Consideration of Comments

Project 2010-14.1 Phase I of Balancing Authority-based Controls: Reserves BAL-001-2

The Standard Drafting Team thanks all commenters who submitted comments on the BAL-001-2 standard. There were 55 sets of comments, including comments from approximately 178 different people from approximately 100 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

Based on industry comments the drafting team made the following clarifying modifications to the proposed standard and associated documents.

- Made clarifying changes to the proposed standard including adding the term "…in accordance with…" in Requirement R2.
- Made clarifying changes to the definition for Reporting ACE.
- Modified the effective date to allow for 12 months to prepare for compliance with BAAL.
- Corrected typographical errors in all documents.

There were a couple of minority issues that the team was unable to resolve, including the following:

- Many stakeholders felt that using BAAL could cause increased inadvertent flows and transmission issues. The drafting team explained that they had not seen any such issues described occur during the field trial that could be directly attributable to the use of BAAL. BAAL was designed to provide for better control by allowing power flows that do not have a detrimental effect on reliability but restrict those that do have a detrimental effect on reliability.
- A couple of stakeholders were concerned that a small BAs operation could be more restrictive under BAAL. The drafting team stated that they were aware of the concern identified. However, the drafting team was attempting to develop a standard that would be applicable to the entire continent and did not know of any method to distinguish between larger and smaller BAs.
- A few stakeholders questioned the value of creating a Regulation Reserve Sharing Group. The drafting team explained that they did not want to rule out any tool that could be used to satisfy compliance within a standard. The drafting team was not mandating that a BA had to participate in a RRSG but could if it was determined to be in their best interest.
- One stakeholder expressed the need for an exemption from compliance during an EEA Level 1, 2, or 3 since they were a single BA Interconnection. The SDT explained that they discussed their concern but came to the conclusion that they did not believe that granting a exemption from compliance was in the best interest of reliability.

All comments submitted may be reviewed in their original format on the standard's 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 Vice President and Director of Standards, Mark Lauby, at 404-446-2560 or at mark.lauby@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/files/Appendix_3A_StandardsProcessesManual_20120131.pdf

Index to Questions, Comments, and Responses

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

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Carmen Agavriloai	Independent Electricity System Operator	NPCC	2
3.	Greg Campoli	New York Independent System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
8.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
9.	Michael Jones	National Grid	NPCC	1
10.	David Kiguel	Hydro One Networks Inc.	NPCC	1
11.	Christina Koncz	PSEG Power LLC	NPCC	5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10

12.	Randy MacDonald	New Brunswick Power Transmission	NPCC	9
13.	Bruce Metruck	New York Power Authority	NPCC	6
14.	Silvia Parada Mitchell	NExtEra Energy, LLC	NPCC	5
15.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
16.	Robert Pellegrini	The United Illuminating Company	NPCC	1
17.	Si-Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
18.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
19.	Brian Robinson	Utility Services	NPCC	8
20.	Brian Shanahan	National Grid	NPCC	1
21.	Wayne Sipperly	New York Power Authority	NPCC	5
22.	Donald Weaver	New Brunswick System Operator	NPCC	2
23.	Ben Wu	Orange and Rockland Utilities	NPCC	1

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2.	Group	paul haase	seattle city light	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	pawel krupa	seattle city light	WECC	1
2.	dana wheelock	seattle city light	WECC	3
3.	hao li	seattle city light	WECC	4
4.	mike haynes	seattle city light	WECC	5
5.	dennis sismaet	seattle city light	WECC	6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3.	Group	Russel Mountjoy-Secretary	MRO NERC Standards Review Forum	X		X	X	X	X				X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alice Ireland	Xcel Energy	MRO	1, 3, 5
2.	Joseph DePoorter	MGE	MRO	3, 4, 5, 6
3.	Dan Inman	MPC	MRO	1, 3, 5, 6
4.	Dave Rudolf	BEPC	MRO	1, 3, 5, 6
5.	Jodi Jensen	WAPA	MRO	1, 6
6.	Ken Goldsmith	ALTW	MRO	4
7.	Lee Kittleson	OTP	MRO	1, 3, 5
8.	Marie Knowx	MISO	MRO	2
9.	Mike Brytowski	GRE	MRO	1, 3, 5, 6

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

10. Scott Bos	MPW	MRO	1, 3, 5, 6
11. Scott Nickels	RPU	MRO	4
12. Terry Harbour	MEC	MRO	1, 3, 5, 6
13. Tom Breene	WPS	MRO	3, 4, 5, 6
14. Tony Eddleman	NPPD	MRO	1, 3, 5

				1	2	3	4	5	6	7	8	9	10
4.	Group	Robert Rhodes	SPP Standards Review Group		X								

Additional Member	Additional Organization	Region	Segment Selection
1. Allan George	Sunflower Electric Power Corporation	SPP	1
2. Bo Jones	Westar Energy	SPP	1, 3, 5, 6
3. Tiffany Lake	Westar Energy	SPP	1, 3, 5, 6
4. Jerry McVey	Sunflower Electric Power Corporation	SPP	1
5. Kevin Nincehelser	Westar Energy	SPP	1, 3, 5, 6
6. Bryan Taggart	Westar Energy	SPP	1, 3, 5, 6

				1	2	3	4	5	6	7	8	9	10
5.	Group	Stuart Goza	SERC OC Standards Review Group	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Jeff Harrison	AECI	SERC	1, 3, 5, 6
2. Ray Phillips	AMEA	SERC	4
3. David Jendras	Ameren	SERC	1, 3
4. Kevin Johnson	Big Rivers	SERC	1
5. Colby Brett Bellville	Duke	SERC	1, 3, 5, 6
6. Mike Lowman	Duke	SERC	1, 3, 5, 6
7. Tom Pruitt	Duke	SERC	1, 3, 5, 6
8. Jim Case	Enteregy	SERC	1, 3, 6
9. Phil Whitmer	Georgia Power Company	SERC	3
10. Wayne Van Liere	LGE-KU	SERC	1, 3, 5, 6
11. Terry Bilke	MISO	SERC	2
12. Brad Gordon	PJM	SERC	2
13. Bill Thigpen	PowerSouth	SERC	1, 5
14. Tim Hattaway	Power South	SERC	1, 5
15. Sammy Roberts	Progress Energy	SERC	1, 3, 5, 6
16. Troy Blalock	SCE&G	SERC	1, 3, 5, 6

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

17. Glenn Stephens	SCPSA	SERC	1, 3, 5, 6
18. Rene Free	SCPSA	SERC	1, 3, 5, 6
19. Tom Abrams	SCPSA	SERC	1, 3, 5, 6
20. John Rembold	SIPC	SERC	1
21. Cindy Martin	Southern	SERC	1, 5
22. Jimmy Cummings	Southern	SERC	1, 5
23. Jimmy Cummings	Southern	SERC	1, 5
24. Randy Hubbert	Southern	SERC	1, 5
25. Kelly Casteel	TVA	SERC	1, 4, 5, 6

				1	2	3	4	5	6	7	8	9	10
6.	Group	Greg Rowland	Duke Energy	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Doug Hils	Duke Energy	RFC	1
2. Lee Schuster	Duke Energy	FRCC	3
3. Dale Goodwine	Duke Energy	SERC	5
4. Greg Cecil	Duke Energy	RFC	6

				1	2	3	4	5	6	7	8	9	10
7.	Group	Brent Ingebrigtson	PPL NERC Registered Affiliates	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Brenda Truhe	PPL Electric Utilities Corporation	RFC	1
2. Annette Bannon	PPL Generation, LLC on behalf of Supply NERC Registered Affiliates	RFC	5
3.		WECC	5
4. Elizabeth Davis	PPL EnergyPlus, LLC	MRO	6

				1	2	3	4	5	6	7	8	9	10
8.	Group	Larry Raczkowski	FirstEnergy	X		X	X	X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. William Smith	FirstEnergy Corp	RFC	1
2. Cindy Stewart	FirstEnergy Corp	RFC	3
3. Doug Hohlbaugh	Ohio Edison	RFC	4
4. Ken Dresner	FirstEnergy Solutions	RFC	5
5. Kevin Querry	FirstEnergy Solutions	RFC	6

				1	2	3	4	5	6	7	8	9	10
9.	Group	Lloyd A. Linke	Western Area Power Administration	X					X				

Additional Member	Additional Organization	Region	Segment Selection
1. Western Area Power Administration	Upper Great Plains Region	MRO	1, 6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10

2.	Western Area Power Administration	Rocky Mouontain Region	WECC	1, 6
3.	Western Area Power Administration	Desert Southwest Region	WECC	1, 6
4.	Western Area Power Administration	Sierra Nevada Region	WECC	1, 6
5.	Western Area Power Administration	Colorado River Storage Project	WECC	6

10.	Group	Marie Knox	MISO Standards Collaborators		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Joe O'Brein	NIPSCO	RFC	6

11.	Group	H. Steven Myers	ERCOT		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Matt Morais	ERCOT	ERCOT	2
2.	Sandip Sharma	ERCOT	ERCOT	2
3.	Matt Stout	ERCOT	ERCOT	2
4.	Ken McIntyre	ERCOT	ERCOT	2
5.	Stephen Solis	ERCOT	ERCOT	2
6.	Vann Weldon	ERCOT	ERCOT	2
7.	Jeff Healy	ERCOT	ERCOT	2

12.	Group	Jason Marshall	ACES Standards Collaborators						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Megan Wagner	Sunflower Electric Power Corporation	SPP	1
2.	John Shaver	Arizona Electric Power Cooperative	WECC	4, 5
3.	John Shaver	Southwest Transmission Cooperative	WECC	1
4.	Michael Brytowski	Great River Energy	MRO	1, 3, 5, 6

13.	Group	Dennis Chastain	Tennessee Valley Authority	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	DeWayne Scott		SERC	1
2.	Ian Grant		SERC	3
3.	David Thompson		SERC	5
4.	Marjorie Parsons		SERC	6

14.	Group	Terri Pyle	Oklahoma Gas & Electric	X		X		X					

	Additional Member	Additional Organization	Region	Segment Selection

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
1.	Terri Pyle	Oklahoma Gas & Electric	SPP	1
2.	Donald Hargrove	Oklahoma Gas & Electric	SPP	3
3.	Leo Staples	Oklahoma Gas & Electric	SPP	5

				1	2	3	4	5	6	7	8	9	10
15.	Group	Brenda Hampton	Luminant						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Rick Terrill	Luminant Generation Company LLC	ERCOT	5

				1	2	3	4	5	6	7	8	9	10
16.	Group	Terry Bilke	IRC-SRC		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Stephanie Monzon	PJM	RFC	2
2.	Ben Li	IESO	NPCC	2
3.	Kathleen Goodman	ISONE	NPCC	2
4.	Charles Yeung	SPP	SPP	2
5.	Ali Miremadi	CAISO	WECC	2

				1	2	3	4	5	6	7	8	9	10
17.	Group	Patricia Robertson	BC Hydro and Power Authority	X	X	X		X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Venkataramakrishnan Vinnakota	BC Hydro and Power Authority	WECC	2
2.	Pat G. Harrington	BC Hydro and Power Authority	WECC	3
3.	Clement Ma	BC Hydro and Power Authority	WECC	5

				1	2	3	4	5	6	7	8	9	10
18.	Group	Jamison Dye	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Bart McManus		WECC	1
2.	Fran Halpin		WECC	5
3.	David Kirsch		WECC	1
4.	Ayodele Idowu		WECC	1
5.	Pam VanCalcar		WECC	5
6.	Don Watkins		WECC	1

				1	2	3	4	5	6	7	8	9	10
19.	Individual	Bob Steiger	Salt River Project	X		X		X	X				
20.	Individual	Janet Smith, Regulatory Affairs Supervisor	Arizona Public Service Company	X		X		X	X				
21.	Individual	Ryan Millard	PacifiCorp	X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
22.	Individual	Stephanie Monzon	PJM Interconnection, L.L.C		X								
23.	Individual	Pamela R. Hunter	Southern Company: Southern Company Services, Inc; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	X		X		X	X				
24.	Individual	Dan O'Hearn	Powerex Corp.						X				
25.	Individual	Tom Siegrist	EnerVision, Inc.							X			
26.	Individual	John Tolo	Tucson Electric Power Co	X									
27.	Individual	Rich Hydzik	Avista	X		X		X					
28.	Individual	Nazra Gladu	Manitoba Hydro	X		X		X	X				
29.	Individual	Anthony Jablonski	ReliabilityFirst										X
30.	Individual	Joe Tarantino	SMUD	X		X	X	X	X				
31.	Individual	Jim Cyrulewski	JDRJC Associates LLC	X									
32.	Individual	Greg Travis	Idaho Power Company	X									
33.	Individual	Michael Falvo	Independent Electricity System Operator			X							
34.	Individual	Howard F. Illian	Energy Mark, Inc.								X		
35.	Individual	Don Schmit	Nebraska Public Power District	X		X		X					
36.	Individual	Kenneth A Goldsmith	Alliant Energy				X						
37.	Individual	Andrew Gallo	City of Austin dba Austin Energy	X		X	X	X	X				
38.	Individual	Angela P Gaines	Portland General Electric Company	X		X		X	X				
39.	Individual	Kathleen Goodman	ISO New England Inc.		X								
40.	Individual	Thad Ness	American Electric Power	X		X		X	X				
41.	Individual	John Seelke	Public Service Enterprise Group	X		X		X	X				
42.	Individual	Linda Horn	Wisconsin Electric Power Company			X	X	X					
43.	Individual	Don Jones	Texas Reliability Entity										X

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
44.	Individual	Oliver Burke	Entergy Services, Inc. (Transmission)	X		X		X	X				
45.	Individual	Brian Murphy	NextEra Energy	X		X		X	X				
46.	Individual	Robert Blohm	Keen Resources Ltd.								X		
47.	Individual	Bill Fowler	City of Tallahassee			X							
48.	Individual	Karen Webb	City of Tallahassee					X					
49.	Individual	Scott Langston	City of Tallahassee	X									
50.	Individual	Christopher Wood	Platte River Power Authority	X		X		X	X				
51.	Individual	Spencer Tacke	Modesto Irrigation District			X	X		X				
52.	Individual	Gregory Campoli	NYISO		X								
53.	Individual	John Bee on Behalf or Exelon and its Affiliates	Exelon	X		X		X					
54.	Individual	Keith Morisette	Tacoma Power	X		X	X	X	X				
55.	Individual	Alice Ireland	Xcel Energy	X		X		X	X				

If you support the comments submitted by another entity and would like to indicate you agree with their comments, please select "agree" below and enter the entity's name in the comment section (please provide the name of the organization, trade association, group, or committee, rather than the name of the individual submitter).

