006-2 R3 to BAL-005-1 R1 and R8 seem to be a step in the right direction. The measures however (BAL-005-1 M1) seems to only require evidence that a common source was agreed upon, not that the data values were actually exchanged between Adjacent BA's in a timely manner. If the intent is only to ensure a common source was identified, then that should be done in certification and does not rise to a Reliability Standard.

The need for common megawatt-hour meters between BAs serves only to account for inadvertent interchange between those entities. Accumulated inadvertent is not related to real-time reliability. Proposed BAL-005-1 R1 should be removed.

The scan-rate accuracy of Reporting ACE is critical to the effectiveness of Tie Line Bias Control and the accuracy of the performance measures based on Reporting ACE, i.e. CPS1, BAAL, DCS, and FRM. The hourly MWhs telemetered to each EMS from the tie line meters and agreed to by the Adjacent BAAs is required to be available and may be in the Operating Process to identify and mitigate errors affecting the accuracy of scan-rate data used in the calculation of Reporting ACE for each Balancing Authority Area. These errors are usually between integrated hourly scan-rate data and hourly accumulated meter data but can also occur as differences between the accumulated meter data of two adjacent BAAs.

Unfortunately, scan-rate values cannot be directly compared with each other because of differences between scan times and differences in scan-rates between BAAs. This Operating Process could include analysis of two different data comparisons for each Adjacent BAA for each tie line. These data comparisons are:

1. The comparison of scan-rate data integrated over each hour with the MWh accumulated values telemetered separately for each tie line each hour for the first BAA.
2. The comparison of the MWh accumulated values telemetered separately with the MWh values agreed upon by the two adjacent BAAs.

If errors resulting from one of these data comparisons is excluded from the error identification and mitigation process, the errors excluded will be also be excluded from the performance measurements and responsibility for managing these excluded errors will be passed to the interconnection. This will result in frequency control error managed by all BAAs through the frequency bias terms of their Reporting ACE.

Response:

Erika Doot - U.S. Bureau of Reclamation - 5 -

Selected Answer: Yes

4. Please provide any issues you have on this draft of the BAL-005-1 standard and a proposed solution.

John Fontenot - Bryan Texas Utilities - 1 -	
Answer Comment:	none
Leonard Kula - Independent Electricity System Operator - 2 -	
Answer Comment:	**Notwithstanding our comments on selected requirements provided below, as an overall comment we do not believe some of the proposed requirements belong to a Reliability Standard. We believe Requirements R2, R4, R5 and R6 are more suited for inclusion in the Organization Certification Requirement for Balancing Authorities since these requirements stipulate the capabilities and facilities that need to be in place to enable a BA to perform its tasks. These are "one-off" requirements that do not drive continuous behaviors, and they do not require frequent updates.** These requirements have been reviewed by the Periodic Review Team and found to be necessary to remain as Reliability Standard requirements. The Drafting Team concurs.

In response to the comment of lack of continuous behaviors and infrequent updates nullifying these requirements, the Drafting Team would ask what NERC procedural document is being referenced to determine these as thresholds for valid requirements. Many NERC requirements occur annually or upon request. Additionally, the Drafting Team does not agree that these are "one-off" requirements that do not need to be continually considered in the operation and maintenance of the systems used to operate the grid. For example, flagging inaccurate data and establishing a scan rate must be considered every time new data points are implemented.

If the Balancing Authority is not required to confirm the accuracy of their Frequency metering equipment at some reoccurring periodicity, it would eventually deteriorate and impact the accuracy of the Reporting ACE.

Similarly, if there is not a requirement to confirm availability of the system calculating Reporting ACE, there is no consequence for not maintaining such systems.

b. Requirement R4: The 99.95% uptime is overly prescriptive and there does not exist any technical justification. Unless supported by technical justification, this requirement should be removed. Further addition, the 0.001 Hz "accuracy" requirement is misleading. We suggest to replace "accuracy" with "resolution" to more properly convey the requirement.

The SDT believes “accuracy” and “resolution” conveys the same intent, however, the responses received did not support changing the term.

With respect to justification, the SDT utilized the same values currently within the existing BAL-005 standard and the base value the industry utilized when listing specifications for EMS.

c. Requirement R5: We agree with the need to provide operating personnel with accurate information that supports awareness and calculation of Reportable ACE, but the examples listed places emphasis on the secondary information as it fails to capture the more important pieces of information which were listed in the existing BAL-005. We therefore suggest R5 be revised to:

R5. The Balancing Authority shall make available to the operator information associated

with Reporting ACE including, but not limited to, real-time values for ACE, Interconnection

frequency, Net Actual Interchange with each Adjacent Balancing Authority Area and quality flags indicating missing or invalid data.

The SDT believes such information is necessary for the operator to know at all times if its Reporting ACE is accurate and the reason for why it may not be accurate, since the operator is utilizing Reporting ACE to balance Demand and resources at all times to ensure a reliable Interconnection.

d. R6: As with our comments on R4, the 99.5% uptime is overly prescriptive and restrictive, and there does not exist any technical justification. A 99.5% uptime requirement means that all model builds and software glitches couldn't exceed 43.8 hours in any given year. This is overly restrictive. Unless supported by technical justification, this requirement should be removed.

With respect to justification, the SDT utilized the same values currently within the existing BAL-005 standard and the base value the industry utilized when listing specifications for EMS.

e. R7: This requirement is not needed. R1 already stipulates the need to calculate and hourly megawatt-hour values (and Reporting ACE, as we suggested above); and R4 already stipulates the scan rate. Failure to meet either requirement will result in a BA being unable to comply with the standard in which case the BA must develop corrective actions to return to compliance. Having an explicit operating process to identify and mitigate errors affecting the scan-rate accuracy of data used in the calculation of Reporting ACE is redundant to the combined requirements in R1 and R4. We therefore suggest to remove R7.

The SDT has combined R1 and R8 to help understand the requirements. In addition, the SDT has provided a detailed rational for the requirements including R7 "the Operating Process". The Drafting Team agrees that in the absence of significant meter error, R1 and R4 allows for accurate control of the grid. Unfortunately, if a significant meter error exists and goes unaddressed, there can be significant impact to the controlling of the grid during the operating hour not captured in Reporting ACE that is then absolved through the accounting process of reconciling Actual Net Interchange. In the absence of a requirement such as R7, there is no impetus for an entity to correct the meter error in a timely manner to resolve the problem.

If for whatever reasons R7 is retained, then the term "Operating Process" should not be capitalized since it is not a NERC defined term.

The Operating Process has been defined by NERC as, '' A document that identifies general steps for achieving a generic operating goal. An Operating Process includes steps with options that may be selected depending upon Real-time conditions. A guideline for controlling high voltage is an example of an Operating Process."

f. R8: This requirement is implied in and redundant with, R1. Suggest to remove it.

The SDT has re-written and combined R1 and R8 as the new proposed R7 and has provided clarifying rationale.

Response:

Emily Rousseau - MRO - 1,2,3,4,5,6 – MRO

Group Name: MRO-NERC Standards Review Forum (NSRF)

Group Member Name	Entity	Region	Segments
Joe Depoorter	Madison Gas & Electric	MRO	3,4,5,6
Amy Casucelli	Xcel Energy	MRO	1,3,5,6
Chuck Lawrence	American Transmission Company	MRO	1
Chuck Wicklund	Otter Tail Power Company	MRO	1,3,5
Theresa Allard	Minnkota Power Cooperative, Inc	MRO	1,3,5,6
Dave Rudolph	Basin Electric Power Cooperative	MRO	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5,6
Jodi Jenson	Western Area Power Administration	MRO	1,6
Larry Heckert	Alliant Energy	MRO	4
Mahmood Safi	Omaha Public Utility District	MRO	1,3,5,6
Shannon Weaver	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Brad Perrett	Minnesota Power	MRO	1,5

Scott Nickels	Rochester Public Utilities	MRO	4
Terry Harbour	MidAmerican Energy Company	MRO	1,3,5,6
Tom Breene	Wisconsin Public Service Corporation	MRO	3,4,5,6
Tony Eddleman	Nebraska Public Power District	MRO	1,3,5

Answer Comment:

See attachment with Strikethrough

The proposed R1 should be shortened and merged with R7. There need not be mention of "mutually agreed upon" nor "time sychnronized". AGC and ACE use real-time values, not hourly values.

The SDT has re-written and combined R1 and R8 as the new proposed R7 and has provided clarifying rationale.

There is a reliability need for a "mutually agreed upon" source of the data. Otherwise Adjacent Balancing Authorities cannot expect to control to the same values if the source of those values has not been confirmed to be common. The confirmation may only need to occur once or upon modification. But it impacts the reliability of the data being provided.

BAL-005-1

R1. Each Balancing Authority shall *ensure* **that have a process to operate to common, accurate** *each* **Tie-Lines, Pseudo-Ties, and Dynamic Schedules with its** *an* **Adjacent Balancing Authorities**. *is equipped with a mutually* *agreed upon time synchronized common source to determine hourly megawatt-hour values*

The measure of this requirement is not logs or voice recordings. NSI is already checked with Inadvertent Accounting and the INT standards. The process that was proposed in R7 could be the validation and measure for R1

If the change to R1 above is made, R7 is no longer necessary.

R8 is redundant with when compared to the suggested wording above for BAL-005-1 R1 and BAL-006 R3.

The SDT has re-written and combined the old R1 and old R8 into a new proposed R7 and thus a new measure has been created. However, the Operating Process (new proposed R6) should contain all of the information used to identify and mitigate errors.

The scan-rate accuracy of Reporting ACE is critical to the effectiveness of Tie Line Bias Control and the accuracy of the performance measures based on Reporting ACE, i.e. CPS1, BAAL, DCS, and FRM. The hourly MWhs telemetered to each EMS from the tie line meters and agreed to by the Adjacent BAAs is required to be available and may be in the Operating Process to identify and mitigate errors affecting the accuracy of scan-rate data used in the calculation of Reporting ACE for each Balancing Authority Area. These errors are usually between integrated hourly scan-rate data and hourly accumulated meter data but can also occur as differences between the accumulated meter data of two adjacent BAAs.

Unfortunately, scan-rate values cannot be directly compared with each other because of differences between scan times and differences in scan-rates between

BAAs. This Operating Process could include analysis of two different data comparisons for each Adjacent BAA for each tie line. These data comparisons are:

1. The comparison of scan-rate data integrated over each hour with the MWh accumulated values telemetered separately for each tie line each hour for the first BAA.
2. The comparison of the MWh accumulated values telemetered separately with the MWh values agreed upon by the two adjacent BAAs.

If errors resulting from one of these data comparisons is excluded from the error identification and mitigation process, the errors excluded will be also be excluded from the performance measurements and responsibility for managing these excluded errors will be passed to the interconnection. This will result in frequency control error managed by all BAAs through the frequency bias terms of their Reporting ACE.

Response:

Terry BIlke - Midcontinent ISO, Inc. - 2 -

Answer Comment:	The proposed R1 should be shortened and merged with R7. There need not be mention of “mutually agreed upon” nor “time sychnronized”. AGC and ACE use real-time values, not hourly values.

BAL-005-1

R1. Each Balancing Authority shall have a process to operate to common, accurate Tie-Lines, Pseudo-Ties, and Dynamic Schedules with its Adjacent Balancing Authorities.

The SDT appreciates the suggestion. Unfortunately, this proposed requirement language lacks specifics to what data (hourly versus instantaneous) is being exchanged.

The measure of this requirement should not be logs or voice recordings. NSI is already checked with Inadvertent Accounting and the INT standards. The process that was proposed in R7 could be the validation and measure for R1

If the change to R1 above is made, R7 is no longer necessary.

R8 is redundant with when compared to the suggested wording above for BAL-005-1 R1 and BAL-006 R3

Thank you for your comment. The SDT has re-written and combined the old R1 and old R8 into a new proposed R7 and thus a new measure has been created. However, the Operating Process (new proposed R6) should contain all of the information used to identify and mitigate errors.