Summary Consideration:

Organization	Supporting Comments of "Entity Name"
Luminant	Electric Reliability Council of Texas (ERCOT)
City of Austin dba Austin Energy	ERCOT
JDRJC Associates LLC	Midwest ISO
Wisconsin Electric Power Company	Midwest ISO
FirstEnergy	MISO
Alliant Energy	MRO NSRF
NYISO	Northeast Power Coordinating Council
Public Service Enterprise Group	PJM Interconnection
Platte River Power Authority	Public Service Company of Colorado (Xcel Energy)
Tennessee Valley Authority	SERC OC Standards Review Group
Entergy Services, Inc. (Transmission)	SERC OC Standards Review Group

1. **The BARC SDT has developed two new terms to be used with this standard. Regulation Reserve Sharing Group: A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply the regulating reserve required for all member Balancing Authorities to use in meeting applicable regulating standards. Regulation Reserve Sharing Group Reporting ACE: At any given time of measurement for the applicable Regulation Reserve Sharing Group, the algebraic sum of the Reporting ACEs (as calculated at such time of measurement) of the Balancing Authorities participating in the Regulation Reserve Sharing Group at the time of measurement. Do you agree with the proposed definitions in this standard? If not, please explain in the comment area below.**

Summary Consideration: Many of the commenters expressed concern that creating a Regulating Reserve Sharing Group conflicted with Reserve Sharing Group or was not clear in its use. The SDT explained that Reserve Sharing Group is already a defined term in the NERC Glossary (for contingency reserve sharing). The SDT was proposing to add a definition that applies to regulating reserve sharing. The SDT appreciates your comments, and has added language to the Background Document to provide clarity. In addition, the SDT is not mandating that a BA has to participate in a RRSG but could if it was determined to be in their best interest. The SDT is simply providing an additional tool for BAs to use and did not want to rule out any tool that could be used to satisfy compliance within a standard.

Several commenters questioned the need to create a definition for Reporting ACE. The SDT stated that the intent was to create a standard term for ACE that was flexible enough to not require development of a regional standard. The SDT has chosen not to include a generic time error correction term in the Reporting ACE equation definition. The SDT has modified the definition to address concerns raised by the industry.

Some commenters stated that the Regulating Reserve Sharing Group was not in either the Functional Model or any NERC registry. The SDT explained that the Regulating Reserve Sharing Group would be added to the NERC Compliance Registry prior to implementation of this standard.

The majority of the commenters provided typographical corrections that needed to be made to the standard and its associated documents.

Organization	Yes or No	Question 1 Comment
ACES Standards Collaborators	No	(1) How does this standard “specifically preclude general improvements

Organization	Yes or No	Question 1 Comment
		to PRC-005-2"? By introducing a new project for PRC-005, the entire standard is subject to revision. The previous standard could be modified and there are no scope restrictions to this project under the NERC Rules of Procedure. There is nothing to preclude changes to Protection Systems. The drafting team should be aware of these implications and reconsider the development of this project, as the last draft took almost seven years to gain industry approval. Further, the Commission has not even ruled on the pending standard, so there is still a tremendous amount of uncertainty as to whether any additional directives or modifications need to be made to PRC-005-2.(2) We have serious concerns with the new definitions being proposed in this draft standard. We feel this excessiveness terms are unnecessary when the standard is only adding a new type of device to an entity's existing maintenance and testing procedure.(3) For example, the "Auto Reclosing" definition is vague and requires further interpretation. What does "such as anti-pump and 'various' interlock circuits" mean? "Various" is not a clear adjective to describe interlock circuits. We recommend revising the entire definition to clearly state the scope of the devices, or better yet, strike the definition from the standard.(4) The term "unresolved maintenance issue" is plain language with a common meaning, and therefore does not need to be introduced as a defined glossary term. This definition could lead to more zero defect compliance and enforcement treatment. What happens if a maintenance issue is not identified as unresolved? Shouldn't a registered entity's internal controls address these issues? Also, this term is missing the other half of the standard - the testing of these devices. It's possible to have an unresolved testing issue as well. (5) The Commission set limitations on the autoreclosing devices that should be included in Order No. 758. An autoreclosing relay should be tested and maintained, "if it either is used [1] in coordination with a Protection System to achieve or meet system performance

Organization	Yes or No	Question 1 Comment
		requirements established in other Commission-approved Reliability Standards, or [2] can exacerbate fault conditions when not properly maintained and coordinated, then excluding the maintenance and testing of these reclosing relays will result in a gap in the maintenance and testing of relays affecting the reliability of the Bulk-Power System." This is problematic because the primary purpose of reclosing relays is to allow more expeditious restoration of lost components of the system, not to maintain the reliability of the Bulk-Power System. This standard would improperly include many types of reclosing relays that do not necessarily affect the reliability of the Bulk-Power System.(6) Order No. 758 (P. 26), the Commission stated that "the standard should be modified, through the Reliability Standards development process, to provide the Transmission Owner, Generator Owner, and Distribution Provider with the discretion to include in a Protection System maintenance and testing program only those reclosing relays that the entity identifies as having an affect on the reliability of the Bulk-Power System." (7) There are concerns with the supplementary reference document because it assumes that PRC-005-2 will be approved by the Commission. This assumption is misleading and should not reflect any Commission rulings that have yet to occur. We recommend stating the current status of the PRC-005-2 project, which was filed with FERC in February 2013 and is pending the Commission's approval. Statements such as "PRC-005-2 'replaced' PRC-011" should be modified to "PRC-005-2 will replace PRC-011 upon approval from FERC," or something similar. (8) The drafting team stated that it reviewed the NERC System Analysis and Modeling Subcommittee (SAMS) "Considerations for Maintenance and Testing of Autoreclosing Schemes - November 2012." SAMS concluded that automatic reclosing is largely implemented throughout the BES as an operating convenience, and that automatic reclosing malâ€performance affects BES reliability only when the reclosing is part of a Special Protection System, or when inadvertent

Organization	Yes or No	Question 1 Comment
		reclosing near a generating station subjects the generation station to severe fault stresses. This report is concluding that these devices do not result in a gap and do not affect the reliability of the Bulkâ€Power System, unless very specific circumstances arise as in the instance where reclosing relays are a part of an SPS scheme. This technical document does not support the development of the standard; rather, the report refutes the need to include these devices in the standard's applicability.
Response: The BARC standards drafting team believes that this answer does not apply to the proposed BAL-001-2 standard.		
Duke Energy	No	Duke Energy agrees that special provisions may be necessary to capture the combined BAAL performance of two BAs operating under a Supplemental Regulation agreement so that one BA can't reset the 30-minute compliance clock of the other BA with a change to the dynamic interchange; however, we are concerned that these definitions could be interpreted to mean that three or more BAs could operate as one, sharing regulation, while the Standards lack sufficient detail behind how the associated interchange of such a group would be tagged or otherwise captured to ensure that the transmission impact is evaluated and subject to curtailment similar to other interchange. When a BA is formed from multiple BAs, its anticipated operation, impact on neighboring systems, and readiness to operate are evaluated - in some cases seams agreements have been required to address adjacent system concerns. The idea that multiple BAs could get together and form a Regulation Reserve Sharing Group (with the potential to impact neighboring systems no differently than is a single BA) without such scrutiny could have reliability implications. Regulation Reserve Sharing Group is not currently included in the NERC Functional Model. The process for registering such a group would have to be addressed for compliance. The words "regulating reserve" should be capitalized in the

Organization	Yes or No	Question 1 Comment
		definition of RRSG.
Response: Reserve Sharing Group is already a defined term in the NERC Glossary (for contingency reserve sharing). The SDT was proposing to add a definition that applies to regulating reserve sharing. The SDT appreciates your comments, and has added language to the Background Document to provide clarity. In addition, the SDT is not mandating that a BA has to participate in a RRSG but could if it was determined to be in their best interest. The SDT is simply providing an additional tool for BAs to use and did not want to rule out any tool that could be used to satisfy compliance within a standard.		
American Electric Power	No	It is not clear what exact intent the drafting team has in the introduction of the term “Regulation Reserve Sharing Group”. This term is specified in the Applicability section, so is it the drafting team’s intent to propose that this new term be established as a new Functional Entity? If that is not the intent, we believe it is mistaken to specify any applicability to any grouping that does not have formal, registered members.
Response: Reserve Sharing Group is already a defined term in the NERC Glossary (for contingency reserve sharing). The SDT was proposing to add a definition that applies to regulating reserve sharing. The SDT appreciates your comments, and has added language to the Background Document to provide clarity. In addition, the SDT is not mandating that a BA has to participate in a RRSG but could if it was determined to be in their best interest. The SDT is simply providing an additional tool for BAs to use and did not want to rule out any tool that could be used to satisfy compliance within a standard.		
PJM Interconnection, L.L.C	No	PJM disagrees with the Interconnection specific inclusion of IATEC in the Reporting ACE definition. The definition of ACE is internationally recognized. It is inappropriate for the SDT to change that definition because of one region in North America. PJM believes all Interconnections should adhere to a common ACE equation definition and that Interconnection specific differences should be addressed through development of a regional standard, as was BAL-004-WECC-01.
Response: The SDT appreciates your comments. The intent was to create a standard term for ACE that was flexible enough to		

Organization	Yes or No	Question 1 Comment
not require development of a regional standard. The SDT has chosen not to include a generic time error correction term in the Reporting ACE equation definition. The SDT has modified the definition to address concerns raised by the industry.		
Bonneville Power Administration	No	The definition of Regulation Reserve Sharing Group (RRSG) does not match the Applicability section. The above definition states that the pooled regulating reserves are used by the member balancing authorities to meet applicable regulating standards. I don't think this is technically correct. The balancing authority that is a member of an RRSG basically transfers its obligations to the RSSG as Responsible Entity. The BA is only the Responsible Entity during periods where they are not in active status with the RRSG. Suggested rewording: End the sentence after the second occurrence of "Balancing Authorities" and delete "to use in meeting applicable regulating standards". This may be sufficient but would probably be better if the following were added to the end: "When Balancing Authorities which are in active status and operating under the rules of an RRSG, the RRSG becomes the Responsible Entity for Standard Requirements related to Regulating Reserves for the member Balancing Authorities.
Response: Reserve Sharing Group is already a defined term in the NERC Glossary (for contingency reserve sharing). The SDT was proposing to add a definition that applies to regulating reserve sharing. The SDT appreciates your comments, and has added language to the Background Document to provide clarity. In addition, the SDT is not mandating that a BA has to participate in a RRSG but could if it was determined to be in their best interest. The SDT is simply providing an additional tool for BAs to use and did not want to rule out any tool that could be used to satisfy compliance within a standard.		
Northeast Power Coordinating Council	No	The need to create the two new terms (RRSG and RRSG Reporting ACE) and the applicability exceptions for BAs that receives overlap regulation service or participate in the RRSG is not apparent. The Standard should stipulate the requirements for each BA to meet the CPS1 and BAAL requirements only, regardless of how it arranges for the regulation services to meet these requirements. Suggest removing the two new

Organization	Yes or No	Question 1 Comment
		terms, and the applicability exception for BAs receiving overlap regulation service or participating in the RRSG. The current posted version appears to place requirements on both individual BAs and the RRSG, but the obligations for the latter are not clearly stipulated in the Standard. There is no need to have the latter (RRSG) requirements stipulated for the RRSG so long as the Standard places the obligation to each BA to meet the CPS1 and BAAL requirements. The first term (RRSG) is used in the Applicability section and should be used in R1. However, the proposed Standard allows for overlap and supplemental regulation and hence a BA may obtain regulation services through these mechanisms only; there is no requirement for the RRSG to comply with group CPS1 or report RRSG ACE in the Standard, nor is the RRSG Reporting ACE calculation depicted in the Attachments. We suggest removing these new terms. The term “RRSG” is used in the Applicability section of the Standard and concern was raised about continued use of new terms not specifically in the Functional Model, along with any specific tasks and roles for these newly defined “entities”. Should the Functional Model Working Group (FMWG) review the proposed definition and consider the RRSG as an addition for the NERC Version 6 of the Functional Model? We suggest that NERC set up a process whereby all proposals for newly defined entities be vetted and cleared through the FMWG.
Response: The SDT appreciates your comments. Reserve Sharing Group is already a defined term in the NERC Glossary (for contingency reserve sharing). The SDT was proposing to add a definition that applies to regulating reserve sharing. The SDT appreciates your comments, and has added language to the Background Document to provide clarity. In addition, the SDT is not mandating that a BA has to participate in a RRSG but could if it was determined to be in their best interest. The SDT is simply providing an additional tool for BAs to use and did not want to rule out any tool that could be used to satisfy compliance within a standard. The intent was to create a standard term for ACE that was flexible enough to not require development of a regional standard. The SDT has chosen not to include a generic time error correction term in the Reporting ACE equation definition. The		

Organization	Yes or No	Question 1 Comment
SDT has modified the definition to address concerns raised by the industry. The Regulating Reserve Sharing Group will be added to the NERC Compliance Registry prior to this standard becoming effective.		
ISO New England Inc.	No	The need to create the two new terms (RRSG and RRSG Reporting ACE) and the applicability exceptions for BAs that receives overlap regulation service or participate in the RRSG is not apparent. The Standard should stipulate the requirements for each BA to meet the CPS1 and BAAL requirements only, regardless of how it arranges for the regulation services to meet these requirements. Suggest removing the two new terms, and the applicability exception for BAs receiving overlap regulation service or participating in the RRSG. The current posted version appears to place requirements on both individual BAs and the RRSG, but the obligations for the latter are not clearly stipulated in the Standard. There is no need to have the latter (RRSG) requirements stipulated for the RRSG so long as the Standard places the obligation to each BA to meet the CPS1 and BAAL requirements. The first term (RRSG) is used in the Applicability section and should be used in R1. However, the proposed Standard allows for overlap and supplemental regulation and hence a BA may obtain regulation services through these mechanisms only; there is no requirement for the RRSG to comply with group CPS1 or report RRSG ACE in the Standard, nor is the RRSG Reporting ACE calculation depicted in the Attachments. We suggest removing these new terms. The term "RRSG" is used in the Applicability section of the Standard and concern was raised about continued use of new terms not specifically in the Functional Model, along with any specific tasks and roles for these newly defined "entities". Should the Functional Model Working Group (FMWG) review the proposed definition and consider the RRSG as an addition for the NERC Version 6 of the Functional Model? We suggest that NERC set up a process whereby all proposals for newly defined entities be vetted and cleared

Organization	Yes or No	Question 1 Comment
		through the FMWG.
Response: The SDT appreciates your comments. Reserve Sharing Group is already a defined term in the NERC Glossary (for contingency reserve sharing). The SDT was proposing to add a definition that applies to regulating reserve sharing. The SDT appreciates your comments, and has added language to the Background Document to provide clarity. **The intent was to create a standard term for ACE that was flexible enough to not require development of a regional standard. The SDT has chosen not to include a generic time error correction term in the Reporting ACE equation definition. The SDT has modified the definition to address concerns raised by the industry.** **The Regulating Reserve Sharing Group will be added to the NERC Compliance Registry prior to this standard becoming effective.**		
Powerex Corp.	No	The proposed definitions have not been adequately justified for inclusion in the standard. The background document does not provide any additional information or reasons for inclusion of these definitions.
Response: The SDT appreciates your comments. The SDT has developed these terms for the following reasons. **The intent was to create a standard term for ACE that was flexible enough to not require development of a regional standard. The SDT has chosen not to include a generic time error correction term in the Reporting ACE equation definition. The SDT has modified the definition to address concerns raised by the industry.** **Reserve Sharing Group is already a defined term in the NERC Glossary (for contingency reserve sharing). The SDT was proposing to add a definition that applies to regulating reserve sharing. The SDT appreciates your comments, and has added language to the Background Document to provide clarity. In addition, the SDT is not mandating that a BA has to participate in a RRSG but could if it was determined to be in their best interest. The SDT is simply providing an additional tool for BAs to use and did not want to rule out any tool that could be used to satisfy compliance within a standard.**		
Modesto Irrigation District	No	This concept violates the very definition of a balancing authority (control area).
Response: The SDT appreciates your comments. Unfortunately, the SDT would need additional information to provide a response to your comment.		

Organization	Yes or No	Question 1 Comment
Independent Electricity System Operator	No	We do not see the need to create these terms. We understand that the first term (RRSG) is used in the applicability section and arguable in R1. However, the proposed standard allows for overlap and supplemental regulation and hence a BA may obtain regulation services through these mechanisms only; there is no requirement for the RRSG to comply with group CPS1 or report RRSG ACE in the standard, nor is the RRSG Reporting ACE calculation depicted in the Attachments. We suggest removing these new terms. Furthermore, since the term RRSG is in the applicability section of the standard, it implies that this is a new functional entity. In order for this term to have applicability, it needs to have defined roles. This definition should be vetted through the functional model working group and included in the functional model PRIOR to being included in BAL-001.
Response: Reserve Sharing Group is already a defined term in the NERC Glossary (for contingency reserve sharing). The SDT was proposing to add a definition that applies to regulating reserve sharing. The SDT appreciates your comments, and has added language to the Background Document to provide clarity. In addition, the SDT is not mandating that a BA has to participate in a RRSG but could if it was determined to be in their best interest. The SDT is simply providing an additional tool for BAs to use and did not want to rule out any tool that could be used to satisfy compliance within a standard. **The intent was to create a standard term for ACE that was flexible enough to not require development of a regional standard. The SDT has chosen not to include a generic time error correction term in the Reporting ACE equation definition. The SDT has modified the definition to address concerns raised by the industry.** **The Regulating Reserve Sharing Group will be added to the NERC Compliance Registry prior to this standard becoming effective.**		
MRO NERC Standards Review Forum	No	We don’t understand the reasoning for these new definitions. Balancing Authorities have an Area Control Error. The standards presently allow for overlap and supplemental regulation that allow a BA to obtain regulation services, which appears to be the driver for these definitions. We also cannot find in a SAR associated with this project that proposes to change BAL-001. While the Reliability Based Control

Organization	Yes or No	Question 1 Comment
		standard is referenced in the changes, RBC deals with a 30 minute limit on ACE and not redefinition of ACE and the creation of new entities.
Response: The SDT appreciates your comments. Reserve Sharing Group is already a defined term in the NERC Glossary (for contingency reserve sharing). The SDT was proposing to add a definition that applies to regulating reserve sharing. The SDT appreciates your comments, and has added language to the Background Document to provide clarity. In addition, the SDT is not mandating that a BA has to participate in a RRSG but could if it was determined to be in their best interest. The SDT is simply providing an additional tool for BAs to use and did not want to rule out any tool that could be used to satisfy compliance within a standard. **The SDT is not attempting to redefine ACE. The intent was to create a standard term for ACE that was flexible enough to not require development of a regional standard. The SDT has chosen not to include a generic time error correction term in the Reporting ACE equation definition. The SDT has modified the definition to address concerns raised by the industry. In addition, the SDT is proposing to move the definition out of the BAL-001 standard and into the NERC Glossary as they feel it applies to multiple standards.** **The Regulating Reserve Sharing Group will be added to the NERC Compliance Registry prior to this standard becoming effective.**		
MISO Standards Collaborators	No	We don't understand the reasoning for these new definitions. Balancing Authorities have an Area Control Error. The standards presently allow for overlap and supplemental regulation that allow a BA to obtain regulation services, which appears to be the driver for these definitions. We also cannot find in a SAR associated with this project that proposes to change BAL-001. While the Reliability Based Control standard is referenced in the changes, RBC deals with a 30 minute limit on ACE and not redefinition of ACE and the creation of new entities.
Response: The SDT appreciates your comments. Reserve Sharing Group is already a defined term in the NERC Glossary (for contingency reserve sharing). The SDT was proposing to add a definition that applies to regulating reserve sharing. The SDT appreciates your comments, and has added language to the Background Document to provide clarity. In addition, the SDT is not mandating that a BA has to participate in a RRSG but could if it was determined to be in their best interest. The SDT is simply providing an additional tool for BAs to use and did not want to rule out any tool that could be used to satisfy compliance within		

Organization	Yes or No	Question 1 Comment
a standard. The SDT is not attempting to redefine ACE. The intent was to create a standard term for ACE that was flexible enough to not require development of a regional standard. The SDT has chosen not to include a generic time error correction term in the Reporting ACE equation definition. The SDT has modified the definition to address concerns raised by the industry. In addition, the SDT is proposing to move the definition out of the BAL-001 standard and into the NERC Glossary as they feel it applies to multiple standards. The Regulating Reserve Sharing Group will be added to the NERC Compliance Registry prior to this standard becoming effective.		
IRC-SRC	No	We don't understand the reasoning for these new definitions. Balancing Authorities have an Area Control Error. The standards presently allow for overlap and supplemental regulation that allow a BA to obtain regulation services, which appears to be the driver for these definitions. We also cannot find in a SAR associated with this project the need to change the definitions.
Response: The SDT appreciates your comments. Reserve Sharing Group is already a defined term in the NERC Glossary (for contingency reserve sharing). The SDT was proposing to add a definition that applies to regulating reserve sharing. The SDT appreciates your comments, and has added language to the Background Document to provide clarity. In addition, the SDT is not mandating that a BA has to participate in a RRSG but could if it was determined to be in their best interest. The SDT is simply providing an additional tool for BAs to use and did not want to rule out any tool that could be used to satisfy compliance within a standard. The SDT is not attempting to redefine ACE. The intent was to create a standard term for ACE that was flexible enough to not require development of a regional standard. The SDT has chosen not to include a generic time error correction term in the Reporting ACE equation definition. The SDT has modified the definition to address concerns raised by the industry. In addition, the SDT is proposing to move the definition out of the BAL-001 standard and into the NERC Glossary as they feel it applies to multiple standards. The Regulating Reserve Sharing Group will be added to the NERC Compliance Registry prior to this standard becoming effective.		
SMUD	No	While the definitions are acceptable, terminology within the standards

Organization	Yes or No	Question 1 Comment
		that call these discrete entities would be better identified as an overarching Reserve Sharing Group that would encompass the various terms: RRSG, RRSGRA ect. Recommend replacing all unique terminology to only include the Reserve Sharing Group in the BAL-001.
Response: The SDT appreciates your comments. Reserve Sharing Group is already a defined term in the NERC Glossary (for contingency reserve sharing). The SDT was proposing to add a definition that applies to regulating reserve sharing. The SDT appreciates your comments, and has added language to the Background Document to provide clarity. In addition, the SDT is not mandating that a BA has to participate in a RRSG but could if it was determined to be in their best interest. The SDT is simply providing an additional tool for BAs to use and did not want to rule out any tool that could be used to satisfy compliance within a standard.		
Texas Reliability Entity	Yes	1) The equation in the definition of Reporting ACE in the Standard is different than the one in the Implementation Plan (left off the WECC ATEC). 2) The Regulation Reserve Sharing Group Reporting ACE definition is different here than the Reserve Sharing Group Reporting ACE definition provided in BAL-002-which is correct? (Note “at the time of measurement” as last part of sentence)
Response: The SDT appreciates your comments. **1) The SDT has corrected this error.** **2) The SDT has corrected this and is now using a single term.**		
Manitoba Hydro	Yes	Although Manitoba Hydro agrees with the definitions, we have the following suggestions: (1) NIA (Actual Net Interchange) - capitalize the word ‘tie lines’ because it appears in the Glossary of Terms. (2) NIS (Scheduled Net Interchange) - capitalize the word ‘tie lines’

Organization	Yes or No	Question 1 Comment
		because it appears in the Glossary of Terms. Also, the words ‘Net Interchange Actual’ should be rewritten as ‘Net Actual Interchange’ and the word ‘Interchange’ de-capitalized in ‘scheduled Interchange’. (3) Regulation Reserve Sharing Group - capitalize the word ‘regulating-reserve’ because it appears in the Glossary of Terms. Also, the ‘-’ should be removed from ‘regulating-reserve’. (4) Reporting ACE - capitalize the word ‘net actual interchange’. Also, add ‘net’ to ‘scheduled interchange’ and capitalize, because definitions appear in the Glossary of Terms. (5) 10 - capitalize ‘frequency bias setting’. (6) IME (Interchange Meter Error) - the words ‘net interchange actual (NIA)’ should be re-written as ‘Net Actual Interchange’ and capitalized. Also, de-capitalize the last instance of ‘Interchange’. (7) IATEC (Automatic Time Error Correction) - capitalize the word interconnection’. (8) H - de-capitalize ‘Hours’ or is this a Clock Hour? (9) PIIaccum - capitalize the words ‘interconnection’, ‘net interchange schedules’, ‘net interchange’, and ‘scheduled frequency’.

Response: Thank you for your comments.

1) **The SDT has made the correction that you have identified.**
2) **The SDT has made the correction that you have identified.**
3) **The SDT has made the correction that you have identified.**
4) **The SDT has made the correction that you have identified.**
5) **The SDT has made the correction that you have identified.**
6) **The SDT is purposely using “Net Interchange Actual” per the definition shown in the standard. The SDT has corrected the interchange.**

Organization	Yes or No	Question 1 Comment
7) **The SDT has made the correction that you have identified.** 8) **The SDT has made the correction that you have identified.** 9) **The SDT has made the correction that you have identified.**		
seattle city light	Yes	There are differing references to Regulating Reserve Sharing Group and Reserve Sharing Group between BAL-001-2 and BAL-002-2. Seattle City Light recommends consistent terminology across the Standards.
Response: The SDT appreciates your comments. The SDT has corrected this and is now using a single term.		
SERC OC Standards Review Group	Yes	We are concerned that the term "Reporting ACE" used in this definition has a different historic meaning than what is being formalized in this proposed standard. We recommend labeling this term as "Regulation Reporting ACE."
Response: The SDT appreciates your comments. The SDT is trying to provide a consistent measure of ACE to apply across all standards.		
SPP Standards Review Group	Yes	
PPL NERC Registered Affiliates	Yes	
ERCOT	Yes	
Oklahoma Gas & Electric	Yes	
Salt River Project	Yes	
Arizona Public Service Company	Yes	
PacifiCorp	Yes	

Organization	Yes or No	Question 1 Comment
Southern Company: Southern Company Services, Inc; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	
EnerVision, Inc.	Yes	
Tucson Electric Power Co	Yes	
Avista	Yes	
Idaho Power Company	Yes	
Energy Mark, Inc.	Yes	
Portland General Electric Company	Yes	
Keen Resources Ltd.	Yes	
City of Tallahassee	Yes	
City of Tallahassee	Yes	
City of Tallahassee	Yes	
Tacoma Power	Yes	
Xcel Energy	Yes	

2. **If you are not in support of this draft standard, what modifications do you believe need to be made in order for you to support the standard? Please list the issues and your proposed solution to them.**

Summary Consideration: Several commenters did not believe that the field trial had produced any positive results and that the Western Interconnection was experiencing problems associated with the use of BAAL. The SDT explained that BAAL had been under Field Trial since July 2005 on the Eastern Interconnection, January 2010 in ERCOT, March 2010 on the Western Interconnection, and January 2011 in Quebec. Voluntary field trials are only as good as the willingness of the participants. NERC cannot force BAs to participate. The Standard Drafting Team feels that a Field Trial with a duration approaching eight years should be sufficient to evaluate a standard. Concerning the Field Trial on the Western Interconnection, the WECC has chosen to take local responsibility for its evaluation and consequently only shared limited data with NERC. The reports supplied by the WECC have indicated that there are still unknowns associated with the standard, but they have failed to indicate any significant reliability impacts that can be attributed to the BAAL.