The scan-rate accuracy of Reporting ACE is critical to the effectiveness of Tie Line Bias Control and the accuracy of the performance measures based on Reporting ACE, i.e. CPS1, BAAL, DCS, and FRM. The hourly MWhs telemetered to each EMS from the tie line meters and agreed to by the Adjacent BAAs is required to be available and may be in the Operating Process to identify and mitigate errors affecting the accuracy of scan-rate data used in the calculation of Reporting ACE for each Balancing Authority Area. These errors are usually between integrated hourly scan-rate data and hourly accumulated meter data but can also occur as differences between the accumulated meter data of two adjacent BAAs.

Unfortunately, scan-rate values cannot be directly compared with each other because of differences between scan times and differences in scan-rates between BAAs. This Operating Process could include analysis of two different data comparisons for each Adjacent BAA for each tie line. These data comparisons are:

1. The comparison of scan-rate data integrated over each hour with the MWh accumulated values telemetered separately for each tie line each hour for the first BAA.
2. The comparison of the MWh accumulated values telemetered separately with the MWh values agreed upon by the two adjacent BAAs.

If errors resulting from one of these data comparisons is excluded from the error identification and mitigation process, the errors excluded will be also be excluded from the performance measurements and responsibility for managing these excluded errors will be passed to the interconnection. This will result in frequency control error managed by all BAAs through the frequency bias terms of their Reporting ACE.

Response:

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Answer Comment:	The proposed R1 should be shortened and merged with R7. No mention of "mutually agreed upon" nor "time sychnronized" is necessary. AGC and ACE use real-time values, not hourly values. We suggest the following: BAL-005-1 R1. Each Balancing Authority shall have a process to operate to common, accurate Tie-Lines, Pseudo-Ties, and Dynamic Schedules with its Adjacent Balancing Authorities. The SDT appreciates the suggestion. Unfortunately, this proposed requirement language lacks specifics to what data (hourly versus instantaneous) is being exchanged. The measure of this requirement is not logs or voice recordings. NSI is already checked with Inadvertent Accounting and the INT standards. The process that was proposed in R7 could be the validation and measure for R1. R7 would not be necessary if the change to R1 above is made and R8 would be redundant with when compared to the suggested wording above for BAL-005-1 R1 and BAL-006 R3. Thank you for your comment. The SDT has re-written and combined the old R1 and old R8 into a new proposed R7 and thus a new measure has been created. However, the Operating Process (new proposed R6) should contain all of the information used to identify and mitigate errors.

The scan-rate accuracy of Reporting ACE is critical to the effectiveness of Tie Line Bias Control and the accuracy of the performance measures based on Reporting ACE, i.e. CPS1, BAAL, DCS, and FRM. The hourly MWhs telemetered to each EMS from the tie line meters and agreed to by the Adjacent BAAs is required to be available and may be in the Operating Process to identify and mitigate errors affecting the accuracy of scan-rate data used in the calculation of Reporting ACE for each Balancing Authority Area. These errors are usually between integrated hourly scan-rate data and hourly accumulated meter data but can also occur as differences between the accumulated meter data of two adjacent BAAs.

Unfortunately, scan-rate values cannot be directly compared with each other because of differences between scan times and differences in scan-rates between BAAs. This Operating Process could include analysis of two different data comparisons for each Adjacent BAA for each tie line. These data comparisons are:

1. The comparison of scan-rate data integrated over each hour with the MWh accumulated values telemetered separately for each tie line each hour for the first BAA.

2. The comparison of the MWh accumulated values telemetered separately with the MWh values agreed upon by the two adjacent BAAs.

If errors resulting from one of these data comparisons is excluded from the error identification and mitigation process, the errors excluded will be also be excluded from the performance measurements and responsibility for managing these excluded errors will be passed to the interconnection. This will result in frequency control error managed by all BAAs through the frequency bias terms of their Reporting ACE.

Response:

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable

Group Name: ACES Standards Collaborators

Group Member Name	Entity	Region	Segments
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Bill Hutchison	Southern Illinois Power Cooperative	SERC	1
Michael Brytowski	Great River Energy	MRO	1,3,5,6
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
John Shaver	Arizona Electric Power Cooperative, Inc.	WECC	4,5
John Shaver	Southwest Transmission Cooperative, Inc.	WECC	1
Ryan Strom	Buckeye Power, Inc.	RFC	4
Scott Brame	North Carolina Electric Membership Corporation	SERC	3,4,5

Bill Watson	Old Dominion Electric Cooperative	SERC	3,4

Answer Comment:

1. We believe Requirement R1 should focus on detection and correction of a problem rather than a guarantee that a common source is available. This would better align with a risk-based approach that NERC is mandating during standard development. We believe this can be achieved by rephrasing the requirement to read
"Each Balancing Authority shall monitor mutually agreed-upon time-synchronized common source with Adjacent Balancing Authorities to determine hourly megawatt-hour values for each common Tie-Line, Pseudo-Tie, and Dynamic Schedule." We feel that by moving in this direction, the associated VSLs can be set to more adjustable criteria, such as the length of time between detection and correction, (e.g. under 30, 60, and 90 days).

The SDT has re-written and combined the old R1 and old R8 into a new proposed R7 and thus a new measure has been created. However, the Operating Process (new proposed R6) should contain all of the information used to identify and mitigate errors.

2. We feel the SDT should align the VSLs for R2 to more performance-based criteria. We agree that six-seconds is a reasonable benchmark, but question if it needs to be categorized as a severe VSL. Instead, we recommend assigning a sliding time scale to each VSL (e.g. greater than or equal to 6 seconds, and greater than or equal to 12 seconds, etc.)
Thank you for your comment. The SDT has modified the requirement to provide additional clarity.

2. In Requirement R3, the BA is expected to notify its RC within 45 minutes from the beginning of its inability to calculate Reporting ACE. If a BA encounters multiple instances when it is unable to calculate its Reporting ACE in a consecutive minute time period, but never haves an instance that is greater than thirty consecutive minutes, we want to confirm that the time period for notification begins with the first reportable instance. We believe this can be accomplished by replacing "an inability" with "the inability" at end of the requirement to read "…within 45 minutes of the beginning of the inability to calculate Reporting ACE."

Thank you for your comment. The SDT has modified the requirement to provide additional clarity.

4. We believe System Operators should be identified in Requirement R5, as this is a NERC-defined Glossary Term. Moreover, it does not provide any ambiguity for auditors and better aligns with those personnel identified to complete training for reliability-related tasks in Reliability Standard PER-005-2.

The SDT thanks you for your comment. However, the SDT believes that the term System Operator is too broad and may not address the correct personnel. By using the term operator, the BA will assure the information is provided to the correct personnel.

5. For Requirement R5, we agree with the SDT's approach that Reporting ACE can be a primary metric to determine operating actions or instructions. Furthermore, System Operators should be aware of when such metrics are based on poor or insufficient data. However, we disagree with the SDT's approach taken in the wording of this requirement. Proof of the existence of a graphical display or dated alarm

log, as mentioned as possible evidence for compliance, will only lead to confusion on how evidence should be presented. We believe rewording this requirement to "each Balancing Authority shall monitor the quality of information used to calculate its own Reporting ACE" achieves the intent of "making available" sufficient data to System Operators.

The Drafting Team disagrees that language to direct the "monitoring" of data will result in invalid data being brought to the attention of an operator. Effective monitoring can only occur if one knows what represents invalid data, provided in this instance by the flagging. The purpose of the measurement is to demonstrate that if adequate flagging of invalid data exists, it would likely appear on an alarm log or graphical display.

6. We feel the SDT should provide rationale on the need for Requirement R6. While we agree that "Reporting ACE is an essential measurement of the BA's contribution to the reliability of the Interconnection," we believe a requirement measuring the availability of a Reporting ACE calculation system is unnecessary. System Operators, when in distress, likely will rely on frequency meter measurements and communications with other Adjacent BAs when Reporting ACE is not available. This proposed standard already has an availability requirement listed in Requirement R4, and with a requirement that has a higher availability rate. We believe requiring a system be available should be reserved for the ERO Event Analysis Process, much like SCADA is for RCs and TOPs.

Reporting ACE is an essential measurement of the BA's contribution to the reliability of the Interconnection. Since Reporting ACE is a measure of the BA's reliability performance for BAL-001, and BAL-002, it is critical that Reporting ACE be sufficiently available to assure reliability.

7. We believe the VSLs criteria for Requirement R7 could be more performance-based, particularly with how fast the BA took to mitigate errors affecting the scan-rate accuracy of data. We recommend sliding scale criteria, such as within 15 minutes, within 30 minutes, etc.

Unfortunately since the resolution of each meter error situation is unique depending on the size of the error, the criticality of the meter, the equipment availability, and meter location, the Drafting Team could not use timing as determinant. Since having a process is a true or false condition, it left only one VSL level.

8. In Requirement R8, we believe the requirement should focus on detection and correction to better align with a risk-based approach. We believe this can be achieved by rephrasing the requirement to read "Each Balancing Authority shall use a common source for Tie-Lines, Pseudo-Ties, and Dynamic Schedules with Adjacent Balancing Authorities when calculating Reporting ACE." We feel that by moving the requirement in this direction, the associated VSLs can be set to adjustable criteria, such as the length of time between detection and correction, i.e. under 15 minutes, under 30 minutes, etc.

The SDT has re-written and combined the old R1 and old R8 into a new proposed R7 and thus a new measure has been created. However, the Operating Process (new proposed R6) should contain all of the information used to identify and mitigate errors.

9. The data retention of the proposed standard, current year plus three years, is significantly larger than the one year retention found in the current standard and goes beyond the three-year audit cycle for BAs. In

the context of a Risk-Based CMEP, we feel an entity should only need to retain one year's worth of data. There is minimal reliability benefit to requiring an entity to store data for longer than one year, especially considering the tools in place for the ERO to spot check or self-certify compliance activities more frequently than an audit.

The current effective version of BAL-003-1 requires Balancing Authorities to retain current year, plus three calendar years of Reporting ACE data.

10. We believe the Implementation Plan should be updated to account for the retirement of IRO-005-3.1a, as Requirement R1.6 of that standard has the RC monitoring ACE and not Reportable ACE for all its BAs.

The RC specifies the information to be supplied by the BAs.

11. The third bullet of the proposed definition for Automatic Time Error Correction, as listed within the Implementation Plan, has a typographical error and should reference ε10.

Thank you. We will make that correction.

Response:

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Answer Comment:

1. As stated in the answer to Question 1, Texas RE is concerned the SDT has not considered interconnections with a single BA. The initial SAR comments included the following statement: “Within the Purpose statement or Applicability section, the PRT also recommends that the SDT consider addressing the Hydro Quebec exception for tie line bias control in some form, or a single-BA exception.“ It does not appear the SDT addressed the single-BA issue which results in the Reliability Standard not being applicable to the ERCOT and Quebec Interconnections. This, in turn, affects BAL-001 applicability. If Reporting ACE is not applicable to interconnections with a single BA, BAL-001 might not apply to the ERCOT and Quebec Interconnections. Additionally, any BA that connects with the ERCOT Interconnection BA will not be able to accurately determine Reporting ACE which could cause failure of BAL-001 for those BAs (assuming they utilize net interchange values in their Reporting ACE). This omission creates a reliability gap. Texas RE recommends including Interconnections with a single BA.

   Reporting ACE has been redefined to require that all DC asynchronous tie lines with other interconnections be represented as Source-Sink pairs and excluded from Reporting ACE. The drafting team did this to insure that errors resulting from ties to other interconnections would not affect the quality of Tie Line Bias control. The contribution of DC flows from other interconnections is already included in the interconnection frequency, and therefore, there should be no adjustment for DC tie flows or DC schedules in Reporting ACE for single BA interconnections.

   Reporting ACE for a single BA interconnection is defined as:

   $RACE = (NI_A – NI_S) – 10B (F_A – F_S) + I_{ME}$

Since there are no tie lines another BA on the same interconnection, the first term, ($NI_A – NI_S$), becomes zero. Since there are no tie lines to another BA on the same interconnection, the third term also becomes zero. The leaves the Reporting ACE for the BA as:

$RACE = – 10B (F_A – F_S)$

This Reporting ACE is used in the CPS1 and BAAL requirements and must be calculated to determine compliance with those requirements although the actual value of Reporting ACE is not used because it is offset by other parts of the requirements. For example, in CPS1:

$CPS1 = \{2 – [(RACE / -10B) \times (F_A – F_S)]/\mathcal{E}_1^2\} \times 100 = \{2 - [(F_A – F_S)^2 / \mathcal{E}_1^2]\} \times 100$

Thus final compliance is not dependent upon the Frequency Bias Term. The same is true for BAAL.