Some commenters felt that this standard was moving in the wrong direction and actually relaxing control performance. The SDT stated that the appropriate goal for NERC in standards development should not only be to improve reliability, it should also be to set reliability levels such that the additional value of improved reliability is more than the additional cost of achieving that reliability improvement. If this is the case then there may be times when the value of reducing reliability is less than the savings resulting from reduced reliability. Taking any other view will result in inappropriate reliability decisions for the customers. The SDT further explained that they were focusing in on one of the measures of reliability which is frequency. Both user's and supplier's equipment are designed to operate in a safe frequency range. By focusing on frequency we provide the ability to meet this reliability goal.

Many commenters stated that there were unscheduled flow that created imbalances going in to a BAs ACE and Inadvertent Interchange Balances. The SDT responded that unscheduled energy flows that do not cause reliability problems are not reliability issues. Since these issues are not reliability problems they should not be resolved by a reliability standard. The BAAL Field Trial has provided new information concerning the determination of the contribution of unscheduled energy to transmission reliability. However, the BARC SDT determined that it was beyond their scope to take action to implement changes in standards or procedures to restrict the effects of unscheduled energy flows on transmission loading.

A few commenters expressed concern that the use of BAAL benefited larger users. The SDT explained that they were unable to determine whether the difference between BAAL and CPS2 limits is due to: 1) BAAL inappropriately discriminating against small BAs; or, 2) CPS2 inappropriately favoring small BAs. However, the BARC SDT was able to determine that

BAAL provides a guarantee that if all BAs are operating within their BAAL the interconnection frequency error will remain less than the frequency trigger limit. The BARC SDT was unable to find a way to modify BAAL to retain the frequency guarantee and provide additional operating margin for the small BAs.

A few other commenters felt that since there was no averaging of ACE (other than the one minute averaging within the metric) it would allow for large deviations in ACE for prolonged periods of time. The SDT stated that the reliability standards should not be viewed in isolation. They work together to achieve operating characteristics that are greater than individual requirements. BAAL only addresses the duration of large ACE deviations, however, at the same time CPS1 prevents a BA from accumulating significant repetitive durations with large ACE deviations by providing a CPS1 score in excess of 800% below passing levels for each minute that the BAAL is exceeded.

A couple of commenters did not feel that the six month window prior to implementation of BAAL would allow sufficient time to prepare. The SDT stated that they agreed and modified the effective date to allow for a twelve month window to prepare for compliance.

A few commenters felt that creating a Regulating Reserve Sharing Group provided no benefit. The SDT explained that the SDT was not mandating that a BA had to participate in a RRSG but could if it was determined to be in their best interest. The SDT is simply providing an additional tool for BAs to use and did not want to rule out any tool that could be used to satisfy compliance within a standard.

Organization	Yes or No	Question 2 Comment
ACES Standards Collaborators	No	(1) The SDT needs to clarify the implementation plan. The document is confusing because it focuses on the PRC-005-2 standard, which is not yet FERC-approved. This implementation plan is a constantly changing moving target. Why not wait until PRC-005-2 gets approved before initiating another project for the same standard? This would reduce some of the timing issues and confusion.(2) Why is the drafting team revising a standard that has not been approved by the Commission yet? The second version was only filed in February 2013, and the timing of this project is premature. It is quite possible that the Commission could remand or revise parts of the standard and issue other directives

Organization	Yes or No	Question 2 Comment
		associated with the version 2, which would then need to be addressed. This project is untimely and should be postponed until there is a final order from FERC. At that point, there may be justification to continue with this project, expand the scope of the SAR to address any new directives that may be included in a final order of PRC-005-2, or to determine that a guidance document is an appropriate way to satisfy the FERC orders.(3) The Commission specifically advised the drafting team of PRC-005-2 to modify the standard to include reclosing relays. Because the drafting team did not include them during that opportunity, the drafting team should wait until a final order is issued.(4) Again, the drafting team needs to consider other methods of answering FERC directives. Not every directive needs to be addressed by developing or revising a standard. Adding reclosing relays to PRC-005 only complicates the most-violated non-CIP standard. There is enough concern about this standard already and the drafting team should consider alternative means to address the reclosing relay issue besides a standard revision.(5) This project contains similar timing issues as CIP version 4 and CIP version 5 because it is being developed prior to FERC issuing a final order on the previous version of the standard. The timing is problematic; registered entities will be forced to constantly be focusing on the next standard. The implementation plan should provide additional time, similar to PRC-005-2's two intervals, to allow registered entities enough time to adjust their PSMT programs for Protection Systems, and then have additional time to adjust their PSMT plan and implement autoreclosers.(6) Thank you for the opportunity to comment.
Response: Thank you for your comment. Unfortunately, the comment you provided does not appear to address draft Standard BAL-001-2.		
Bonneville Power Administration	No	1. The impacts of the field trial have not been analyzed thoroughly enough to put this to a vote at this time. In the WECC, we have seen an

Organization	Yes or No	Question 2 Comment
		increase in frequency deviations, the number of manual time error corrections, coordinated phase shifter operations, and unscheduled flow during the period of the field trial. It is not entirely clear to what extent the Field Trial is responsible for these increases. The data collected has not been made available to the individual Entities for analysis and evaluation. At the NERC level there is some information posted but it is not in great enough detail to be able to make a decision on the merits or risks associated with the BAAL standard. One piece of information which seems blatantly missing is the degree to which participating BA's have detuned their AGC systems for the field trial. Without this information it seems an objective analysis of the impacts would be impossible. If we are seeing an increase in the number of frequency excursions yet the participating BA's have only minimally (or not at all) detuned their AGC algorithms then we may unknowingly be sitting on the brink of reliability disaster should the standard pass and BA' fully detune their AGC systems to take full advantage of the new requirements. 2. The tools for managing path flows with respect to larger allowed deviations by participating BAs did not keep up with the RBC pilot. 3. BAL-001 is driven by economics, not reliability. It is easy to assess the $$$ gains by operating to BAAL, but the additional costs incurred to your Balancing Authority because of another Balancing Authority's operation within the BAAL envelope is not easily calculated. Within NERC and in general, a system operating at 60 Hz is more reliable than one operating at some other value; however, there is no proof that the BAAL operating range is unreliable. Studies must be run on the WECC system with off-nominal frequency. This has been brought up in study team meetings, but the studies have yet to be performed. 4. This standard seems to be moving contrary to the general trend of standards development. While all other standards seem to be aiming for

Organization	Yes or No	Question 2 Comment
		improvements to reliable system operations this standard is going the other direction by considerably relaxing the Control Performance Standards. It is difficult to understand how a standard which allows a BA to accumulate extremely large negative ACE - potentially in the minutes just prior to a major MSSC event - could possibly be an improvement for reliability. From the control required of CPS2, this appears to be a lowering of the bar. 5. Any field trial results in addition to the limitations pointed out in 2. Above, are further tainted by the fact that not all BA's are participating in the field trial. Only about 2/3rds of the total frequency bias of the Eastern Interconnection is represented by BA's in the field trial. In the WECC that percentage is higher but it is known that not all of the "participating" BA's have changed their control algorithms and for the BA's that have; the magnitude of the control system changes are not known. 6. There are a variety of commercial issues being raised by entities familiar with the field trial. The issues range from transmission system flows and transmission rights being usurped by unscheduled flow to issue of imbalances being allowed to go into a BA's ACE and Inadvertent Interchange balances. 7. Large Balancing Authorities benefit disproportionately to small Balancing Authorities. Under certain conditions, small Balancing Authorities may experience a more narrow operating bandwidth under the proposed BAL-001-1 than under the existing BAL-001. 8. There is no averaging of ACE, other than the one minute average used in the metric. This allows large deviations in ACE for prolonged periods of time, up to 29 minutes, without any adverse consequences to the BA with respect to this standard.

Organization	Yes or No	Question 2 Comment
		9. At this point in time BPA sees no simple solution to these issues. More information needs to be collected from Balancing Authorities taking part in the field trial and that information needs to be made more available to all interested parties. More extensive analysis needs to be done before any informed decisions can be made on this dramatic change to the control performance standards. 10. BPA believes that the analysis done during the field trials have been conducted with incomplete information, most notably they are lacking information on exactly what changes, if any, participating BA's have made to their control systems. 11. BPA believes that the proposed standard reduces the control performance measures by allowing "looser" control and is therefore, less stringent than the current standard, It is hard to understand how a loosening of the control performance standards can provide an increase in reliability.

Response: Thank you for your comments.

1. **The Standard Drafting Team appreciates you concern with respect to uncertainty associated with the Field Trial Results. However, the BAAL has been under Field Trial since July 2005 on the Eastern Interconnection, January 2010 in ERCOT, March 2010 on the Western Interconnection, and January 2011 in Quebec. Voluntary field trials are only as good as the willingness of the participants. NERC cannot force BAs to participate. The Standard Drafting Team feels that a Field Trial with a duration approaching eight years should be sufficient to evaluate a standard. Concerning the Field Trial on the Western Interconnection, the WECC has chosen to take local responsibility for its evaluation and consequently only shared limited data with NERC. The reports supplied by the WECC have indicated that there are still unknowns associated with the standard, but they have failed to indicate any significant reliability impacts that can be attributed to the BAAL.**
2. **Managing the tools to control path flows on an interconnection is beyond the scope of the BARC SDT. However, the team did provide a new method for estimating path flows as part of the body of work that was considered during the development of BAAL but was not adopted by the WECC.**
3. **All reliability standards have some economic component. The goal is to balance the economic cost with the reliability cost to**

Organization	Yes or No	Question 2 Comment
achieve the best joint reliability/economic result. Studies performed for FERC indicate that the WECC in general is spending more for secondary frequency control and less for primary frequency control that is economically justified. The SDT believes that BAAL provides the BA with the correct reliability factor, being Frequency, and allows for the coordination among the BAs to move frequency in the correct direction for the reliability of the Interconnection. 4. The appropriate goal for NERC in standards development should not only be to improve reliability, it should also be to set reliability levels such that the additional value of improved reliability is more than the additional cost of achieving that reliability improvement. Taking any other view will result in inappropriate reliability decisions for the customers. 5. Non-participation in a voluntary field trial is not a reason for delaying the implementation of a standard. Field Trials are held for the express purpose of determining whether there are any problems that will arise if the new standard is implemented. The function of NERC is not to tell each BA how to operate their unique portion of the BES, but is instead to set boundaries that define the limits of reliable operations and allow each BA to operate freely within those limits. 6. Unscheduled energy flows that do not cause reliability problems are not reliability issues. Since these issues are not reliability problems they should not be resolved by a reliability standard. The BAAL Field Trial has provided new information concerning the determination of the contribution of unscheduled energy to transmission reliability. However, the BARC SDT determined that it was beyond their scope to take action to implement changes in standards or procedures to restrict the effects of unscheduled energy flows on transmission loading. 7. The BARC SDT was unable to determine whether the difference between BAAL and CPS2 limits is due to: 1) BAAL inappropriately discriminating against small BAs; or, 2) CPS2 inappropriately favoring small BAs. However, the BARC SDT was able to determine that BAAL provides a guarantee that if all BAs are operating within their BAAL the interconnection frequency error will remain less than the frequency trigger limit. The BARC SDT was unable to find a way to modify BAAL to retain the frequency guarantee and provide additional operating margin for the small BAs. 8. The reliability standards should not be viewed in isolation. They work together to achieve operating characteristics that are greater than individual requirements. BAAL only addresses the duration of large ACE deviations, however, at the same time CPS1 prevents a BA from accumulating significant repetitive durations with large ACE deviations by providing a CPS1 score in excess of 800% below passing levels for each minute that the BAAL is exceeded. 9. The SDT posts monthly the available information on the field trial to the NERC website. WECC elected not to release the detailed data from the field trial. The BARC SDT believes eight years of study of these issues is sufficient to make an informed decision. 10. Results based standards provide measureable limits that define reliable operations. Results based standards should not require information about how those results are achieved. They should require only the measured results demonstrate reliable operations. In a results based standard environment, it is inappropriate to judge how the results are achieved; only		

Organization	Yes or No	Question 2 Comment
they are achieved and they will result in an appropriate level of reliability. **11. The SDT is focusing in on one of the measures of reliability which is frequency. Both user's and supplier's equipment are designed to operate in a safe frequency range. By focusing on frequency we provide the ability to meet this reliability goal. Please refer to responses to 3 and 4 above.**		
BC Hydro and Power Authority	No	BCHA applauds the significant improvement made in this proposed standard to add the term Reporting ACE and to create the definition for Regulation Reserve Sharing Group. However, BCHA respectfully submits the following reasons for its Negative vote: 1. The reliability impacts of increased unscheduled flow have not been adequately addressed. BC Hydro suggests studying in detail those events where a BA's ACE was within BAAL however the Reliability Coordinator still instructed the BAs to reduce ACE within L10 to mitigate path transmission loading issues. 2. There is no requirement for BAs to maintain their true load-resource balance, i.e. no requirement for ACE to cross zero during any predetermined scheduling period, or for the averaged ACE over any predetermined scheduling period to be within a reasonable limit about zero. The "base line" of zero-ACE for a true balance can be moved to as far away as the BAAL limit without any consequences to the BA as long the scheduled frequency is maintained (by other BAs with ACE in the opposite sign). Although there is more flexibility for BAs to deploy their resources and some potential benefit gained by reduced wear and tear cost, BAs may interpret BAAL as their rights to withhold their resource commitment. 3. Increased difficulties in the planning time frame for transmission use. The basis for setting aside the Transmission Reliability Margin might have to be revised to account for a wider range of ACE allowed by BAAL. This may lead to a larger transmission margin being made unavailable

Organization	Yes or No	Question 2 Comment
		for commercial use. 4. Increased needs in real time for the RC to monitor SOL/IROL overloading and their instruction to BAs to scale back on ACE magnitude. This might be not practical for an Interconnection with multiple-RCs. It may also raise an inequity issue whereby not all BAs will be asked to refrain from operating with BAAL at the same time. 5. Potential for increased hidden operating costs to Transmission entities such as increased transmission losses caused by BAs exchanging their large imbalances without transmission rights.

Response: Thank you for your comments.

1. **Managing the tools to control path flows on an interconnection is beyond the scope of the BARC SDT. However, the team did provide a new method for estimating path flows as part of the body of work that was considered during the development of BAAL that could be used to determine contribution to path flows. ACE is not a definitive measure of reliability.**
2. **It is impossible for any BA on a multiple BA interconnection to maintain their load-resource balance (zero ACE) at all times. Therefore, the standard sets limits with respect to how much ACE deviation can be allowed during reliable operations. Even CPS2 does not require a long-term average of ACE that is close to zero. There is no reliability consequence associated with average ACE deviation as calculated for CPS2. The reliability standards should not be viewed in isolation. They work together to achieve operating characteristics that are greater than individual requirements. BAAL only addresses the duration of large ACE deviations, however, at the same time CPS1 prevents a BA from accumulating significant repetitive durations with large ACE deviations by providing a CPS1 score in excess of 800% below passing levels for each minute that the BAAL is exceeded.**
3. **The appropriate goal for NERC in standards development should be more than to merely improve reliability; it should also consider whether reliability levels are set such that the additional value of improved reliability is more than the additional cost of achieving that reliability improvement. As long as the cost of different Transmission Reliability Margin is included in the cost benefit determination of the appropriate level of reliability, the inclusion of the change in Transmission Reliability Margin is appropriate. Taking any other view will result in inappropriate reliability decisions for the customers.**
4. **The WECC study indicated that ACE deviations were as likely to result in decreases in transmission path loading as to result in**

Organization	Yes or No	Question 2 Comment
increases in transmission path loading. The logic presented would be justification not to allow any changes in operations because they might result in these same problems yet changes are made in operations often. During the field trial the SDT has not had any Eastern Interconnection RC identify any issues as you describe. 5. The SDT believes that transmission losses are almost as likely to move upward as they are to move downward. Tightening balancing control standards to address transmission issues is an inappropriate reason to restrict control which can significantly increase costs for everybody.		
ReliabilityFirst	No	ReliabilityFirst votes in the Negative due to the "Regulation Reserve Sharing Group" being an applicable Entity and the fact that there is no functional or Registered Entity defined as a "Regulation Reserve Sharing Group". Absent any Entities registered as a "Regulation Reserve Sharing Group", compliance cannot be assessed against this entity, thus making any requirements applicable to the "Regulation Reserve Sharing Group" unenforceable.
Response: Thank you for your comments. **The SDT will have the Regulation Reserve Sharing Group added to the compliance registry once this standard has been approved by the industry and FERC.**		
seattle city light	No	Seattle City Light supports the implementation of BAAL limits to replace CPS2, but think this draft needs more work and should not be implemented as currently written. It appears to have been rushed. Specifically, Seattle experienced good results in the Reliability Based Controls field trials and supports the RACE and BAAL concepts. However, Seattle has concerns about the compliance risk introduced by the many new definitions and new types of reserve sharing groups proposed under this draft. In particular are the relations among Regulation Reserve Sharing Group, Reserve Sharing Group, and Balancing Authority ability to designate one or another of these groups as responsible entity. For example, as currently written there may be a possibility of conflict between the applicability of BAL-001-2 and Requirement R2 of the

Organization	Yes or No	Question 2 Comment
		Standard. As written Applicability Section 4.0 states the Standard is applicable to: 4.1 Balancing Authority 4.1.2 A balancing Authority that is a member of Regulation Reserve Sharing Group is the Responsible Entity only in period during which the Balancing Authority is not in active status under the applicable agreement or governing rules for the Regulation Reserve Sharing Group. 4.2. Regulation Reserve Sharing Group. Further Requirement R2 of the Standard states that: R2. Each Balancing Authority shall operate such that its clockâ€minute average of ReportingACE does not exceed its clockâ€minute Balancing Authority ACE Limit (BAAL) for morethan 30 consecutive clockâ€minutes, as calculated in Attachment 2, for the applicableInterconnection in which the Balancing Authority operates.[Violation Risk Factor:Medium] [Time Horizon: Realâ€time Operations]Seattle finds the Standard is not clear if requirement R.2 is applicable to the Regulation Reserve Sharing Group as a group or to all BAs individually participating in Regulation Reserve Sharing Group. As currently written a BA can argue that R.2 is not applicable if they are participating in Regulation Reserve Sharing Group, and Seattle is not sure if this was the intent of the Standard Drafting Team. Another example is that Attachment 1 used to describe how to calculate CPS1 does not appear to be complete. It needs to be revised to include the methodology for calculating the CPS1 for the Regulation Reserve Sharing Group. Seattle is also concerned that BAL-001-2 R2 “...more than 30 consecutive clock-minutes...” requirement represents too long a time, and should be changed to a shorter time frame to better reflect the existing and proposed sub-hour scheduling windows and other Standards limiting the time that a Balancing Authority is not positively supporting system

Organization	Yes or No	Question 2 Comment
		frequency.
Response: Thank you for your comments. **Each requirement in a standard is not necessarily applicable to all entities listed in the applicability section. Requirement R2 in the proposed standard is only applicable to the BA. The SDT does not believe that a RRSG can satisfy the requirements of BAAL.** **The SDT has not seen any issues arise during the field trial concerning the 30 clock-minute time window. In addition, the SDT believes that this is complementary with time limits established in transmission related standards. The SDT received no other comments concerning the 30 clock-minute duration for BAAL and believes that it is appropriate.**		
Nebraska Public Power District	No	The applicability section of the standard allows for periods of time when a BA may be responsible for meeting the requirements of this standard and times when a Regulation Reserve Sharing Group may be responsible for meeting the requirements of this standard. However R1 requires calculating a 12 month average CPS 1. Neither the requirement nor the attachment address how a responsible entity is to handle those periods, which may be portions of a month, day or hour when they are not responsible for meeting the requirements. If the period is to be treated as bad data, the standard or attachment that details the calculation needs to specify how those periods are handled. The term “active status” used in section 4.1.2 is not a defined term and may not be included in any regulation reserve sharing agreements. There should be more clarity around this term. Given the concerns noted above, are there minimum time periods when a regulation reserve sharing group may not be in “active status”. For example, can a regulation reserve sharing pool be inactive for a portion of an hour, or conversely only be active for a portion of the hour? The standard needs more clarification on what active status means and how frequently the status can change.

Organization	Yes or No	Question 2 Comment
Response: Thank you for your comments. **The calculation of CPS1 would be the same whether or not a BA participates in a RRSG.** **The SDT included the possibility of active versus inactive status for the potential of events such as, but not limited to telemetry failure.**		
City of Tallahassee	No	The City of Tallahassee (TAL) believes that six months is insufficient time to modify the software, make the changes, and monitor performance in today's CIP world. Cyber standards have progressed significantly since the Standards Drafting Team analyzed the potential timeframes for implementation. TAL contends that 12 months would be more appropriate.
Response: Thank you for your comments. **The SDT agrees with your comment and has modified the standard to provide for 12 months after FERC approval.**		
Western Area Power Administration	No	The impacts of the field trial have not been analyzed thoroughly enough to put this to a vote at this time. In the WECC, we have seen an increase in frequency deviations, the number of manual time error corrections, coordinated phase shifter operations, and unscheduled flow during the period of the field trial. It is not entirely clear to what extent the Field Trial is responsible for these increases. The data collected has not been made available to the individual Entities for analysis and evaluation. At the NERC level there is some information posted but it is not in great enough detail to be able to make a decision on the merits or risks associated with the BAAL standard. One piece of information which seems blatantly missing is the degree to which participating BA's have detuned their AGC systems for the field trial. Without this information it seems an objective analysis of the impacts would be impossible. If we are seeing an increase in the number

Organization	Yes or No	Question 2 Comment
		of frequency excursions yet the participating BA's have only minimally (or not at all) detuned their AGC algorithms then we may unknowingly be sitting on the brink of reliability disaster should the standard pass and BA' fully detune their AGC systems to take full advantage of the new requirements. This standard seems to be moving contrary to the general trend of standards development. While all other standards seem to be aiming for improvements to reliable system operations this standard is going the other direction by considerably relaxing the Control Performance Standards. It is difficult to understand how a standard which allows a BA to accumulate extremely large negative ACE - potentially in the minutes just prior to a major MSSC event - could possibly be an improvement for reliability. From the control required of CPS2, this appears to be a lowering of the bar. The WECC experienced fewer instances where SOL were exceeded, when there was a ACE Transmission Limit of 4 times L sub 10 during the RBC Field Trial. Western recommends that the BARC SDT consider establishing an ACE Transmission Limit for the Western Interconnection. The impacts are not the same for Large Balancing Authorities as they are for small Balancing Authorities. Under certain conditions, small Balancing Authorities may experience a more narrow operating bandwidth under the proposed BAL-001-1 than under the existing BAL-001.

Response: Thank you for your comments.

1. **The Standard Drafting Team appreciates you concern with respect to uncertainty associated with the Field Trial Results. However, the BAAL has been under Field Trial since July 2005 on the Eastern Interconnection, January 2010 in ERCOT, March 2010 on the Western Interconnection, and January 2011 in Quebec. Voluntary field trials are only as good as the willingness of the participants. NERC cannot force BAs to participate. The Standard Drafting Team feels that a Field Trial with a duration**

Organization	Yes or No	Question 2 Comment
approaching eight years should be sufficient to evaluate a standard. Concerning the Field Trial on the Western Interconnection, the WECC has chosen to take local responsibility for its evaluation and consequently only shared limited data with NERC. The reports supplied by the WECC have indicated that there are still unknowns associated with the standard, but they have failed to indicate any significant reliability impacts that can be attributed to the BAAL. 2. Results based standards provide measureable limits that define reliable operations. Results based standards should not require information about how those results are achieved. They should require only the measured results demonstrate reliable operations. In a results based standard environment, it is inappropriate to judge how the results are achieved; only they are achieved and they will result in an appropriate level of reliability. 3. The appropriate goal for NERC in standards development should not only be to improve reliability, it should also be to set reliability levels such that the additional value of improved reliability is more than the additional cost of achieving that reliability improvement. Taking any other view will result in inappropriate reliability decisions for the customers. 4. The Eastern Interconnection has not experienced increases in SOL exceedances that were attributed to the Field Trial; therefore, any fixed ACE Transmission Limit would be inappropriate to add to a continent wide standard. 5. The BARC SDT was unable to determine whether the difference between BAAL and CPS2 limits is due to: 1) BAAL inappropriately discriminating against small BAs; or, 2) CPS2 inappropriately favoring small BAs. However, the BARC SDT was able to determine that BAAL provides a guarantee that if all BAs are operating within their BAAL the interconnection frequency error will remain less than the frequency trigger limit. The BARC SDT was unable to find a way to modify BAAL to retain the frequency guarantee and provide additional operating margin for the small BAs.		
NYISO	No	The NYISO has concerns based on results of the field trials that were conducted. These field trials have indicated the potential for an increased number of SOL violations as well as potential for increased ACE due to large inadvertent flows with the proposed BAAL limits based on frequency triggers. It is not appropriate to indicate the SOL/IROL Standards will address these additional overloads as the flows that are causing the overloads due to the increase ACE are not identifiable in any contingency management system. We would propose dropping the BAAL calculation until a wider field trial could be conducted.
Response: Thank you for your comments.		