2. There seems to be some inconsistency with regards to definitions. For example, the definition of "Reporting ACE" in the Standard is different than the NERC Glossary of Terms (Glossary) but there is no redline. The definition of "AGC" is different from the Glossary and there is a redline. Is intent of the SDT to change both terms in the Glossary? Frequency Bias Setting is not defined within this Standard so it appears there is no change to that term.

   It is the intent of the Drafting Team to add or modify all terms listed under the "New or Modified Terms" section.

3. Asynchronous Ties should be included in the derivation of ACE where applicable. Without it, Reporting ACE will be off by the magnitude

frequency applicable to the flows across a DC tie (especially if a trip of the DC occurs or an error in scheduling).

In the definition of Reporting ACE asynchronous DC ties between Interconnections are excluded from Reporting ACE and are handled as either a generator or load.

4.

Texas RE noticed the term "adjacent" is not capitalized in M1. Texas RE recommends removing "its" when describing "Adjacent Balancing Authority" as there could be more than one Adjacent Balancing Authority in M1.

The SDT has re-written and combined the old R1 and old R8 into a new proposed R7 and thus a new measure has been created.

To make R5 consistent with the Purpose statement, Texas RE recommends changing "operator" to System Operator to be clear on which "operator" the information shall be made available. This change should also take place in the VSL for R5.

The SDT thanks you for your comment. However, the SDT believes that the term System Operator is too broad and may not address the correct personnel. By using the term operator, the BA will assure the information is provided to the correct personnel.

5.

Per the comment in Question 1, R7 should be for all BAs not just BAs "within a multiple Balancing Authority Interconnection". R7 should only be relevant to the area of the Balancing Authority that is

	implementing an Operating Process. The intent of the requirement is applicable only to BAAs operating in a multiple BAA Interconnection. 6. Texas RE noticed the VSL for R1 does not include language should include language for each Tie Line, Pseudo-Tie or Dynamic Schedule to *be equipped* with an agreed upon source to determine values. As is, the VSL ignores the "equipped" language within the Standard. The key elements of the requirement are the *agreement* of a *source providing hourly values*, which are addressed in the VSL. The Drafting Team does not believe the VSL language is unclear not having restated the word "equipped". 7. Texas RE noticed the VSL language for R3 does not include "for 30 consecutive minutes". Should there be a dash in "30-consecutive" in Requirement 3? Thank you for your comment. The SDT has modified the standard to address your concerns. 8. Texas RE recommends changing the verbiage from "each calendar year" to "annually" or for "each rolling 12 month period". Specifically, R4 and R6 include the term "calendar year" which implies Jan 1 to Dec 31. Therefore, if a CEA evaluates compliance to the Requirement in mid-year, there cannot be an assertion of compliance for the current year. Consequently, if the CEA returns in two years, the half year's period of data should be available to ascertain compliance (per the

Evidence Retention statements. Texas RE would like the SDT consider whether this violates the RoP Appendix 4C Section 3.1.4.2 **Period Covered** "The audit period will not begin prior to the End Date of the previous Compliance Audit."? Morever, does it cause a gap in compliance monitoring (and reflect a possible gap in reliability)?

Since an Audit Period will include at least one entire calendar year, the Drafting Team feels "calendar year" is a sufficient timeframe. Data Retention requirements in a standard can and often do differ from the Audit Period. This is for various reasons, often involving the magnitude of data that may need to be retained.

Response:

David Jendras - Ameren - Ameren Services - 3 -

Answer Comment: **Ameren supports MISO's comments for this question**

Response:

Carol Chinn - Florida Municipal Power Agency - 4 -

Group Name: FMPA

Group Member Name	Entity	Region	Segments
Tim Beyrle	City of New Smyrna Beach	FRCC	4
Jim Howard	Lakeland Electric	FRCC	3
Greg Woessner	Kissimmee Utility Authority	FRCC	3
Lynne Mila	City of Clewiston	FRCC	3
Javier Cisneros	Fort Pierce Utility Authority	FRCC	4
Randy Hahn	Ocala Utility Services	FRCC	3
Don Cuevas	Beaches Energy Services	FRCC	1
Stan Rzad	Keys Energy Services	FRCC	4
Matt Culverhouse	City of Bartow	FRCC	3
Tom Reedy	Florida Municipal Power Pool	FRCC	6
Steven Lancaster	Beaches Energy Services	FRCC	3
Mike Blough	Kissimmee Utility Authority	FRCC	5
Mark Brown	City of Winter Park	FRCC	3
Mace Hunter	Lakeland Electric	FRCC	3

Answer Comment:	FMPA disagrees with the use of the term “accuracy” in R4.2. We believe the intent would be better described by the term “precision”, or perhaps “degree of accuracy”. The SDT believes “accuracy” and “precision” conveys the same intent, however, the responses received did not support changing the term. FMPA does not find any technical justification for the 99.5% availability requirement in R6, and believes it may be duplicative with BAL-001 and present a double jeopardy issue. With respect to justification, the SDT utilized the same values currently within the existing BAL-005 standard and the base value the industry utilized when listing specifications for EMS. The availability of Reporting ACE is not duplicative of the requirements in BAL-001. BAL-001 requires a certain level of performance. That performance is calculated based on valid data. Any invalid data, such as unavailable Reporting ACE is to be excluded in its measurement. Therefore no double jeopardy exists.
Response:	

Mark Holman - PJM Interconnection, L.L.C. - 2 -

Answer Comment:

Proposed Standard:
Located in BAL-005-1 R1:
R1. Each Balancing Authority shall ensure that each Tie-Line, Pseudo-Tie, and Dynamic Schedule with an Adjacent Balancing Authority is equipped with a mutually agreed- upon time synchronized common source to determine hourly megawatt-hour values.
1.1. These values shall be exchanged between Adjacent Balancing Authorities.

The phrase “Tie-Line” is not listed in the NERC Glossary, but instead “Tie Line” is listed.
Definition:
o Tie Line:
• A circuit connecting two Balancing Authority Areas.

Thank you. That correction will be made.

The definition of “Pseudo-Tie” should be updated to include Reporting ACE if that is the purpose of the BAL-005-1 R1.
Definition:
o Pseudo-Tie:
• A time-varying energy transfer that is updated in Real-time and included in the Actual Net Interchange term (NIA) in the same manner as a Tie Line in the affected Balancing Authorities’ control ACE equations (or alternate control processes).

Thank you. We will update the definition to reference Reporting ACE.

If the SDT chooses not to change the language for R1, the language in R1.1

should be modified. With the current langauge the purpose of R1.1 is to exchange the hourly megawatt-hour values with the appropriate Balancing Authority to determine billing and Inadvertent Interchange. This should be stated more clearly as the current requirement has it written that the values are shared with [any] Adjacent Balancing Authority.

PJM proposes the following R1.1:
1.1. These values shall be exchanged for each Tie Line, Pseudo-Tie, and Dynamic Schedule shared between affected Balancing Authorities.

The SDTs intent with the old Requirement R1 is to ensure that the information is available to the BAs for use in the calculation of Reporting ACE. The SDT has re-written and combined the old R1 and old R8 into a new proposed R7 and thus a new measure has been created. However, the Operating Process (new proposed R6) should contain all of the information used to identify and mitigate errors.

Response:

Chantal Mazza - Hydro-Qu?bec TransEnergie - 2 - NPCC

Answer Comment:

• In the Mapping Document for BAL-005-1, R9, there appears to be a contradiction in the Description and Change Justification section about the HVDC links and their inclusion or not in Reporting ACE calculation vs the definitions of Scheduled and Actual Net Interchanges that exclude asynchronous DC tie-lines directly connected to another interconnection.

• R1 vs R8: HQ faila to see the difference between the 2 requirements. Perhaps the Rationales should be enhanced for a better understanding.

• M1 and M8 do not seem appropriate measures for an agreement on common metering or other sources. HQ suggesst favoring a written agreement rather than operator logs or voice recordings.

The SDT has re-written and combined the old R1 and old R8 into a new proposed R7 and thus a new measure has been created. However, the Operating Process (new proposed R6) should contain all of the information used to identify and mitigate errors.

• Even though HQ agrees that balancing authorities should use common metering equipment, we feel that R1 does not belong in BAL-005. This requirement relates to energy measurements that are used for accounting purposes and that do not come into play in reporting ACE calculation. This requirement should remain in BAL-006 and does not affect in any way automatic generation control. R8 does address perfectly the common metering needs between balancing authorities for real-time control.

The scan-rate accuracy of Reporting ACE is critical to the effectiveness of Tie Line Bias Control and the accuracy of the performance measures based on Reporting ACE, i.e. CPS1, BAAL, DCS, and FRM. The hourly MWhs telemetered to each EMS from the tie line meters and agreed to by the Adjacent BAAs is required to be available and may be in the Operating Process to identify and mitigate errors affecting the accuracy of scan-rate data used in the calculation of Reporting ACE for each Balancing Authority Area. These errors are usually between integrated hourly scan-rate data and hourly accumulated meter data but can also occur as differences between the accumulated meter data of two adjacent BAAs.

Unfortunately, scan-rate values cannot be directly compared with each other because of differences between scan times and differences in scan-rates between BAAs. This Operating Process could include analysis of two different data comparisons for each Adjacent BAA for each tie line. These data comparisons are:

1. The comparison of scan-rate data integrated over each hour with the MWh accumulated values telemetered separately for each tie line each hour for the first BAA.
2. The comparison of the MWh accumulated values telemetered separately with the MWh values agreed upon by the two adjacent BAAs.

If errors resulting from one of these data comparisons is excluded from the error identification and mitigation process, the errors excluded will be also be excluded from the performance measurements and responsibility for managing these excluded errors will be passed to the interconnection. This will result in frequency control error managed by all BAAs through the frequency bias terms of their Reporting ACE.

Response:

Theresa Rakowsky - Puget Sound Energy, Inc. - 1 -

Answer Comment:

For BAL-005, R8, “MW Flow Values” should be specifically mentioned in R8 and not just in the R8 Rationale.

The SDT has re-written and combined the old R1 and old R8 into a new proposed R7 and thus a new measure has been created. However, the Operating Process (new proposed R6) should contain all of the information used to identify and mitigate errors.

Response:

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Group Name: Duke Energy

Group Member Name	Entity	Region	Segments
Doug Hils	Duke Energy	RFC	1
Lee Schuster	Duke Energy	FRCC	3
Dale Goodwine	Duke Energy	SERC	5

Greg Cecil	Duke Energy	RFC	6

Answer Comment:

General comment: Duke Energy recommends the drafting team consider moving the proposed R8 to R2. We feel that based on the common subject matter of both of these requirements, that it would be more appropriate to have them consecutively listed within a standard.

The SDT has re-written and combined the old R1 and old R8 into a new proposed R7 and thus a new measure has been created. However, the Operating Process (new proposed R6) should contain all of the information used to identify and mitigate errors.

R4: Duke Energy requests further clarification regarding on how an entity may demonstrate compliance with R4.2 specifically. Also, more background information regarding where the 0.001Hz number came from and what it is measure against would add to clarity of the standard. Perhaps an Operating Guideline that provides guidance or examples on how an entity may demonstrate compliance, as well as a background on the 0.001Hz number.

Calibration testing can be performed and results provided as evidence. The measurement is taken directly from the existing R17 of BAL-005-0.2b. The SDT will present your suggestion to the NERC OC for consideration.

R5: We request further clarification on the use of the term operator in R5. Is this in reference to a System Operator, if so, we recommend stating so in the standard. As written, it appears that the standard is in conflict with the rationale for R5 which uses the term System operator.

	The SDT thanks you for your comment. However, the SDT believes that the term System Operator is too broad and may not address the correct personnel. By using the term operator, the BA will assure the information is provided to the correct personnel.
Response:	
Andrea Basinski - Puget Sound Energy, Inc. - 3 -	
Answer Comment:	As worded, we do not believe that BAL-005-0.2b Requirement R1 is appropriate for FAC-001-3. Since FAC-001-3 applies to documented Facility interconnection requirements, it would be more appropriate to require that the documented interconnection requirements contain language stating that transmission, generation and end-user interconnected Facilities must be located within the Balancing Authority Area's metered boundaries. This could be accomplished by adding R3.3 stating "Procedures for ensuring that transmission Facilities, generation Facilities and end-user Facilities are within the Balancing Authority Area's metered boundaries." The requirement to verify that existing facilities are located with the metered boundaries of a Balancing Authority Area is most appropriately assigned to the TOP, and not to the TO, GO and the LSE. If a Transmission Owner was required to state in their Interconnection requirements that transmission, generation, and load must be within the metered boundary of a BAA, it would put the onerous on the Transmission

Owner to enforce it. The reliability concern of these elements not being within a BAA is a NERC reliability concern and must be enforceable by NERC. It is not appropriate for a TOP to be responsible to arrange for the Balancing Authority arrangements for load, generation, and transmission facilities that they may not own. They have neither the authority nor obligation. That is why the applicability is placed on the owners and not the operators**.** The LSE has been removed from the standard based on the RBR initiative.

Response:

Douglas Webb - Douglas Webb On Behalf of: Chris Bridges, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1
Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1
James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1
Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1

Answer Comment: KCP&L incorporates by reference its response to Survey Question No. 2.

Response:

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Group Name: NPCC--Project 2010-14.2.1 Phase 2 of Bal Auth Rel-based Controls - BAL-005-1, BAL-006-3, FAC-001-3

Group Member Name	Entity	Region	Segments
Alan Adamson	New York State Reliability Council, LLC	NPCC	10
David Burke	Orange and Rockland Utilities Inc.	NPCC	3
Greg Campoli	New York Independent System Operator	NPCC	2
Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
Mark Kenny	Northeast Utilities	NPCC	1
Helen Lainis	Independent Electricity System Operator	NPCC	2
Rob Vance	New Brunswick Power Corporation	NPCC	9
Paul Malozewski	Hydro One Networks Inc.	NPCC	1
Bruce Metruck	New York Power Authority	NPCC	6
Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
Brian Robinson	Utility Services	NPCC	8
Wayne Sipperly	New York Power Authority	NPCC	5

Edward Bedder	Orange and Rockland Utilities Inc.	NPCC	1
Michael Jones	National Grid	NPCC	1
Brian Shanahan	National Grid	NPCC	1
Glen Smith	Entergy Services, Inc.	NPCC	5
RuiDa Shu	Northeast Power Coordinating Council	NPCC	10
Connie Lowe	Dominion Resources Services, Inc.	NPCC	5
Guy Zito	Northeast Power Coordinating Council	NPCC	10
Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
Robert Pellegrini	The United Illuminating Company	NPCC	1
Kathleen Goodman	ISO - New England	NPCC	2

Answer Comment:

In the Automatic Generation Control (AGC) definition consider removing "Automatically adjusts" and replace it with "determines". The BA does not always have the capability of making an automatic adjustment. For example, a BA can send a requested loading value down through the RIG (Remote Intelligent Gateway) and have the local GO/GOP or DP/LSE with smaller units to meet the load, but do not have direct control over the units. It's the local GO/GOP or DP/LSE who owns and/or operates the units that actually execute changes in loading.

The SDT has modified the definition to address your concern. The LSE has been removed from the standard based on the RBR initiative.

Requirement R1

The use of the following text needs to be reconsidered:

… each Tie-Line, Pseudo-Tie, and Dynamic Schedule with an Adjacent BA…

… time-synchronized common source…

… to determine hourly megawatt-hour values

Pseudo-ties and Dynamic Schedules are not tie lines; they are output values from resources. In some cases these output values can be used directly, but in other cases the values are adjusted by the EMS to represent the proportion of the output to be incorporated into the BAs ACE.

The Drafting Teams is not certain if there is a question or comment being stated here.

The phrase "time-synchronized common source" requires explanation. If two BAs are using a common source for real time flows, then by definition the values are synchronized. If, on the other hand, R1 only applies to Hourly (Billing) values the phrase is still superfluous. However, if the phrase is meant to mandate that all inter-tie meters be synchronized to a common time, then that needs to be explained more clearly.

The scan-rate accuracy of Reporting ACE is critical to the effectiveness of Tie Line Bias

Control and the accuracy of the performance measures based on Reporting ACE, i.e. CPS1, BAAL, DCS, and FRM. The hourly MWhs telemetered to each EMS from the tie line meters and agreed to by the Adjacent BAAs is required to be available and may be in the Operating Process to identify and mitigate errors affecting the accuracy of scan-rate data used in the calculation of Reporting ACE for each Balancing Authority Area. These errors are usually between integrated hourly scan-rate data and hourly accumulated meter data but can also occur as differences between the accumulated meter data of two adjacent BAAs.

Unfortunately, scan-rate values cannot be directly compared with each other because of differences between scan times and differences in scan-rates between BAAs. This Operating Process could include analysis of two different data comparisons for each Adjacent BAA for each tie line. These data comparisons are:

1. The comparison of scan-rate data integrated over each hour with the MWh accumulated values telemetered separately for each tie line each hour for the first BAA.
2. The comparison of the MWh accumulated values telemetered separately with the MWh values agreed upon by the two adjacent BAAs.

If errors resulting from one of these data comparisons is excluded from the error identification and mitigation process, the errors excluded will be also be excluded from the performance measurements and responsibility for managing these excluded errors will be passed to the interconnection. This will result in frequency control error managed by all BAAs through the frequency bias terms of their Reporting ACE.

Agree that Real-time metering of interties requires the use of common sources to both BAs (as per Requirement 8). But given that R1 is focused on hourly megawatt-hour values, the requirement becomes a market/billing issue not a Real-time issue. R1 should be revised to clarify the intent.

The SDT has re-written and combined the old R1 and old R8 into a new proposed R7 and thus a new measure has been created. However, the Operating Process (new proposed R6) should contain all of the information used to identify and mitigate errors.

Suggest that the Real-time installation of meters be left to BA Certification.

The BA Certification process occurs one time. The installation or modification of meters occurs over a Balancing Authority's lifetime.

Requirement R2

What is meant by a 6 second sampling rate? Is that that the rate that a BA samples the data values it has at the moment, or does the 6 seconds represent a time delay between real-time and ACE calculations? This can be an issue for BAs that make use of multi-tier samples, where Owner X samples a group of resources every X-seconds, then sends that block of data to the BA who would sample all the blocks every Y-seconds.

Traditionally, sampling rates were associated with how well a continuous function can be recreated. A sampling rate that is slower that the fundamental oscillations in the continuous function will not be able to reproduce that original function (the issue of aliasing as experienced in watching a TV program in which a wheel appears to rotate in the wrong direction).

What is the reliability justification for this scan rate?

A critical component of the accuracy of Reporting ACE is the timeliness of the data sampled. Driving AGC using stale data would be counter-productive and could possibly create reliability problems. The requirement establishes a minimum threshold of how often the sampling must occur. Entities can chose to sample more often. As long as all data used to calculate Reporting ACE is sampled within six seconds, the source data should not introduce significant error.

Requirement R4

The value of monitoring system frequency is recognized, but again as suggested in our response to R1, the issue of frequency monitoring would seem to be better suited to a certification process rather than to a mandatory standard.

Balancing Authority Certification processes occur one time. The need for accurate frequency values consistently is an on-going real-time issue.

What is the justification for the values in Parts 4.1 and 4.2?

With respect to justification, the SDT utilized the same values currently within the existing BAL-005 standard and the base value the industry utilized when listing specifications for EMS.

Requirement R5

The value of alarming is recognized, but given the fact that R5 could be a federal law, the question could be asked:

- What constitutes “quality” as in quality flags?

• What constitutes “invalid” as in invalid data?

The concern addressed in R5 (alarming) would be better addressed in certification. The systems that are certified should have alarming processes built into them, customized to the needs of the BA.

Each meter is unique in its capability and values it provides. It is upon the Balancing Authority to determine what values would be invalid for their operator to receive from their meters and what indications can be provided as a quality flag.

Requirement R6

Real-time errors in the ACE components are reflected in various other parameters:

1. System Frequency

2. Time Error (even if TE is not a standard is still computed)

3. End of Day checkouts

4. End of Month billing

As written R6 is an exercise is data collection and manipulation.

R6 does not represent any data collection and manipulation. It establishes the minimum availability of the system used to calculate Reporting ACE. The inability to calculate Reporting ACE creates a reliability risk to the grid.

What are the implications of an unavailability less than 99.5%, and at what points are reliability impacted (and how)?

With respect to justification, the SDT utilized the same values currently within the existing BAL-005 standard and the base value the industry utilized when listing specifications for EMS. Reporting ACE is an essential measurement of the BA's contribution to the reliability of the Interconnection. Since Reporting ACE is a measure of the BA's reliability performance for BAL-001, and BAL-002, it is critical that Reporting ACE be sufficiently available to assure reliability.

Requirement R7

Requirement R7 requires clarification.

The process of monitoring for data errors and the process for mitigating errors that are identified are built into modern EMS systems.

The requirement as written focuses only on errors "affecting the scan-rate accuracy of data used in the calculation of Reporting ACE…". As written, this is not all data used in ACE. Moreover, data does not impact the accuracy of the rate of scanning. The rate of scanning is a built in function to the EMS / SCADA programs. The data (good or bad) is scanned regularly.

The SDT has re-written and combined the old R1 and old R8 into a new proposed R7 and thus a new measure has been created. However, the Operating Process (new proposed R6, as modified) should contain all of the information used to identify and mitigate errors.

As written R7 does not rise to the level of a NERC standard and should be deleted.

The Drafting Team believes the absence of a requirement to address persistent meter error will allow significant meter error to remain in the calculation and control of the grid, creating burden on others.

The intent of R1 should be to ensure that a common metering point be identified for all Real-time inter-BA tie lines. The issue of Pseudo-Ties and Dynamic Schedules is really a business agreement between the two BAs in cooperation with the resource being used, and therefore is not a standard matter.

The issue being addressed in R1 in relation to Pseudo-Ties and Dynamic Schedules is their inclusion in Reporting ACE. This is particularly true of allocated shares of generation resources or supplementary regulation. If they are not included in Reporting ACE, the values will not be consistent and accurate.

Requirement R8

The requirement is on Pseudo-ties and Dynamic Schedules, but Pseudo-Ties and Dynamic Schedules are not tie lines, they are output values from resources. In some cases these output values can be used directly, but in other cases the values are adjusted by the EMS to represent the proportion of the output to be incorporated into the BA's ACE.

The Drafting Team is not sure if you are raising a question or concern. As you state, these values are necessary to be included in Reporting ACE and must originate from common sources for both Balancing Authorities to control to the same values.

The requirement to utilize a common source for all interties is a valid requirement.

The agreements referred to in R8 are Interconnection Agreements and therefore not a matter for a NERC standard.

Interconnection agreements are between the element owner and the Transmission Owner to whom they are interconnecting. This agreement of common source of Reporting ACE data must occur between Adjacent Balancing Authorities, who are not parties to the Interconnection Agreement.

Response:

Albert DiCaprio - PJM Interconnection, L.L.C. - 2 - RFC

Group Name: ISO Standards Review Committee

Group Member Name	Entity	Region	Segments
Charles Yeung	SPP	SPP	2

Ben Li	IESO	NPCC	2
Mark Holman	PJM	RFC	2
Kathleen Goodman	ISONE	NPCC	2
Greg Campoli	NYISO	NPCC	2
Ali Miremadi	CAISO	WECC	2
Terry Bilke	MISO	RFC	2
Christina Bigelow	ERCOT	TRE	2

Answer Comment: **See file attached to Question 1 for the SRC comments on the rationale and language of several requirements.**

Response:

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Answer Comment: In general, BPA agrees with the current draft of BAL-005-1 but has some concerns with how BAs will meet the proposed R7 – relating to implementing an "Operating Process". BPA believes that R7 is poorly written and needs to be revisited.

Thank you for your comment. The SDT has made minor modifications to Requirement R7 reflecting other comments received, hopefully these modifications have provided the clarification necessary to address your concern.

Response:

Jason Smith - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool	SPP	2
Jason Smith	Southwest Power Pool	SPP	2
Ashley Stringer	Oklahoma Municipal Power Authority	SPP	4

Answer Comment: Identification of common sources of measurement (R8) and recording (R1) are BA certification items, not ongoing responsibilities that need to be checked periodically. New tie lines or “inputs” into the BA ACE calculations should be captured in FAC-001.