Organization	Yes or No	Question 2 Comment
The SDT believes that BAAL provides the BA with the correct reliability factor and allows for the coordination among the BAs to move frequency in the correct direction for the reliability of the Interconnection. The appropriate goal for NERC in standards development should not only be to improve reliability, it should also be to set reliability levels such that the additional value of improved reliability is more than the additional cost of achieving that reliability improvement. Taking any other view will result in inappropriate reliability decisions for the customers. The SDT has focused on frequency as the measure of reliability for this standard. Both user's and supplier's equipment are designed to operate in a safe frequency range. By focusing on frequency we provide the ability to meet this reliability goal. It is the opinion of the SDT that conducting a wider field trial beyond what was conducted in the West, which involved 70% of the BAs, would not provide any additional benefit. Sufficient data exists to support that reliability is not degraded. The SDT believes that the implementation of BAAL as an enforceable standard would result in similar system performance as it relates to transmission flows as presently achieved with CPS 2.		
City of Tallahassee	No	The question above is not a Yes/No question. The City of Tallahassee (TAL) believes that six months is insufficient time to modify the software, make the changes, and monitor performance in today's CIP world. Cyber standards have progressed significantly since the Standards Drafting Team analyzed the potential timeframes for implementation. TAL contends that 12 months would be more appropriate.
Response: Thank you for your comments. The SDT agrees with your comment and has modified the standard to provide for 12 months after FERC approval.		
Avista	No	The RBC Field Trial in the WECC provided enough information to determine if RBC had any effects on reliability. The WECC PWG's July 2012 report to the WECC OC clearly documented frequency error was increasing over previous operation under CPS2. It documented increasing frequency in the negative direction in heavy load hours (particularly morning and evening peaks) and increasing frequency error

Organization	Yes or No	Question 2 Comment
		in the positive direction during light load hours. This report also shows Epsilon 1 and Epsilon 10 increasing significantly over past CPS2 performance years. Manual time error corrections and hours of manual time error corrections are approximately double what they had been. The PWG report documents increasing unscheduled flow events with the ACE Transmission Limit (ATL) being increased or eliminated. This has continued on into 2013. This indicates that RBC has a negative effect on path flow control and management. Increasing inadvertent accumulations are also documented in the PWG report. Increasing inadvertent, unscheduled flow events and curtailments, and prolonged frequency deviations beyond 0.030 Hz are not hallmarks of a reliable system. No studies, or actual events, have demonstrated that the WECC system can perform for a 2800 MW (G-2) generation loss with an initial frequency of 59.94 Hz or lower. Additional control problems are created when frequency deviations beyond 0.030 Hz occur, exceeding governor deadband on generating units (IEEE standard deadband). If these units are being used for Automatic Generation Control (AGC), they will move to governor control, generally disabling the AGC functionality. This does not add to system reliability, and likely detracts from it. The RBC formula advantages larger Balancing Authorities by allowing looser control and wider frequency ranges. Whereas a smaller BA may see the BAAL limits quickly shrink at deviations near 0.050 Hz, a larger BA can still run a large ACE, creating inadvertent flow and secondary control problems for smaller BA's. Finally, loose ACE control effectively eliminates the effectiveness of the WECC Automatic Time Error Correction system. WECC ATEC depends on

Organization	Yes or No	Question 2 Comment
		CPS2 compliance in order to ensure that a BA is continuously paying back its accumulated Primary Inadvertent balance. With the loose limits of RBC, the Primary Inadvertent payback term is small enough that it may not even influence the BA's AGC control algorithm. This can be clearly seen by the increasing WECC frequency deviation beginning with the field trial in 2010. ATEC was implemented in WECC in 2003, and low frequency deviation from 2003-2009 is easily seen the PWG 2012 WECC OC report. R2 is not a frequency control requirement under all conditions, it is a requirement that is used under normal conditions. It is designed to operate around small frequency deviations. For large frequency deviations, frequency support is required and measured by ACE recovery under BAL-002 (DCS). With respect to R2/M2, how many times can a BA exceed BAAL limits for 30 minutes? Can a BA exceed BAAL for 27 minutes every hour? A limit based on so many minutes exceeding BAAL per month or some similar measure may be more likely to incent the desired control performance. How do you measure severity if an event happens many times, but never exceeds 30 minutes? Is 29 minutes ok and 31 minutes a risk to the interconnection? Comments: "BAL-001-1 Real Power Balancing Control Standard Background Document" Page 4 has an illuminating statement."CPS2 is: Designed to limit a Control Area's (now BA) unscheduled power flow." This is a significant issue in the WECC. Unscheduled power flow becomes unmanageable without the CPS2 requirement. There is no other way to control BA to BA power flow if a BA is not required to maintain its Net Actual Interchange within a limit. The summary statement on page 6 is not supported by the field trials. The summary statement says that RBC improves upon CPS2 by

Organization	Yes or No	Question 2 Comment
		dynamically altering ACE limits based on frequency. The WECC field trial conclusively demonstrates that frequency control is worse and frequency error is greater, indicating RBC decreases reliability compared to CPS2. The inability to control path flows effectively, requiring unscheduled flow mitigation to remain within System Operating Limits, inherently decreases reliable operation. CPS2 takes frequency into account with the frequency component of the ACE equation. To claim that operating to the ACE equation does not inherently support system frequency is not logical. The CPS2 requirement should be retained, and the BAAL should not be adopted.

Response: Thank you for your comments.

1. **The Standard Drafting Team appreciates you concern with respect to uncertainty associated with the Field Trial Results. However, the BAAL has been under Field Trial since July 2005 on the Eastern Interconnection, January 2010 in ERCOT, March 2010 on the Western Interconnection, and January 2011 in Quebec. Voluntary field trials are only as good as the willingness of the participants. NERC cannot force BAs to participate. The Standard Drafting Team feels that a Field Trial with a duration approaching eight years should be sufficient to evaluate a standard. Concerning the Field Trial on the Western Interconnection, the WECC has chosen to take local responsibility for its evaluation and consequently only shared limited data with NERC. The reports supplied by the WECC have indicated that there are still unknowns associated with the standard, but they have failed to indicate any significant reliability impacts that can be attributed to the BAAL.**
2. **The WECC Unscheduled Flow Administrative Subcommittee (UFAS) evaluation of 2012 events showed the BAAL to be a relatively minor issue in regards to the events seen. The PWG evaluation was less in depth than the UFAS evaluation.**
3. **As the Interconnection approaches lower frequencies such as 59.94 Hz, BAAL will provide the BA direction to return their ACE closer to zero; whereas CPS2 does not provide the same guidance.**
4. **While ASME had a 36 mHz standard (PTC 20.1-1977 Speed and Load Governing Systems for Steam Generating Units) until 2003, it is no longer a part of any recognized standard of IEEE, ASME or NERC to the knowledge of this SDT. All frequency control results in normal distributions of frequency error. This has been demonstrated on all of the North American Interconnections. Looser ACE control will not eliminate the effectiveness of the WECC ATEC system because the frequency error will still be normally distributed around scheduled frequency. The effectiveness of the inadvertent payback will also**

Organization	Yes or No	Question 2 Comment
continue. AGC should continue to function normally even when units are outside of the deadband. 5. The BARC SDT was unable to determine whether the difference between BAAL and CPS2 limits is due to: 1) BAAL inappropriately discriminating against small BAs; or, 2) CPS2 inappropriately favoring small BAs. However, the BARC SDT was able to determine that BAAL provides a guarantee that if all BAs are operating within their BAAL the interconnection frequency error will remain less than the frequency trigger limit. The BARC SDT was unable to find a way to modify BAAL to retain the frequency guarantee and provide additional operating margin for the small BAs. 6. All frequency control results in normal distributions of frequency error. This has been demonstrated on all of the North American Interconnections. Looser ACE control will not eliminate the effectiveness of the WECC ATEC system because the frequency error will still be normally distributed around scheduled frequency. The effectiveness of the inadvertent payback will also continue. 7. The BAAL is applicable every minute of every day. Exceeding the BAAL for more than 30 clock-minutes will be a violation regardless of frequency level. 8. The reliability standards should not be viewed in isolation. They work together to achieve operating characteristics that are greater the individual requirements. BAAL only addresses the duration of large ACE deviations, however, at the same time CPS1 prevents a BA from accumulating significant repetitive durations with large ACE deviations by providing a CPS1 score in excess of 800% below passing levels for each minute that the BAAL is exceeded. 9. Unscheduled energy flows that do not cause reliability problems are not reliability issues. Since these issues are not reliability problems they should not be resolved by a reliability standard. The BAAL Field Trial has provided new information concerning the determination of the contribution of unscheduled energy to transmission reliability. However, the BARC SDT determined that it was beyond their scope to take action to implement changes in standards or procedures to restrict the effects of unscheduled energy flows on transmission loading. 10. The SDT has focused on frequency as the measure of reliability for this standard. Both user's and supplier's equipment are designed to operate in a safe frequency range. By focusing on frequency we provide the ability to meet this reliability goal. 11. It is correct that CPS2 is affected by frequency through the ACE equation, but the commenter failed to realize that the 10 minute average required in the CPS2 measure can be detrimental to frequency because an average can incent behavior that causes control actions that make frequency worse instead of better.		
City of Tallahassee	No	This is not a yes/no question. The City of Tallahassee (TAL) believes that six months is insufficient time to modify the software, make the changes, and monitor performance in today's CIP world. Cyber standards have progressed significantly since the Standards Drafting

Organization	Yes or No	Question 2 Comment
		Team analyzed the potential timeframes for implementation. TAL contends that 12 months would be more appropriate.
Response: Thank you for your comments. The SDT agrees with your comment and has modified the standard to provide for 12 months after FERC approval.		
Northeast Power Coordinating Council	No	We do not see the need to create the two new terms (RRSG and RRSG Reporting ACE) and the applicability exceptions for BAs that receives overlap regulation service or participate in the RRSG. The Standard should stipulate the requirements for each BA to meet the CPS1 and BAAL requirements only, regardless of how it arranges for the regulation services to meet these requirements. We suggest removing the two new terms, and the applicability exception for BAs receiving overlap regulation service or participating in the RRSG. The currently posted version appears to place requirements on both individual BAs and the RRSG, but the obligations for the latter are not clearly stipulated in the Standard. There is a need to have the RRSG requirements stipulated for the RRSG so long as the Standard places the obligation to each BA to meet the CPS1 and BAAL requirements.
Response: Thank you for your comments. **The SDT has eliminated the term RRSG Reporting ACE.** **The calculation of CPS1 would be the same whether or not a BA participates in a RRSG.** **The SDT is not mandating that a BA has to participate in a RRSG but could if it was determined to be in their best interest. The SDT is simply providing an additional tool for BAs to use and did not want to rule out any tool that could be used to satisfy compliance within a standard.** **The SDT has added clarifying language to Attachment 2 on how bad data is handled for BAAL.**		
ISO New England Inc.	No	We do not see the need to create the two new terms (RRSG and RRSG

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 2 Comment</th></tr>
<tr><td></td><td></td><td>Reporting ACE) and the applicability exceptions for BAs that receives overlap regulation service or participate in the RRSG. The Standard should stipulate the requirements for each BA to meet the CPS1 and BAAL requirements only, regardless of how it arranges for the regulation services to meet these requirements. We suggest removing the two new terms, and the applicability exception for BAs receiving overlap regulation service or participating in the RRSG.The currently posted version appears to place requirements on both individual BAs and the RRSG, but the obligations for the latter are not clearly stipulated in the Standard. There is a need to have the RRSG requirements stipulated for the RRSG so long as the Standard places the obligation to each BA to meet the CPS1 and BAAL requirements.</td></tr>
<tr><td colspan="3">Response: Thank you for your comments.

The SDT has eliminated the term RRSG Reporting ACE.

The calculation of CPS1 would be the same whether or not a BA participates in a RRSG.

The SDT is not mandating that a BA has to participate in a RRSG but could if it was determined to be in their best interest. The SDT is simply providing an additional tool for BAs to use and did not want to rule out any tool that could be used to satisfy compliance within a standard.

The SDT has added clarifying language to Attachment 2 on how bad data is handled for BAAL.</td></tr>
<tr><td>Oklahoma Gas & Electric</td><td>No</td><td>While we appreciate the attempt to streamline and simplify the standard, the requirement of Balancing Authorities providing Overlap Regulation Service should be moved back into the requirements section. The Standard should be enforceable based solely on the Requirements."The most critical element of a Reliability Standard is the Requirements. As NERC explains, "the Requirements within a standard define what an entity must do to be compliant . . . [and] binds an entity to certain obligations of performance under section 215 of the FPA." If</td></tr>
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Organization	Yes or No	Question 2 Comment
		properly drafted, a Reliability Standard may be enforced in the absence of specified Measures or Levels of Non-Compliance.” (NOPR and Order 693)
Response: Thank you for your comments. **Based on conversations with NERC staff, the SDT moved the requirement concerning Overlap Regulation Service to the applicability section. The SDT, as well as NERC staff, did not believe that this should be a requirement.**		
Independent Electricity System Operator	No	While we do not see the need to create the two new terms (RRSG and TTSG Reporting ACE), if the terms were to be included, the term RRSG should be vetted through the functional model working group PRIOR to including it in this standard as it appears to be a new functional entity. As such, it’s roles should be defined in the functional model prior to being incorporated into any NERC standards.We do not see the need to create the two new terms (RRSG and RRSG Reporting ACE) and the applicability exceptions for BAs that receives overlap regulation service or participate in the RRSG. The standard should stipulate the requirements for each BA to meet the CPS1 and BAAL requirements only, regardless of how it arranges for the regulation services to meet these requirements. We suggest removing the two new terms, and the applicability exception for BAs receiving overlap regulation service or participating in the RRSG.We generally supported the previous draft that stipulates the requirements for each BA. We are unable to support the currently posted version as it appears to place requirements on both individual BAs and the RRSG but the obligations for the latter is not clearly stipulated in the standard. At any rate, we do we see a need to have that latter (RRSG) requirements stipulated for the RRSG so long as the standard places obligation to each BA to meet the CPS1 and BAAL requirements.