BA Certification occurs one time. New or modified tie-line values happen continually over the lifetime of a Balancing Authority. FAC-001 deals with Interconnection Requirements for Transmission Owners and Generator Owners. The need to have accurate Reporting ACE calculations is a real-time function that must occur to allow for adequate and accurate BAA control, as is the purpose of BAL-005.

There is continued confusion regarding the six second scan rate. A BA can demonstrate a scan rate of its received data every six seconds, but there is no requirement for the data "made available to" the BA to be scanned at a certain scan rate. To be more clear, the requirement should specify that "measurements should be made by the common source(s) and provided to the BA at least every six seconds for the calculation of Reporting ACE". At its worst, that should result in an ACE calculation being made and reported with data no longer than 12 seconds old.

Thank you for your comment. The SDT has modified the requirement to clarify our intent for this to be a design requirement and thus a capability requirement. Performance measurement associated with Reporting ACE is addressed in the other BAL standards.

The Rational for Requirement R3 leads with a sentence that has no basis in the Functional Model and should be deleted. The RC does not have responsibility "for coordinating the reliability of bulk electric systems for member BA's." The RC is responsible for "Mitigating energy and transmission emergencies" among other things. The statement made in the Rationale overstates the responsibility of the RC and minimizes the BA role. The BA has primary responsibility for maintaining load and generation balance and the RC has authority to step in and provide assistance if the BA is unable to maintain

	its obligations. Delete the first sentence of the Rationale for R3 box. What purpose does it serve to allow a BA an additional 15 minutes after 30 minutes of an inability to calculate ACE before notifying the RC. Delete “within 45 minutes of the beginning … ACE” and replace with “without delay”. As stated, the requirement would allow a BA to not calculate Reporting ACE for 44 minutes and then notify the RC. Or would require a BA that could not calculate Reporting ACE for 31 minutes but then was successful to also notify the RC. The intent of the change is not clear and seems to indicate a reduction in reliability. “Without delay” in and of itself is not a measureable timeframe. Previously there was no limit on when the notification had to occur. The fifteen minutes after is a reasonable timeframe and improvement over no time limit. What is the specific rationale for requirement of 99.95% (or 0.05% outage allowance = 43 seconds/day) uptime for frequency measurement? Is some reliability threshold crossed at 44 seconds of frequency measurement unavailability each day? Is the intent of R4.2 to still require calibration of the measurement or simply to utilize a provided significant digit of .001 Hz? The new R4 uses the term “accuracy” of .001Hz rather than the old R17 description of “<=0.001Hz”. Also the measurement M4 requires demonstration of “minimum accuracy” which lends itself to requiring a demonstrable calibration that is not specifically stated in R4. The intended statement in the mapping document for R17 to R4 is not captured well in the resulting R4. With respect to justification, the SDT utilized the same values currently within the existing BAL-005 standard and the base value the industry utilized when listing specifications for EMS. Reporting ACE is an essential measurement of the BA’s contribution to the reliability of the Interconnection. Since Reporting

ACE is a measure of the BA's reliability performance for BAL-001, and BAL-002, it is critical that Reporting ACE be sufficiently available to assure reliability.

Suggest deleting R5 and suggest this requirement be evaluated for inclusion in the Project 2009-02 Real-Time Monitoring and Analysis Capabilities work since it relates to identifying sources of inccorect input data. Any Operating Process or Procedure to identify, correct, or mitigate incorrect or lost input data out of Project 2009-02 should include ACE data. If kept, the Measure M5 includes an additional requirement that the suspect/garbage data indication should be indicated on BOTH the calculated Reporting ACE result as well as on the individual suspect/garbage data point. We suggest that R5 should include similar language to M5 if that is the intent. The RSAW should be adjusted based on changes to R5 or M5.

Thank you for your comment. The SDT believes that this requirement deals with flagging bad data used in the calculation of Reporting ACE.

Suggest deleting R6 as it is duplicative and in conflict with BAL-001-2. The reliability implication of "knowing" ACE is to be able to ensure balance is maintained. That is accomplished in CPS and BAAL and does not need to be duplicated here. The reporting % does not indicate a direct measurement of reliability and is administrative only.

BAL-001-2 measurements exclude values when Reporting ACE is not available. BAL-001-2 does not limit the unavailability of Reporting ACE. The SDT believes that R6 is necessary to provide reliable information to the BA which allows the BA to effectively control in order to balance Demand and resources at all time.

Suggest deleting R7 and suggest this requirement be evaluated for inclusion in the Project 2009-02 Real-Time Monitoring and Analysis Capabilities work since it relates to identifying sources of inccorect input data. Any Operating Process or Procedure to identify, correct, or mitigate incorrect or lost input data out of Project 2009-02 should include ACE data.

Thank you for your comment. The SDT believes that this requirement deals with flagging bad data used in the calculation of Reporting ACE.

Regarding R8: There is no demonstration of the reliability impact of using non-common meters between BA's for the purpose of Reporting ACE. In fact, in order to support reliability, the requirement should specify that redundant sources be made available to be used for Reporting ACE. Loss of the single, common source would result in lost input to the ACE calculation. A best practice that most BA's use is to identify a primary, common source for measurements and a secondary, common source for measurements and ensure each adjacent BA is using the same common source at the same time. *Common source measurements do not ensure accuracy, they just ensure the same error is introduced in both adjacent ACE calculations and therefore net each other out.*

The SDT agrees that a common source minimizes any error from impacting anyone other than the two Balancing Authorities it is between. The requirement does not disallow you from having more than one source for your meter data.

Response:

5. Please provide any issues you have on the proposed change to the BAL-006-3 standard and a proposed solution.

John Fontenot - Bryan Texas Utilities - 1 -

Answer Comment:	none

Leonard Kula - Independent Electricity System Operator - 2 -

Answer Comment:

We do not see the need to retain any of the BAL-006 requirements in a NERC Reliability Standard. Standard. Inadvertent Interchange is calculated for reconciliation purpose and as such, does not have any reliability value for real-time operations or post-mortem analysis. The facilities used for recording hourly Inadvertent Interchange are more suited to be stipulated in the BA's Organization Certification Requirements; the procedure to calculate, reconcile and resolve disputes over Intervertent Interchange can be put into operating guide or even in the NAESB's business practices.

Consistent with the risk-based principle, we suggest that unless there is clear demonstration that failure to calculate and reconcile Inadvertent Interchange can adversely affect operating reliability, this standard should be retired with its requirements transferred to other NERC and/or NAESB documents.

The SDT has surveyed the industry to determine the outcome of BAL-006. The majority of the industry has recommended retirement of BAL-006 with certain provisions being included in a non-reliability process. The SDT will submit documents to move this effort forward in the standards development process.

Response:

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Group Name: MRO-NERC Standards Review Forum (NSRF)

Group Member Name	Entity	Region	Segments
Joe Depoorter	Madison Gas & Electric	MRO	3,4,5,6
Amy Casucelli	Xcel Energy	MRO	1,3,5,6
Chuck Lawrence	American Transmission Company	MRO	1
Chuck Wicklund	Otter Tail Power Company	MRO	1,3,5
Theresa Allard	Minnkota Power Cooperative, Inc	MRO	1,3,5,6
Dave Rudolph	Basin Electric Power Cooperative	MRO	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5,6
Jodi Jenson	Western Area Power Administration	MRO	1,6
Larry Heckert	Alliant Energy	MRO	4
Mahmood Safi	Omaha Public Utility District	MRO	1,3,5,6
Shannon Weaver	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Brad Perrett	Minnesota Power	MRO	1,5
Scott Nickels	Rochester Public Utilities	MRO	4
Terry Harbour	MidAmerican Energy Company	MRO	1,3,5,6
Tom Breene	Wisconsin Public Service Corporation	MRO	3,4,5,6
Tony Eddleman	Nebraska Public Power District	MRO	1,3,5

Answer Comment: **R1 is embedded in R2 and R3 and therefore unnecessary.**

The sub-bullets of R3 should be bullets and not Requirements. Additionally, the end-of-day check should be an agreement of on and off peak totals, not hourly values. There are INT standards that require confirmation of hourly schedules.

In the compliance section, RROs do not fill out monthly summary reports and submit them to NERC.

The SDT has surveyed the industry to determine the outcome of BAL-006. The majority of the industry has recommended retirement of BAL-006 with certain provisions being included in a non-reliability process. The SDT will submit documents to move this effort forward in the standards development process.

Response:

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Answer Comment: The sub-requirements of R3 should be bullets, not sub requirements.

The end of day check should be an agreement of on and off peak totals, not hourly values. Confirmation of hourly schedules are already required in other standards.

The SDT has surveyed the industry to determine the outcome of BAL-006. The majority of the industry has recommended retirement of BAL-006 with certain provisions being included in a non-reliability process. The SDT will submit documents to move this effort forward in the standards development process.

Response:

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable

Group Name: ACES Standards Collaborators

Group Member Name	Entity	Region	Segments
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Bill Hutchison	Southern Illinois Power Cooperative	SERC	1
Michael Brytowski	Great River Energy	MRO	1,3,5,6
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
John Shaver	Arizona Electric Power Cooperative, Inc.	WECC	4,5
John Shaver	Southwest Transmission Cooperative, Inc.	WECC	1
Ryan Strom	Buckeye Power, Inc.	RFC	4
Scott Brame	North Carolina Electric Membership Corporation	SERC	3,4,5
Bill Watson	Old Dominion Electric Cooperative	SERC	3,4

Answer Comment: We appreciate the SDT’s efforts to remove Requirement R3 from this standard.

Response:

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Answer Comment:

In the revised language for BAL-006-3 R4, Texas RE recommends replacing the undefined term “Regional Reliability Organization Survey Contact” with Reliability Coordinator. This may be outside the purview of the SDT but consideration should be provided to clarify the responsibility while the Standard is being considered.

The SDT has surveyed the industry to determine the outcome of BAL-006. The majority of the industry has recommended retirement of BAL-006 with certain provisions being included in a non-reliability process. The SDT will submit documents to move this effort forward in the standards development process.

Response:

David Jendras - Ameren - Ameren Services - 3 -

Answer Comment:

Ameren supports MISO's comments for this question

Response:

Theresa Rakowsky - Puget Sound Energy, Inc. - 1 -

Answer Comment:

As stated in question #2 above, as worded, we do not believe these requirements are appropriate for FAC-001-3. Since FAC-001-3 applies to documented Facility interconnection requirements, it would be more appropriate to require that the documented interconnection requirements contain language stating that transmission, generation and end-user interconnected Facilities must be located within the Balancing Authority Area's metered boundaries. This could be accomplished by adding R3.3 stating "Procedures for ensuring that transmission Facilities, generation Facilities and end-user Facilities are within the Balancing Authority Area's metered boundaries." The requirement to verify that existing facilities are located with the metered boundaries of a Balancing Authority Area is most appropriately assigned to the TOP, and not to the TO, GO and the LSE. Please reference our response to your comment in the FAC-001 question.

Response:

Douglas Webb - Douglas Webb On Behalf of: Chris Bridges, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1
Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1
James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1
Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1

Answer Comment: KCP&L incorporates by reference its response to Survey Question No. 2.

Response:

Albert DiCaprio - PJM Interconnection, L.L.C. - 2 - RFC

Group Name: ISO Standards Review Committee

Group Member Name	Entity	Region	Segments
Charles Yeung	SPP	SPP	2

Ben Li	IESO	NPCC	2
Mark Holman	PJM	RFC	2
Kathleen Goodman	ISONE	NPCC	2
Greg Campoli	NYISO	NPCC	2
Ali Miremadi	CAISO	WECC	2
Terry Bilke	MISO	RFC	2
Christina Bigelow	ERCOT	TRE	2

Answer Comment: The SRC recommends that BAL-006 be retired.

The SDT has surveyed the industry to determine the outcome of BAL-006. The majority of the industry has recommended retirement of BAL-006 with certain provisions being included in a non-reliability process. The SDT will submit documents to move this effort forward in the standards development process.

See file attached to Question 1 for the full text of the comments to Question 5

Response:

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Answer Comment: None.

Jason Smith - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool	SPP	2
Jason Smith	Southwest Power Pool	SPP	2
Ashley Stringer	Oklahoma Municipal Power Authority	SPP	4

Answer Comment:

The purpose of BAL-006-2 (and resulting BAL-006-3) do not impact reliability. In fact, this enforceable Standard only serves to provide administrative metrics that are then used to facilitate either financial or in-kind reimbursements. In order to make this standard truly results based in relation to system reliability, requirements such as a BA shall not accumulate inadvertent interchange in excess of XX,XXX MWh per month would need to be created. No BA or RC will ever take reliability actions or issue Operating Instructions in relation to the accumulated or forecast accumulated inadvertent interchange. Resolution of inadvertent is an after-the fact reimbursement and not a reliability issue.

The SDT has surveyed the industry to determine the outcome of BAL-006. The majority of the industry has recommended retirement of BAL-006 with certain provisions being included in a non-reliability process. The SDT will submit documents to move this effort forward in the standards development process.

Response:

6. Please provide any issues you have on the proposed change to the FAC-001-3 standard and a proposed solution.

John Fontenot - Bryan Texas Utilities - 1 –

Answer Comment: none

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO

Answer Comment: In the "Table of Compliance Elements", the Violation Severity Levels, R5 and R6 should correctly refer to Transmission Owner and Generator Owner, respectively (instead of Transmission Operator and Generator Operator)

Thank you for your comment, the VSL has been corrected.

Response:

Louis Slade - Dominion - Dominion Resources, Inc. - 6 -

Group Name: Dominion

Group Member Name	Entity	Region	Segments
Randi Heise	NERC Compliance Policy	NPCC	5,6
Connie Lowe	NERC Compliance Policy	SERC	1,3,5,6
Louis Slade	NERC Compliance Policy	RFC	5,6
Chip Humphrey	Power Generation Compliance	SERC	5
Nancy Ashberry	Power Generation Compliance	RFC	5
Larry Nash	Electric Transmission Compliance	SERC	1,3
Candace L Marshall	Electric Transmission Compliance	SERC	1,3
Larry W Bateman	Transmission Compliance	SERC	1,3
Jeffrey N Bailey	Nuclear Compliance	SERC	5
Russell Deane	Nuclear Compliance	NPCC	5

Answer Comment: Dominion submitted comments - 2010-14_2_1_BARC-Unofficial_Comment_Form-20150715.docx

Response:

Jeri Freimuth - APS - Arizona Public Service Co. - 3 -

Answer Comment: APS agrees with moving these requirements from BAL-005 to the new FAC-001-3. APS also agrees with the proposed requirement language. APS does not agree that the measurements of these newly placed requirements have been correctly drafted.

A Transmission Operator, Generator Operator, or Load-Serving-Entity possessing the Facility interconnection requirements of the Transmission Owner they are attempting to interconnect with is not proof they are within a Balancing Authority Area. Evidence they are within a Balancing Authority Area would be demonstrated by possessing an executed Interconnection Agreement or similar contract. The measures will need to be corrected to reflect that. The RSAW will need to be corrected to line up with those changes.

The SDT agrees with you and has corrected the VSL and RSAW.

Response:

Leonard Kula - Independent Electricity System Operator - 2 -

Answer Comment: **We concur with the proposed revisions to FAC-001-3.**

Response:

Terry BIlke - Midcontinent ISO, Inc. - 2 -

Answer Comment: Do not change FAC-001 as this confuses the intent of the original requirement. There is virtually no way to prove that a particular component is within a BA. The original requirement was intended to be sure Control Areas balanced. This is done by operating to common ties and performing Inadvertent Interchange checkouts.

The original intent of the requirements in BAL-005 was to assure all Facilities within the interconnected network are accounted for within the boundaries of a BAA, which allows for the BA to balance Demand and resources. The SDT will suggest additional language changes to FAC-001-3 to help clarify the issues.

Response:

Chris Mattson - Tacoma Public Utilities (Tacoma, WA) - 5 -

Answer Comment:

1) FAC-001-3 R5 Severe VSL should state "The Transmission Owner……" to match R5 which places responsibility for the requirement on the Transmission Owner. Currently the VSL states the Transmission Operator will comply.

2) FAC-001-3 R6 Severe VSL should state "The Generator Owner……" to match R6 which places responsibility for the requirement on the Generator Owner. Currently the VSL states the Generation Operator will comply.
Thank you for your comments, the SDT agrees with you and has corrected the VSL and RSAW.

Response:

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert Schaffeld	Southern Company Services, Inc	SERC	1

John Ciza	Southern Company Generation and Energy Marketing	SERC	6
R Scott Moore	Alabama Power Company	SERC	3
William Shultz	Southern Company Generation	SERC	5

Answer Comment:

Should the SDT disagree that existing processes are adequate to accomplish the desired outcome (as described in the comments to Question #2), then the following is recommended:

1. Remove the inseration of 4.1.3 and R5-R7.
2. Modify R3.2 to read “Procedures for notifying the BA, TOP and RC of new or materially modified existing interconnections.”
3. Modify R4.2 to read “Procedures for notifying the BA, TOP and RC of new interconnections.”

Additionally, if possible, it is recommended that there be continued coordination with the FAC-001 team that produced FAC-001-2 in 2014 before any changes to FAC-001-2 are made.

The SDT has re-written and combined the old R1 and old R8 into a new proposed R7 and thus a new measure has been created. However, the Operating Process (new proposed R6) should contain all of the information used to identify and mitigate errors.

The NERC staff assigned to this SDT is in continuous contact with the other SDTs.

Eleanor Ewry - Puget Sound Energy, Inc. - 1,3,5 - WECC

Answer Comment:

As stated in question #2 above, as worded, we do not believe these requirements are appropriate for FAC-001-3. Since FAC-001-3 applies to documented Facility interconnection requirements, it would be more appropriate to require that the documented interconnection requirements contain language stating that transmission, generation and end-user interconnected Facilities must be located within the Balancing Authority Area's metered boundaries. This could be accomplished by adding R3.3 stating "Procedures for ensuring that transmission Facilities, generation Facilities and end-user Facilities are within the Balancing Authority Area's metered boundaries." The requirement to verify that existing facilities are located with the metered boundaries of a Balancing Authority Area is most appropriately assigned to the TOP, and not to the TO, GO and the LSE.
The SDT has modified FAC-001-3 to clarify the issues. The LSE has been removed from the standard based on the RBR initiative.

Response:

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable

Group Name: ACES Standards Collaborators

Group Member Name	Entity	Region	Segments
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3

Bill Hutchison	Southern Illinois Power Cooperative	SERC	1
Michael Brytowski	Great River Energy	MRO	1,3,5,6
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
John Shaver	Arizona Electric Power Cooperative, Inc.	WECC	4,5
John Shaver	Southwest Transmission Cooperative, Inc.	WECC	1
Ryan Strom	Buckeye Power, Inc.	RFC	4
Scott Brame	North Carolina Electric Membership Corporation	SERC	3,4,5
Bill Watson	Old Dominion Electric Cooperative	SERC	3,4

Answer Comment:

We believe FAC-001-3 should not be modified based on the reasons previously provided in question #2. We recommend the SDT retire the requirements moved from BAL-005-0.2b based on the reasons cited. At a minimum, we recommend the SDT provide technical justification on why these requirements are necessary.

The SDT's intent is to assure all Facilities within the interconnect network are accounted for within the boundaries of a control area and strongly feels the requirements are necessary to allow the BA to balance Demand and resources. The SDT has modified FAC-001-3 to help clarify the issues.

Response:

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Answer Comment:	In R5, R6, and R7 it seems duplicitous to include, “metered boundaries” in the phrase “Balancing Authority Area’s metered boundaries” because the first sentence of Balancing Authority Area definition is “The collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority.” Texas RE noticed the Evidence Retention section does not address LSEs. Texas RE noticed the format of FAC-001-3 does not follow the new NERC Results Based Standards Template. Texas RE noticed the VSL for R5 refers to the “Transmission Operator” but the Requirement is applicable to the Transmission Owner. The VSL for R6 refers to the “Generator Operator” but the Requirement is applicable to the Generation Owner. The SDT agrees with your assertion that the use of “metered boundaries” may be duplicitous, however, the SDT believes the requirements are warranted. The information must be made available to all parties to assure balance of Demand and resources. The SDT believes that the requirement applies to all entities involved with generation or transmission. The LSE has been removed from the standard based on the RBR initiative. The SDT is aware of the formatting issue and will forward your comments regarding the format of FAC-001-3 to the NERC Standards Committee. The SDT agrees with your comment about the application to GO and has made the change as you suggested.

Response:

Bob Thomas - Illinois Municipal Electric Agency - 4 -

Answer Comment: Please see comment under Qustion 2 above.

Response:

David Jendras - Ameren - Ameren Services - 3 -

Answer Comment: **In our opinion there appears to be an inconsistency between the Standard and the Table of Compliance. The Applicability section 4.1.1 identifies the Transmission Owner as a Functional entity. Requirement R5 identifies the Transmission Owner with responsibility for confirming facilities are located within the BA boundaries. However, in the Table of Compliance Elements for requirement R5, the Transmission Operator is identified with this responsibility under the Severe VSL column. We believe that the Transmission Operator should be changed to Transmission Owner to be consistent with the requirements of the Standard.**

The SDT agrees with your comment about the application to GO and has made the change as you suggested.

Response:

Carol Chinn - Florida Municipal Power Agency - 4 -

Group Name: FMPA

Group Member Name	Entity	Region	Segments
Tim Beyrle	City of New Smyrna Beach	FRCC	4
Jim Howard	Lakeland Electric	FRCC	3
Greg Woessner	Kissimmee Utility Authority	FRCC	3
Lynne Mila	City of Clewiston	FRCC	3
Javier Cisneros	Fort Pierce Utility Authority	FRCC	4
Randy Hahn	Ocala Utility Services	FRCC	3
Don Cuevas	Beaches Energy Services	FRCC	1
Stan Rzad	Keys Energy Services	FRCC	4
Matt Culverhouse	City of Bartow	FRCC	3
Tom Reedy	Florida Municipal Power Pool	FRCC	6
Steven Lancaster	Beaches Energy Services	FRCC	3
Mike Blough	Kissimmee Utility Authority	FRCC	5
Mark Brown	City of Winter Park	FRCC	3
Mace Hunter	Lakeland Electric	FRCC	3

Answer Comment: see question2

Response:

Scott McGough - Georgia System Operations Corporation - 3 -

Answer Comment:	1. R7 seems to not even fit with the stated purpose of FAC-001-3 for interconnecting (lowercase) to Facilities. What is the purpose of R7? Capitalized term “Interconnection” simply means “When capitalized, any one of the three major electric system networks in North America: Eastern, Western, and ERCOT.” Reading the requirement at face value…if your load is anywhere in Eastern, Western , or ERCOT Interconnection area then confirm its in a BA Area’s metered boundaries. Is the intent of R7 to identify **which** BA area the load is in? or is the intent to simply identify “yes” it is in “a BAs Area’s metered boundary”? How does knowing or not knowing this have adverse impacts on the reliability of the BES with respect to the purpose of the standard? In addition, note that from NERC’s filing to FERC – *Supplemental Information to Petition for Approval of Proposed Transmission Operations and Interconnection Reliability Operations and Coordination Reliability Standards*, RM15-16, dated May 12, 2015 – NERC states that “An LSE does not own or operate Bulk Electric System facilities or equipment or the facilities or equipment used to serve end-use customers.21 (footnote 21 - The Distribution Provider is the functional entity that provides facilities that interconnect an end-use customer load and the electric system for the transfer of electrical energy to the end-use customer. If a company registered as an LSE also owned facilities, the company would be registered for other functions as well. 2. Measure M7 implies that LSEs have Facility interconnection requirements when there are no such requirements, thus complicating complying with R7. Does the drafting team intend for the LSE to provide a copy of the Facility interconnection requirements documents they may have received from the TO when requesting to interconnect to the transmission owner?

3. Depending on understanding the true intent of this requirement, we would be in favor for an attestation to be included in the measure, but then … seems like a pointless, administrative requirement that meets P81.

1. The intent of this requirement is to assure all Facilities within the interconnected network are accounted for within the boundaries of a BA. The SDT will suggest additional language changes to FAC-001-3 in accommodate the inclusion of Requirement 1.
2. The LSE has been removed from the standard based on the RBR initiative.
3. The SDT agrees with your comment.