Organization	Yes or No	Question 2 Comment
Response: Thank you for your comments. **The SDT has eliminated the term RRSG Reporting ACE.** **The calculation of CPS1 would be the same whether or not a BA participates in a RRSG.** **The SDT is not mandating that a BA has to participate in a RRSG but could if it was determined to be in their best interest. The SDT is simply providing an additional tool for BAs to use and did not want to rule out any tool that could be used to satisfy compliance within a standard.** **The SDT has added clarifying language to Attachment 2 on how bad data is handled for BAAL.**		
SPP Standards Review Group	No	With the introduction of the Regulating Reserve Sharing Group there appears to be a registration gap. There currently isn't a Regulating Reserve Sharing Group entity in the Functional Model. It would appear that such a registration would have to be made in order to be able to hold the Regulation Reserve Sharing Group accountable for compliance purposes. Providing this is done, then R1 and R2 should reflect the applicability to both the Balancing Authority and the Regulation Reserve Sharing Group. As written R1 requires any applicable BA to maintain CPS1 for the Interconnection within which it operates at 100 percent or higher. The rolling 12-month calculation needs additional clarification also. We suggest the requirement should be rewritten to read:The Responsible Entity shall operate such that its Control Performance Standard 1 (CPS1), calculated based on the applicable Interconnection in which it operates in accordance with Attachment 1, is greater than or equal to 100 percent for each consecutive 12-month period. Each consecutive 12-month period shall be evaluated monthly. As written, R2 applies only to a Balancing Authority. It should be reworded to apply to both a Balancing Authority or Regulation Reserve Sharing Group as is R1. Substitute Responsible Entity for Balancing

Organization	Yes or No	Question 2 Comment
		Authority in the requirement. Likewise we would suggest deleting the comma following 'Attachment 2' in R2. This links the ending phrase of the sentence to the calculation, where it should be, more tightly. In the last line of Attachment 2, insert 'Overlap' in front of 'Regulation Service'.
Response: Thank you for your comments. **The Regulation Reserve3 Sharing Group will be added to the Compliance Registry prior to the standard going into effect.** **The SDT has added clarifying language to Requirement R1 to address your concern.** **Each requirement in a standard is not necessarily applicable to all entities listed in the applicability section. Requirement R2 in the proposed standard is only applicable to the BA. The SDT does not believe that a RRSG can satisfy the requirements of BAAL.** **The SDT believes that the current writing of Requirement R2 is correct and provides the necessary clarity.** **The SDT has added the word "Overlap" as you suggested.**		
Keen Resources Ltd.	No	
Manitoba Hydro	Yes	Although Manitoba Hydro is in support of the standard, we have the following clarifying suggestions: (1) (Proposed) Effective Date in both the Standard and Implementation Plan - remove the " ' " following the word 'Trustees' because it is not defined this way in the Glossary of Terms. (2) Applicability 4.1.2 - add an 's' on the end of the word 'period'. In addition, add the word 'the' before 'governing rules'. (3) Data Retention - capitalize three instances of 'compliance enforcement authority' in this section.

Organization	Yes or No	Question 2 Comment
		(4) R1 - the words ‘12 month period’ should be changed to ‘rolling 12 month basis’ for consistency with the VSL table. (5) R1 - for clarity, ‘it’ should be specified as the ‘Responsible Entity’. (6) R2/M2 - please clarify if this requirement/measure should refer only to Balancing Authority as opposed to Responsible Entity? (7) R2 - add the words ‘accordance with’ before ‘Attachment 2’. (8) M1, M2 - the term ‘Energy Management System’ is not found in the Glossary and should be defined. (9) VSL, R2 and Attachment 1, CPS1 - add a ‘-’ between the words ‘clock minutes’ for consistency with the standard. In addition, the words ‘for the applicable Interconnection’ should be added for consistency with the language of R2 and the VSL for R1. (10) General - there is inconsistency throughout the standard and Attachments with respect to the following words: ‘12 month period’, ‘rolling 12 month basis’, ‘12-calendar months’, ‘12-month’. We suggest selecting one of these terms and using it throughout the standard and attachments.

Response: Thank you for your comments.

1) **The SDT has made the modification as requested.**
2) **The SDT has made the modification as requested.**
3) **The SDT has made the modification as requested.**
4) **The SDT has added clarifying language to the requirement.**
5) **The SDT believes that the use of the word “it” provides the necessary clarity.**
6) **Each requirement in a standard is not necessarily applicable to all entities listed in the applicability section. Requirement R2 in the proposed standard is only applicable to the BA. The SDT does not believe that a RRSG can satisfy the requirements of BAAL.**
7) **The SDT has made the modification as requested.**

Organization	Yes or No	Question 2 Comment
8) The SDT has removed the term "Energy Management System". **9) The SDT has made the modification as requested.** **10) The SDT has corrected the inconsistency that you have described.**		
MISO Standards Collaborators	Yes	Assuming we are wrong and that the drafting team has authority under their SAR or a specific FERC directive to modify the definitions in BAL-001, we have the following comments. With regard to the ACE equation and the WECC ATEC term, we recommend that the ACE equation be simplified and made such that it would work with any interconnection. We recommend the term IATEC be changed to ITC, which would stand for Time Control. The balancing standards should limit the magnitude of TC to a value such as 20% of Bias. This would work for both the WECC and HQ approach to controlling time error and assisting in inadvertent interchange management (WECC). It would also give the Eastern Interconnection a tool to reduce the number of Time Error Corrections, which will be important if we want to encourage generators to reduce their deadbands under BAL-003-1.
Response: Thank you for your comments. **The SDT has chosen not to include a generic time error correction term in the Reporting ACE equation definition. The SDT has modified the definition to address concerns raised by the industry.**		
Duke Energy	Yes	Duke Energy has long supported the Field Trial of the Balancing Authority ACE Limit (BAAL) and supports its adoption in place of the current CPS2 as proposed in BAL-001-2.
Response: Thank you for your comments.		
Salt River Project	Yes	There is reasonable concern that the large ACE values that the standard permits under certain conditions will cause excessive unscheduled flow on qualified transmission paths. We believe that this issue can be

Organization	Yes or No	Question 2 Comment
		managed by the Reliability Coordinator through enforcement of existing standards, but may require changes to current practices.
Response: Thank you for your comments.		
EnerVision, Inc.	Yes	
Tucson Electric Power Co	Yes	
Energy Mark, Inc.	Yes	
Texas Reliability Entity		1) The Implementation Plan does not include the WECC ATEC term. The ACE equation should be simplified so that it can apply to any interconnection. Any Time Error Correction term or alternate tertiary control term added to the ACE equation should enable any interconnection to control time error and reduce inadvertent interchange. 2) Attachment 2 also needs additional clarification regarding valid/invalid data. If a one-minute frequency sample is determined to not be valid, how is the 30 consecutive clock-minute count affected? Does the invalid minute count as an exceedance, or does the count ignore the invalid minute, or does the count start over at 0? 3) For Requirement R2, does there need to be an exclusion for the 30 consecutive clock-minute average if the BA experiences an EEA event or has a Balancing Contingency event within the 30 minute period? It seems feasible that if a BA experiences an EEA with extended low frequency or a Balancing Contingency event with an extended recovery period, that the clock-minute average for R2 might subsequently fail. Is this the intent of the SDT?

Organization	Yes or No	Question 2 Comment
Response: Thank you for your comments. **1) The SDT has chosen not to include a generic time error correction term in the Reporting ACE equation definition. The SDT has modified the definition to address concerns raised by the industry.** **2) The SDT has added clarifying language to Attachment 2 on how bad data is handled for BAAL.** **3) The SDT discussed this issue in great detail. The SDT decided that it would not be in the best interest of reliability to grant any exceptions.**		
American Electric Power		AEP has suggested modifications regarding scope and content in our responses to Q1 & Q3. Most concerning to us are the topics raised in our response to Q3 (below).
Response: Thank you for your comment. Please refer to our responses above.		
MRO NERC Standards Review Forum		Assuming we are wrong and that the drafting team has authority under their SAR to modify BAL-001, we have the following comments. 1) Unless there is justification we missed, the new definitions should be removed. 2) With regard to the ACE equation and the WECC ATEC term, we recommend that the ACE equation be simplified and made such that it would work with any interconnection. We recommend the term IATEC be changed to ITC, which would stand for Tertiary Control. (Alternatively, clarify that IATEC is equal to ITC. This way the reporting and operating number would be the same.) The balancing standards should limit the magnitude of TC to a value such as 20% of Bias. This would work for both the WECC and HQ approach to controlling time error and assisting in inadvertent interchange management (WECC). It would also give the Eastern Interconnection a tool to reduce the number of Time Error Corrections, which will be important if we want to encourage generators to reduce their dead-bands under BAL-003-1.

Organization	Yes or No	Question 2 Comment
Response: Thank you for your comments. **1 – The SDT believes that the new definitions are needed to provide necessary clarity for the standard.** **2 – The SDT has modified the definition for Reporting ACE based on the collective comments from the industry.**		
ERCOT		ERCOT ISO suggests that the drafting team consider adding the following language to the beginning of Requirement R2: The BAAL measure in R2 is a single event performance measurement similar to BAL-002-2 R1. BAL-002-2 R1 does not apply when a BA is in Emergency Alert Level 2 or 3. During EEA 2 or 3, priority should be given to returning the system to a secure state. Arguably this should exclusion should apply to all emergency conditions (EEA 1, EEA 2, and EEA 3). Consistent with the exclusion in BAL-002-2 R1, ERCOT suggests that the SDT consider adding the language below to BAL-001-2 R2:"'Except when an Energy Emergency Alert Level 2 or Level 3 is in effect' each Balancing Authorty shall operate such that its clock-minute average of Reporting ACE does not exceed its clock-minute Balancing Authority ACE Limit (BAAL) for more than 30 consecutive clock-minutes, as calculated in Attachment 2, for the applicable Interconnection in which the Balancing Authority operates. [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]"ERCOT ISO is voting "no" for the preceding reasons. However, if ERCOT ISO's proposed revisions are adopted, ERCOT ISO would support the standard.
Response: Thank you for your comments. The SDT discussed this issue in great detail. The SDT decided that it would not be in the best interest of reliability to grant any exceptions.		
PPL NERC Registered Affiliates		N/A
Modesto Irrigation District		Need a technical justification for the various Epsilon values specified.

Organization	Yes or No	Question 2 Comment
Response: Thank you for your comment. The Epsilon values were developed during the implementation of CPS1. These values are reviewed under the auspices of the NERC OC annually.		
PacifiCorp		PacifiCorp supports this draft.
Response: Thank you for your comments.		
PJM Interconnection, L.L.C		PJM is, in general, supportive of this standard with the exception noted in comments for question 1.
Response: Thank you for your comments. Please refer to our response to Question 1.		
Powerex Corp.		Powerex believes that the proposed draft standard is deficient in many respects as highlighted by commenters in the previous posting period. Specifically Powerex notes the following concerns in the proposed standard that highlight the inadequacy of the proposed requirements to uphold the reliability of interconnections. If these concerns are not adequately addressed the resultant standard could lead to degradation in reliability.The deficiencies include:1) The proposed standard allows for an entity to be outside of its BAAL limit for 29 minutes and be inside the limit for one minute, which provides a framework that allows an entity to possibly operate outside of the prescribed bounds 95 % of the time. The consequences of allowing such operations has not been adequately addressed by the drafting team, and allowing this standard to move forward with such latitude could lead to reliability issues. 2) The proposed standard does not restrict or limit BAs during periods of high congestion, when unscheduled flow on the entire system is causing reliability issues and/or exceedance of limits. Under the proposed standard the transmission path operators and BAs are forced to deal with unscheduled flows on the system without adequate tools or procedures in place to remedy the reliability events. During the field

Organization	Yes or No	Question 2 Comment
		trial of the proposed standard these issues have been experienced in the WECC, where congestion management of non-Qualified and Qualified paths has created various operating issues for the entities and Reliability Coordinators. The consequences of allowing unlimited use of a transmission system via unlimited unscheduled flows, without better mechanisms to control flows, could lead to reliability events. The proposed standard does not provide the authority to the Reliability Coordinators to control and/or propose new operating procedures (eg. Limiting all BAs in the interconnection to operate within L10 during period of congestion) that mitigate unscheduled flows that are adversely impacting the transmission grid. This needs to be addressed in this proposed standard so that during high congestion periods, regardless of system frequency, BAs bring ACE limits within L10 or some other suitable limitation that decreases the adverse impact.3) The proposed standard puts no limits on ACE during times of normal frequency, which allows BAs to inappropriately “lean” on other generation, or to push excessive amount of energy on to the transmission system. This deficiency allows a BA to obtain energy or push unscheduled energy across the interties during times that can be economically advantageous to the BA without regard to impacts upon neighboring BAs, load serving entities and transmission customers. It is paramount that the current standard, with CPS2, remain in place until such time that the reliability issues associated with the draft standard are resolved.

Response: Thank you for your comments.