Response:

Douglas Webb - Douglas Webb On Behalf of: Chris Bridges, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1
Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1
James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1
Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 6, 5, 1

Answer Comment: KCP&L incorporates by reference its response to Survey Question No. 2.

Response:

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Group Name: NPCC--Project 2010-14.2.1 Phase 2 of Bal Auth Rel-based Controls - BAL-005-1, BAL-006-3, FAC-001-3

Group Member Name	Entity	Region	Segments
Alan Adamson	New York State Reliability Council, LLC	NPCC	10
David Burke	Orange and Rockland Utilities Inc.	NPCC	3
Greg Campoli	New York Independent System Operator	NPCC	2
Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
Mark Kenny	Northeast Utilities	NPCC	1
Helen Lainis	Independent Electricity System Operator	NPCC	2
Rob Vance	New Brunswick Power Corporation	NPCC	9
Paul Malozewski	Hydro One Networks Inc.	NPCC	1
Bruce Metruck	New York Power Authority	NPCC	6
Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
Brian Robinson	Utility Services	NPCC	8
Wayne Sipperly	New York Power Authority	NPCC	5
Edward Bedder	Orange and Rockland Utilities Inc.	NPCC	1
Michael Jones	National Grid	NPCC	1
Brian Shanahan	National Grid	NPCC	1
Glen Smith	Entergy Services, Inc.	NPCC	5
RuiDa Shu	Northeast Power Coordinating Council	NPCC	10
Connie Lowe	Dominion Resources Services, Inc.	NPCC	5
Guy Zito	Northeast Power Coordinating Council	NPCC	10

Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
Robert Pellegrini	The United Illuminating Company	NPCC	1
Kathleen Goodman	ISO - New England	NPCC	2

Answer Comment:

Given that NERC is in the process of delisting the LSE from the Functional Model and the NERC registry, suggest revising Requirement R7 to read "Each **Distribution Provider** that provides facilities that interconnect a customer Load shall confirm that each customer Load is within a Balancing Authority Area's metered boundaries." Measure M7 would need to be revised accordingly.

This standard is unnecessary given the fact that Interconnection Agreements are contractual legal documents that address and spell out the details addressed by the various FAC-001 requirements.

Also, the use of the requirement "shall address" is not a clear mandate and is open to interpretation by both the Responsible Entity and the Regional Enforcement entity.

The wording in Measures M5 thru M7 appear to have been copied from Measures M3 and M4, mentioning "dated, documented Facility interconnection requirements addressing the procedures" as evidence that the requirements are met. The wording in these Measures is appropriate for M3 and M4, but not M5 thru M7.
The LSE has been removed from the standard based on the RBR initiative.

The SDT disagrees with your assertion that this Requirement is not necessary. FAC-001-3 may require contractual legal documents but it does not insist that all elements of the Interconnection be included within the boundaries of a BA. The SDT has modified FAC-001-3 to help clarify the issues.

Response:

Jason Snodgrass - Georgia Transmission Corporation - 1 -

Answer Comment:

In addition to the comments GTC listed in Question 2, GTC believes the response to R5 as a TO would simply be "yes" and is unaware how this answer enhances reliable operation of the BES. Therefore, GTC does not quite understand the intent of these requirements as they are written. Confirm which BA Area the Transmission Facility is located in? Confirm to whom? GTC see's this as administrative in nature subject to P81 criteria.

The original intent was to assure all <u>Facilities</u> within the interconnected network are accounted for within the boundaries of a BA allowing for balance of Demand and Resources. The SDT will suggest additional language changes to FAC-001-3 in accommodate the inclusion of Requirement 1.

Response:

Mike ONeil - NextEra Energy - Florida Power and Light Co. - 1 -

Answer Comment:

We appreciate the work by the SDT, but do not agree with moving BAL-005-0.2b Requirement R1 to FAC-001-3 Requirements R5, R6, and R7. At this time, the way the BAL-005 requirement R1 reads it poses to be more of an accounting issue versus a reliability issue. One alternative solution is to remove the language from this standard (FAC-001-3) and include it in the Application Guidelines section.

The intent is to assure all Facilities within the interconnected network are accounted for within the boundaries of a BA. The SDT will suggest additional language changes to FAC-001-3 in accommodate the inclusion of Requirement 1.

Response:

Payam Farahbakhsh - Hydro One Networks, Inc. - 1 -

Answer Comment: Hydro One supports all comments provided by NPCC RSC regarding the draft of FAC-001-3.

Response:

Albert DiCaprio - PJM Interconnection, L.L.C. - 2 - RFC

Group Name: ISO Standards Review Committee

Group Member Name	Entity	Region	Segments
Charles Yeung	SPP	SPP	2
Ben Li	IESO	NPCC	2
Mark Holman	PJM	RFC	2

Kathleen Goodman	ISONE	NPCC	2
Greg Campoli	NYISO	NPCC	2
Ali Miremadi	CAISO	WECC	2
Terry Bilke	MISO	RFC	2
Christina Bigelow	ERCOT	TRE	2

Answer Comment: The SRC recommends that FAC-001-2 be retired

See file attached to Question 1 for the full text of the comments to Question 6

Response:

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Answer Comment: None.

Shawna Speer - Colorado Springs Utilities - 1 -

Group Name: Colorado Springs Utilities

Group Member Name	Entity	Region	Segments
Shawna Speer	Colorado Springs Utilities	WECC	1
Shannon Fair	Colorado Springs Utilities	WECC	6
Charles Morgan	Colorado Springs Utilities	WECC	3

Kaleb Brimhall	Colorado Springs Utilities	WECC	5

Answer Comment:

Again to illustrate the comments in response #2, FAC-001 is a facility interconnection requirement standard so any changes here will be applied to FAC-001 applicable functional entities documented facility interconnection requirements. FAC-001 typically deals with **new interconnections**, so if the intent of the FAC-001-3 R5-R7 is to make sure all transmission, generation, and load are within a BAA metered bounds this is not the correct standard. R7 in its entirety needs to be moved to another standard since it is not clear which interconnection requirement it will fall under (i.e. TO and/or Applicable GO).

The FAC-001 standard can be used to require documented facility interconnection requirements to address BAA metered bounds for all entities **seeking to interconnect**. However to enforce this for BAA metered bounds for those facilities that already exist within FAC-001, the documented facility interconnection requirements would have to retroactively apply for those facilities that already exist. R5-R6 needs to be moved to another standard. The intent is to assure all Facilities within the interconnected network are accounted for within the boundaries of a BA. The SDT will suggest additional language changes to FAC-001-3 in accommodate the inclusion of Requirement 1.

Response:

Jason Smith - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool	SPP	2
Jason Smith	Southwest Power Pool	SPP	2
Ashley Stringer	Oklahoma Municipal Power Authority	SPP	4

Answer Comment:

The first 4 requirements, which make up the existing FAC-001-2, are administrative and should be moved to certification review. The new R5-7 are necessary due to the removal from BAL-005. However as suggested earlier, those requiremetns should also be included in the TO's Facility Interconnection Requirement documents and do not necessarily need to be specific Reliability Standard Requirements. If R1-4 are kept, we recommend changing the phrase "shall address" in R1-4 to "shall include".

The intent is to assure all Facilities within the interconnected network are accounted for within the boundaries of a BA. The SDT will suggest additional language changes to FAC-001-3 in accommodate the inclusion of Requirement 1.

Response:

Erika Doot - U.S. Bureau of Reclamation - 5 -

Answer Comment:

Reclamation agrees with the periodic review team that it is important to verify facilities are within the metered boundaries of a Balancing Authority Area before they are operational, but believes that the requirement should be imposed through interconnection or service agreements rather than a reliability standard. As an alternative, FAC-001-3 R5 through R7 and M5 through M7 could be rephrased to require a one-time confirmation prior to a facility being placed in service.

The intent is to assure all Facilities within the interconnected network are accounted for within the boundaries of a BA. The SDT will suggest additional language changes to FAC-001-3 in accommodate the inclusion of Requirement 1.

Response:

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Additional comments submitted by Louis Slade - Dominion for Q6:

Given that NERC is in the process of delisting the LSE from the Functional Model and the NERC registry, Dominion suggests revising Requirement 7 to read "Each ~~Load-Serving Entity~~ **Distribution Provider** ~~with Load operating in an Interconnection~~ that provides facilities that interconnect an end-use customer load shall confirm that each end-use customer Load is within a Balancing Authority Area's metered boundaries. If this suggestion is accepted by the SDT, corresponding changes would need to be made to Measure 7.

Response: The LSE has been removed from the standard based on the RBR initiative.

Additional comments submitted by Emily Rousseau – MRO NSRF:

1. **The SDT has moved the BAL-005-0.2b Requirement R1 to FAC-001 since it provides for identifying interconnection Facilities and not for calculating Reporting ACE. Do you agree with moving this requirement into the FAC-001-3 standard? If not, please explain in the comment area below.**

☐ Yes
☒ No

Comments: It is not necessary to move this requirement. The SDT is taking a flawed requirement and moving it to another location. The requirement should be improved as follows.

R1. All generation, transmission, and load operating within an Interconnection must be included within the metered boundaries of a Balancing Authority Area.

~~R1.1. Each Generator Operator with generation facilities operating in an Interconnection shall ensure that those generation facilities are included within the metered boundaries of a Balancing Authority Area.~~

~~R1.2. Each Transmission Operator with transmission facilities operating in an Interconnection shall ensure that those transmission facilities are included within the metered boundaries of a Balancing Authority Area.~~

~~R1.3. Each Load-Serving Entity with load operating in an Interconnection shall ensure that those loads are included within the metered boundaries of a Balancing Authority Area.~~

The requirement above was a concept (Control Area Criteria) that was swept into the V0 standard. The only way to prove that everything is within the metered bounds of a BA is via Inadvertent Interchange accounting. R1 should be kept as-is, the sub-bullets removed and the measure for R1 should be:

M1. The Balancing Authority was unable to agree with an Adjacent Balancing Authority when performing Inadvertent Interchange accounting and it was found that the Balancing Authority had an error in its model or tie lines that misstated its Net Actual Interchange value in its Inadvertent Interchange accounting.

4. **Please provide any issues you have on this draft of the BAL-005-1 standard and a proposed solution.**

Comments:

The proposed R1 should be shortened and merged with R7. There need not be mention of "mutually agreed upon" nor "time synchronized". AGC and ACE use real-time values, not hourly values.

BAL-005-1

R1. Each Balancing Authority shall ~~ensure that~~ have a process to operate to common, accurate ~~each~~ Tie-Lines, Pseudo-Ties, and Dynamic Schedules with its ~~an~~ Adjacent Balancing Authorities. ~~is equipped with a mutually agreed upon time synchronized common source to determine hourly megawatt-hour values~~

The measure of this requirement is not logs or voice recordings. NSI is already checked with Inadvertent Accounting and the INT standards. The process that was proposed in R7 could be the validation and measure for R1

If the change to R1 above is made, R7 is no longer necessary.

R8 is redundant with when compared to the suggested wording above for BAL-005-1 R1 and BAL-006 R3.

Additional comments submitted by ISO Standards Review Committee

1. The SDT has modified the definition of Automatic Generation Control (AGC). Do you agree that this modified definition better represents the SDT intent to making resources more inclusive than just the traditional generation resources? If not, please explain in the comment area below.

☐ Yes
☒ No

Comments:
The SRC does not agree with the proposed definition of AGC.

The SRC recommends the following definition for AGC:

Automatic Generation Control (AGC): *A process designed and used to adjust a Balancing Authority's resources to meet the BA's balancing requirements as required by applicable NERC Reliability Standards.*

Rationale:

1. The BAL-005 definitions should not include any references to Automatic Time Error Correction (I ATEC).

   BAL-005 is a NERC standard applicable to all Interconnections - not one of the many regionally-approved standards. This standard is approved for all BAs unless the BA is in a region in which the standard is superseded by a FERC-approved regional standard. As such, the SRC believes the definition and references to Automatic Time Error Correction (I_{ATEC}) should be deleted and left to the regionally-approved regional standard.

2. The following phrases / terms used in the proposed definition of AGC are ambiguous or not precise.

   - Centrally located equipment

     This phrase should be deleted.

     There is no justification to link the definition of Automatic Generation Control (AGC) to a given location given that AGC is a process (software) not equipment (hardware).

   - …that automatically adjusts…

     This phrase should be reworded.
     There is no direct link between an AGC signal and the response of a resource. As written the failure of a resource to respond to an AGC signal would constitute a violation on the part of the BA.

     It would be more correct to state that AGC "is used to adjust resources".

   - …maintain Reporting ACE…

     This phrase should be deleted.

AGC is not designed for reporting purposes. AGC is designed to assist in the control of a BA's balancing of its resources to its NERC mandated balancing obligations.

- Resources utilized under AGC…

  This sentence should be deleted.

  - AGC does not "utilize" resources, but – rather – evaluates resource utilization within a balancing Authority Area to ensure that load and resources remain in balance. More specifically, resources are an input to AGC.
  - The sentence itself is a partial list of supply resources and therefore not critical to defining the term itself.

2. The SDT has moved the BAL-005-0.2b Requirement R1 to FAC-001 since it provides for identifying interconnection Facilities and not for calculating Reporting ACE. Do you agree with moving this requirement into the FAC-001-3 standard? If not, please explain in the comment area below.

☐ Yes
☒ No

Comments:

The SRC supports deleting the R1 requirements in BAL-005-0.2b, and recommends placing the obligation in a certification requirement.

Rationale: (also see response to Question 6 below)

1. BAL-005-0.2b R1 addresses AGC. R1.1 – R1.3 address administrative items that are generally contained within Interconnection Agreements as legal terms and conditions – not as reliability-related concerns or issues
2. If R1 and its sub-requirements were reliability standards, they would result in an unnecessary annual exchange of paperwork between and among asset owners, BAs and the ERO.

3. The SDT has moved the BAL-006-2 Requirement R3 into BAL-005-3 since this requirement directly impacts an entity's ability to calculate an accurate Reporting ACE. Do you agree with moving this requirement into the proposed BAL-005-1 standard? If not, please explain in the comment area below.

☐ Yes
☒ No

Comments:
The SRC opposes the proposal to move BAL-006-2 Requirement R3 into BAL-005-3.

The SRC recommends that BAL-006 be deleted.

Rationale:
The SRC opposes this proposal for the following reasons:

1. The two standards address issues that are in two different time horizons (BAL-005 is a real time horizon (MW), while BAL-006 is an hourly horizon (MWhr). To combine the two standards into a single standard will confuse the objectives of each of these time horizons and the associated functions.
2. The collection of hourly (Inadvertent Interchange) data proposed by the transferred requirement (R3) does not affect the real time calculation of Reporting ACE. BAL-006 is a standard for Inadvertent Interchange which is an after-the-fact accounting function as opposed to BAL-005 which is about real-time reliability function.
3. Real time metering of interconnecting points is better handled as a certification issue given that such metering is relatively static and stable and does not require continuous the continuous review mandated by a reliability standard.
4. The objective of R3 is not clear as currently proposed. Specifically, it is unclear if R3 is meant:
   - As a procedural mandate that BAs use a single real-time point of metering for interconnection points used in the ACE calculation?
   - As a data reporting mandate on meters, that all interconnection point meters have the ability to compute hourly readings? or
   - As a data reporting mandate on BAs to communicate information on interconnection points once an hour to adjacent BAs (in which case there is a need for a time criteria – e.g. send the information within 4 hours of the clock hour).

Additionally, if Requirement R1 is meant as a data reporting requirement, it should have been considered for retirement under the Paragraph 81 concept. If not, additional clarification is needed, *e.g.*, is it a certification requirement that mandates hardware.

The SRC also notes that NERC's Independent Expert Review Panel recommended BAL-006 for retirement because "This is only for energy accounting. Covered by Tagging requirements."

4. Please provide any issues you have on this draft of the **BAL-005-1** standard and a proposed solution.

Comments:
The SRC provides comments on the rationale and language of several requirements below by requirement.

Requirement R1
The SRC recommends:
- The rationale for R1 be reconsidered and corrected.
- The references in R1 to "time-synchronized common source" and "hourly megawatt-hour values " be deleted.

Rationale
The SRC questions the following text in the proposed "*Rationale for Requirement R1*":
- The intent of R1 is to provide accuracy…
- R1 …used in… Reporting ACE, hourly inadvertent energy, and Frequency Response measurements
- It [R1] specifies need for …instantaneous and hourly integrated …tie line flow values
- Common data source requirements also apply …

The intent of R1 is not accuracy (common source metering does not address accuracy). The intent of R1 is to ensure a zero-sum data ensemble for all ACEs.

Contract-based billing meters used for Inadvertent Interchange are not necessarily the same as the real time common source meters used in ACE. The text of R1 is not precise in what is the specific objective for R1. The rationale states R1 is for instantaneous and hourly tie flow values but the text of R1 states it is "…to determine hourly megawatt-hour values."

The final sentence in the Rationale section regarding of other R1 applications is superfluous and should be deleted.

The SRC questions the following text:

- … time-synchronized common source…
- … to determine hourly megawatt-hour values

The phrase "time-synchronized common source" requires explanation.

If two BAs are using a common (MW) source for real time flows, then by definition the values are synchronized. If, on the other hand, R1 only applies to Hourly (Billing) values (MWh) the phrase is still superfluous. However, if the phrase is meant to mandate that all inter-tie meters be synchronized to a common time, then that needs to be explained more clearly.

The SRC agrees that real time (MW) metering of inter-ties requires the use of common sources to both BAs (as per Requirement 8). But given that R1 is focused on hourly megawatt-hour values, the requirement becomes a market/billing issue not a real time issue. In short, the SDT is asked to rewrite R1 in a fashion that clarifies the intent.

Requirement R2

The SRC recommends:

- The rationale for R2 be reconsidered and revised.

Rationale

The proposed "*Rationale for Requirement R2*" overstates its justification. Specifically the rationale states that without frequency "…the BA operator will lack situational awareness and will be **unable** to make correct decisions when maintaining reliability."

The SRC does not agree that a BA would be “unable” to make correct decisions. The SRC acknowledges that decision-making regarding impacts on and the support for frequency may be more difficult. However, this difficulty does not threaten the reliability of the interconnection as tie line flows will still be monitored by TOPs and system frequency will be monitored by other BAs, TOPs and RCs.

Requirement R4

The SRC recommends that sub-requirements (4.1 and 4.2) be deleted.

Rationale:

The SRC recognizes the value of monitoring system frequency, but suggests that the monitoring of the availability and accuracy of frequency-monitoring equipment is a data collection and reporting exercise that is onerous and administrative in nature. Such requirements would be better suited to be addressed as part of a certification process or in guidance documents than as a mandatory reliability standard.

In lieu of deleting the sub-requirements, the SRC requests the justification for the values in R4.1 and 4.2, and for the benefits to reliability that is to be obtained through the proposed requirements.

Requirement R5

The SRC recommends:

- R5 be addressed as part of a certification process.
- The rationale for R5 be reconsidered and revised.

Rationale

The SRC believes R5 (alarming) would be better addressed in certification than as part of a reliability standard that is subject to continuous review as a reliability standard requirement. The systems that are certified should have alarming processes built into them that are customized to the needs of the respective BA. Such systems, once reviewed, are relatively static and not subject to frequent modification. Additionally, although the SRC recognizes the values of alarming, it is concerned that, in the context of a mandatory reliability standard, subjectivity will be introduced regarding what constitutes “quality” for quality flags, and “invalid” for invalid data. Without an objective measure for the aforementioned terms, Requirement R5 loses any value as a reliability standard.

The proposed "*Rationale for Requirement R5*" states "When an operator questions the validity of data, actions **are delayed** and the probability of **adverse events** occurring **can increase**." While the above could be true, there is no objective evidence to support the statement and therefore the statement should be deleted.

Requirement R6

The SRC recommends requirement R6 be deleted.

Rationale

The SRC recognizes the value of monitoring ACE calculation, but suggests the monitoring of the availability of the software, etc. utilized to calculate ACE is a data collection and reporting exercise that is onerous and administrative in nature. Such requirements are better addressed during the certification process and in guidance documentation than as part of a mandatory reliability standard.

The SRC is concerned that certain terms such as "available system" create ambiguity, e.g., what would constitute an "available system." Neither the requirement nor the measurement makes clear what an available system is nor when a system would be deemed unavailable, e.g., is a system "unavailable" to compute ACE if a single data sample is unavailable? Or when the entire system is unavailable.

Requirement R7

The SRC recommends:

- R7 be deleted.
- The rationale for R7 be reconsidered and revised.

Rationale

The SRC suggests that as written, R7 is an administrative requirement that does not rise to the level of a NERC standard and should be deleted.

Should Requirement R7 be retained, the SRC comments that the objective and obligation of a BA under requirement R7 is ambiguous and requires additional explanation/clarification. Additionally, the process of monitoring for and mitigating data errors that are identified are built into modern EMS systems. Thus, the SDT proposed requirement for an "Operating Process," which is not a defined term in Glossary and should not be considered a proper noun in this requirement, would be redundant of existing processes and functionality. Further, the requirement focuses only on errors "affecting the scan-rate accuracy of data used in the calculation of Reporting ACE…" The SRC asserts that data (in and of itself) generally does not impact the accuracy of the rate of scanning, which is a built in function to the EMS / SCADA programs. The data (good or bad) is scanned regularly.

The *Rationale for R7* states that "…Without a process to address persistent errors in the ACE calculation, the operator can lose trust in the validity of Reporting ACE resulting in delayed or incorrect decisions regarding the reliability of the bulk electric system."

The SRC requests that either justification and support for this statement be provided, or the statement be deleted from the rationale section.

Requirement R8

The SRC recommends:

- R8 be reviewed and revised.
- The *Rationale for R8* be reconsidered and revised.

Rationale

The SRC believes that the issue of common source metering for all inter-ties, and of agreements on allocating resources as pseudo-ties or dynamic schedules is best handled as Interconnection Agreements or certification rather than as a reliability standard.

The SRC notes that Requirement 8 includes Pseudo-ties and Dynamic Schedules but Pseudo-ties and Dynamic Schedules are not tie lines, but are output values from resources. In some cases these output values can be used directly, but in other cases the values are adjusted by the EMS to represent the proportion of the output to be incorporated into the BAs ACE, and thus do not derive from common source meters.

The *Rationale for R8* states that "…When data sources are not common, confusion can be created between BAs resulting in delayed or incorrect operator action." The SRC objects to this statement.

If data sources are not common, then the ACE values in an Interconnection no longer form a zero-sum system. Such an error can only be identified in a tie-line by tie-line check. The result can be all BAs meet the Control Performance requirements, but the Interconnection itself is experiencing an imbalance that results in off-schedule frequency and time error. The SRC would point out that any inaccuracies or errors in the ACE components are reflected in various other parameters:

- System Frequency
- Time Error
- End of Day checkouts
- End of Month billing

Thus, no confusion would result and this should be deleted form the rationale
The *Rationale for Requirement R8* also states "The intent of Requirement R8 is to provide accuracy in the measurement and calculations." Common source metering does not provide accuracy as the data can still be in error. What common source metering does provide is a zero-sum system. Thus, the SRC requests that the rationale be modified to more accurately reflect the impact of data sources on accuracy.

5. Please provide any issues you have on the proposed change to the **BAL-006-3** standard and a proposed solution.

Comments:
The SRC recommends that BAL-006 be retired.

Rationale:
Inadvertent Interchange is an accounting metric not reliability metric.

The BAL-006 requirements are administrative mandates related to after-the-fact accounting should be retired under Paragraph 81.

Any value of Inadvertent Interchange is as an internal control process and would best be memorialized in a form other than a standard.

6. Please provide any issues you have on the proposed change to the **FAC-001-3** standard and a proposed solution.

   Comments:
   The SRC recommends that FAC-001-2 be retired (also see response to Question 2 above)

   Rationale:
   1. Requirements R1 – R4 address administrative items that are generally contained within Interconnection Agreements as legal terms and conditions – not as reliability-related concerns or issues
   2. Requirements R5-R7 are certification issues. If these requirements were reliability standards, they would result in an unnecessary annual exchange of paperwork between and among asset owners, BAs and the ERO.

End of report