1. **The reliability standards should not be viewed in isolation. They work together to achieve operating characteristics that are greater than individual requirements. BAAL only addresses the duration of large ACE deviations, however, at the same time CPS1 prevents a BA from accumulating significant repetitive durations with large ACE deviations by providing a CPS1 score in excess of 800% below passing levels for each minute that the BAAL is exceeded.**
2. **The Standard Drafting Team appreciates your concern with respect to uncertainty associated with the Field Trial Results.**

Organization	Yes or No	Question 2 Comment
However, the BAAL has been under Field Trial since July 2005 on the Eastern Interconnection, January 2010 in ERCOT, March 2010 on the Western Interconnection, and January 2011 in Quebec. Voluntary field trials are only as good as the willingness of the participants. NERC cannot force BAs to participate. The Standard Drafting Team feels that a Field Trial with a duration approaching eight years should be sufficient to evaluate a standard. Concerning the Field Trial on the Western Interconnection, the WECC has chosen to take local responsibility for its evaluation and consequently only shared limited data with NERC. The reports supplied by the WECC have indicated that there are still unknowns associated with the standard, but they have failed to indicate any significant reliability impacts that can be attributed to the BAAL. 3. Managing the tools to control path flows on an interconnection is beyond the scope of the BARC SDT. However, the team did provide a new method for estimating path flows as part of the body of work that was considered during the development of BAAL but was not adopted by the WECC. 4. Unscheduled energy flows that do not cause reliability problems are not reliability issues. These issues should not be resolved by reliability standards that do not address reliability problems. The BAAL Field Trial has provided new information concerning the determination of the contribution of unscheduled energy to transmission reliability. However, the BARC SDT determined that it was beyond their scope to take action to implement changes in standards or procedures to restrict the effects of unscheduled energy flows on transmission loading.		
SMUD		See comment in response #1.
Response: Thank you for your comment. Please refer to our response to Question #1.		
Tacoma Power		Tacoma Power does not support the proposed standard. BAL-001 as proposed moves forward with a control standard that has not yet been fully vetted. Since the RBC field trial began in 2010, with a significant portion of WECC BA participation, results point to noteworthy reliability and market related issues. As the RBC allows larger BAs looser control (i.e. larger ACE values) and wider frequency values, the results include: increased coordinated phase shifter operations, dramatic increase in schedule curtailments due to unscheduled flow, frequency increasing in a negative direction during heavy load hours and positive direction during light load hours, increased manual time error corrections and hours of manual time error corrections and increasing inadvertent

Organization	Yes or No	Question 2 Comment
		accumulations. All of these issues need time to be vetted by the industry and the proposed standard modified accordingly before Tacoma Power would support it.
Response: Thank you for your comments. **The Standard Drafting Team appreciates you concern with respect to uncertainty associated with the Field Trial Results. However, the BAAL has been under Field Trial since July 2005 on the Eastern Interconnection, January 2010 in ERCOT, March 2010 on the Western Interconnection, and January 2011 in Quebec. Voluntary field trials are only as good as the willingness of the participants. NERC cannot force BAs to participate. The Standard Drafting Team feels that a Field Trial with a duration approaching eight years should be sufficient to evaluate a standard. Concerning the Field Trial on the Western Interconnection, the WECC has chosen to take local responsibility for its evaluation and consequently only shared limited data with NERC. The reports supplied by the WECC have indicated that there are still unknowns associated with the standard, but they have failed to indicate any significant reliability impacts that can be attributed to the BAAL.**		
IRC-SRC		Unless there is justification we missed, the new definitions should be removed. With regard to the ACE equation and the WECC ATEC term, we recommend that the ACE equation be simplified and made such that it would work with any interconnection. We recommend the term IATEC be changed to ITC, which would stand for Time Control. The balancing standards should limit the magnitude of TC to a value such as 20% of Bias. This would work for both the WECC and HQ approach to controlling time error and assisting in inadvertent interchange management (WECC). It would also give the Eastern Interconnection a tool to reduce the number of Time Error Corrections, which will be important if we want to encourage generators to reduce their deadbands under BAL-003-1.
Response: Thank you for your comments. **1) SDT believes that the new definitions are needed to provide necessary clarity for the standard.** **2) The SDT has modified the definition for Reporting ACE based on the collective comments from the industry.**		

3. **If you have any other comments on BAL-001-2 that you haven't already mentioned above, please provide them here:**

Summary Consideration: The majority of the commenters provided typographical corrections to the standard and associated documents.

Some commenters stated that using a looser ACE control would result in unscheduled energy flows. The SDT explained that unscheduled energy flows that do not cause reliability problems are not reliability issues. Since these issues are not reliability problems they should not be resolved by a reliability standard. The BAAL Field Trial has provided new information concerning the determination of the contribution of unscheduled energy to transmission reliability. However, the BARC SDT determined that it was beyond their scope to take action to implement changes in standards or procedures to restrict the effects of unscheduled energy flows on transmission loading.

A few commenters felt that the SDT was trying to redefine ACE with the proposed definition of Reporting ACE. The SDT stated that the SDT was not attempting to redefine ACE. The intent was to create a standard term for ACE that was flexible enough to not require development of a regional standard. The SDT has chosen not to include a generic time error correction term in the Reporting ACE equation definition. The SDT has modified the definition to address concerns raised by the industry. In addition, the SDT is proposing to move the definition out of the BAL-001 standard and into the NERC Glossary as they feel it applies to multiple standards.

Organization	Yes or No	Question 3 Comment
Avista	No	Looser AGC control resulting from implementation of BAAL results in unscheduled flow. Increasing unscheduled flow events significantly impact each participant in the energy markets. Schedules are curtailed to accommodate RBC, thus favoring one form of generation over another. In this case, variable resources are given an advantage looser control and other parties are impacted. Although this appears to be an economic issue, any time energy schedules are curtailed for reliability reasons, reliability is negatively affected.

Organization	Yes or No	Question 3 Comment
Response: Thank you for your comments. **Unscheduled energy flows that do not cause reliability problems are not reliability issues. Since these issues are not reliability problems they should not be resolved by a reliability standard. The BAAL Field Trial has provided new information concerning the determination of the contribution of unscheduled energy to transmission reliability. However, the BARC SDT determined that it was beyond their scope to take action to implement changes in standards or procedures to restrict the effects of unscheduled energy flows on transmission loading.**		
City of Tallahassee	No	this is not a yes/no question.
MISO Standards Collaborators	No	
ACES Standards Collaborators	No	
Oklahoma Gas & Electric	No	
Bonneville Power Administration	No	
Salt River Project	No	
PacifiCorp	No	
City of Tallahassee	No	
City of Tallahassee	No	
Manitoba Hydro	Yes	(1) Section D, Compliance, 1.1 - the paraphrased definition of ‘Compliance Enforcement Authority’ from the Rules of Procedure is not the standard language for this section. Is there a reason that the standard CEA language is not being used? (2) Implementation Plan, Regulation Reserve Sharing Group - capitalize the words ‘regulating reserve’ because they appear in

Organization	Yes or No	Question 3 Comment
		the Glossary of Terms. (3) Implementation Plan, Reporting ACE - capitalize 'net actual interchange' and change 'scheduled Interchange' to 'Net Scheduled Interchange'. (4) Implementation Plan - make same changes to definitions in Implementation Plan as suggested in Question 1 of this commenting request. (5) VRF/VSL - capitalize 'bulk electric system' in both the High Risk Requirement and Medium Risk Requirement sections.
Response: Thank you for your comments. **1) The SDT is using language supplied by NERC legal.** **2) The SDT has made the correction that you have identified.** **3) The SDT has made the correction that you have identified.** **4) The SDT has made the correction that you have identified.** **5) The SDT has made the correction that you have identified.**		
MRO NERC Standards Review Forum	Yes	1) The implementation plan does not include any mention of the WECC Automatic Time Error Correction in the definition of Reporting ACE. This deficiency needs corrected as was done in the BAL-001-2 document. The NSRF believes the drafting team provided the correct definition in the BAL-001-2 document and therefore this should not be a significant change to the implementation plan or standard. 2) Additionally, it is not clear how a minute that has bad data should be treated in the determination of a 30 minute period under BAAL. This issue needs to be clarified, especially if the minute with bad data happens to be the first or last minute. The NSRF is not asking for a change to the standard, just a clear

Organization	Yes or No	Question 3 Comment
		statement for the purposes of documenting compliance.
Response: Thank you for your comments. **1) The SDT has made the correction that you have identified.** **2) The SDT has added clarifying language to Attachment 2 to address your concern.**		
Xcel Energy	Yes	1) The implementation plan does not include any mention of the WECC Automatic Time Error Correction in the definition of Reporting ACE. This deficiency needs corrected as was done in the BAL-001-2 document. Xcel Energy believes the drafting team provided the correct definition in the BAL-001-2 document and therefore this should not be a significant change to the implementation plan or standard. 2) Additionally, it is not clear how a minute that has bad data should be treated in the determination of a 30 minute period under BAAL. This issue needs to be clarified, especially if the minute with bad data happens to be the first or last minute. Xcel Energy is not asking for a change to the standard, just a clear statement for the purposes of documenting compliance.
Response: Thank you for your comments. **1) The SDT has made the correction that you have identified.** **2) The SDT has added clarifying language to Attachment 2 to address your concern.**		
SPP Standards Review Group	Yes	Add an ‘s’ to ‘period’ in the 2nd line of 4.1.2 in the Applicability Section. Replace ‘greater’ with ‘more’ in the Moderate, High and Severe VSLs for R2. On Page 7 of the Background Document, in the 4th line of the 3rd

Organization	Yes or No	Question 3 Comment
		paragraph, replace ‘that’ with ‘than’ in front of CPS1.
Response: Thank you for your comments. **The SDT has made the correction in the Applicability Section that you have identified.** **The SDT does not see any difference between using the work “greater” versus “more” and therefore has decided to keep the word greater.** **The SDT has made the correction in the Background Document that you have identified.**		
Duke Energy	Yes	Duke Energy does not support the definition of Reporting ACE as written. We believe that “ACE” should be defined as “The difference between the Balancing Authority’s net actual Interchange and its scheduled Interchange, plus its Frequency Bias obligation, plus any known meter error plus Automatic Time Error Correction (ATEC - If operating in the Western Interconnection and in the ATEC mode)”; followed with the equation shown and the details of the variables. “Reporting ACE” should be defined simply as the “The scan rate values of a Balancing Authority’s ACE”. Though Duke Energy supports the adoption of the BAAL; it’s not clear why all of the other changes to the standard are needed, nor is it clear how these changes respond to FERC directives. We believe that it should be mentioned that the BAAL addresses the FERC directive to develop a standard addressing the large loss of load - the BAAL measure will ensure appropriate response to any event causing the Balancing Authority’s ACE to exceed its BAAL (see comments to BAL-013 for further details). Duke Energy agrees with the proposed change to the BAAL equation to accommodate Time-Error Corrections by placing Scheduled Frequency in the numerator and denominator in place of 60 Hz;

Organization	Yes or No	Question 3 Comment
		however it is not clear why Balancing Authorities under the Field Trial have not yet been afforded the opportunity to incorporate the same change in the BAAL calculation in their tools. Duke Energy would support allowing the Balancing Authorities under the Field Trial to make the appropriate changes in their tools to be consistent with the BAAL equation as proposed, and would support the drafting team updating the tools on the NERC Field Trial website to be consistent with the current BAL-001-2 posted.
Response: Thank you for your comments. **The SDT is not attempting to redefine ACE. The intent was to create a standard term for ACE that was flexible enough to not require development of a regional standard. The SDT has chosen not to include a generic time error correction term in the Reporting ACE equation definition. The SDT has modified the definition to address concerns raised by the industry. In addition, the SDT is proposing to move the definition out of the BAL-001 standard and into the NERC Glossary as they feel it applies to multiple standards.** **The SDT agrees with your comment concerning the field trial. The SDT will look into the concern you have identified.**		
Exelon	Yes	Exelon is basically fine with structure.
Response: Thank you for your comment.		
Idaho Power Company	Yes	I believe that operating under the BAAL does not pose a threat to reliability and could help mitigate variable resource integration provided that BAs do not stress the limits during normal operations. If BAs could be encouraged to follow expected changes in system demand reasonably close during normal conditions then the system could more readily absorb unexpected events. However, I'm not sure how this can be addressed within a standard.

Organization	Yes or No	Question 3 Comment
Response: Thank you for your comments.		
Keen Resources Ltd.	Yes	The Frequency Trigger Limit is set too tight at 3 standard deviations. This causes too many initial exceedences of BAAL as revealed in the field tests. This prompts BAs to wait until enough of them disappear by themselves to make it feasible to address all of the remainder. But, by waiting, the BA is failing to address the remainder early enough before they become outright violations. Instead, it would be better for reliability to raise the Frequency Trigger Limit to, say, 4 or 5 standard deviations to reduce the number of initial exceedences of BAAL to the point where it is feasible to address ALL of them immediately. What reliability is gained by a tighter limit that is feasible only if the BAs wait to address any and all of the exceedences? Furthermore, no legitimate statistical justification was ever provided for the tight 3-standard-deviations Frequency Trigger Limit. The very flawed attempt to provide such a justification led to rejection of the first version of this standard put out for balloting. No further formal technical justification was thereafter developed on which to base that or a wider limit, despite acknowledgement for a time on the drafting team that it was needed.
Response: Thank you for your comments. **The drafting team has considered other alternative approaches and has selected the 3 epsilon model as the best and fairest model for the requirement. BAAL was designed to provide for better control by allowing power flows that do not have a detrimental effect on reliability but restrict those that do have a detrimental effect on reliability.**		
seattle city light	Yes	The Guidelines document purported to address issues such as those discussed in question 2 above will not be available for review until summer 2013. Lacking such a document, Seattle City

Organization	Yes or No	Question 3 Comment
		Light cannot support this draft of BAL-001-2.
Response: Thank you for your comments. **The Guidelines Document is anticipated to be posted by July 19, 2013.**		
NextEra Energy	Yes	The High Frequency Limit (FTLhigh) calculated as Fs + 3Ô□1i should be changed to Fs + 4Ô□1i
Response: Thank you for your comments. **The SDT believes that the High Frequency Limit is calculated properly as currently written in the standard. Without further information as to why you believe it is incorrect, the SDT cannot address your issue.**		
Tucson Electric Power Co	Yes	Using the newly-defined term Reporting (ATEC) ACE is a positive change. Using Scheduled Frequency instead of 60Hz in the BAAL calculation is also a positive change.
Response: Thank you for your comments.		
American Electric Power	Yes	We would encourage the drafting team to provide Generator Operators with the appropriate requirements to support the Balancing Authorities. As currently drafted, the Balancing Authority may be the sole entity responsible for meet the obligations of the standard, and yet it does not have direct control over the Generator Operator to ensure the BA receives what is needed. At the least, the BA might need some sort of recourse specified in the event a Generator Operator is not acting in a cooperative manner (for example, a Generator Operator who refuses to adhere to their agreed-upon schedule in real time, but is not penalized because they integrate over the hour).

Organization	Yes or No	Question 3 Comment
Response: Thank you for your comments. **The SDT understands your concern but believes that it is outside the scope of this project. The SDT believes that this is a commercial issue that should be addressed by FERC.**		
EnerVision, Inc.	Yes	
Energy Mark, Inc.	Yes	
SERC OC Standards Review Group		: We do not believe it is appropriate to include a region or interconnection specific definition in a continent-wide standard. However, we would not object to including a generic term for time-control adjustment.These comments were also supported by Ron Carlsen with Southern Company.The comments expressed herein represent a consensus of the views of the above named members of the SERC OC Standards Review Group only and should not be construed as the position of the SERC Reliability Corporation, or its board or its officers.
Response: Thank you for your comments. **The SDT is only attempting to recognize the approved variance that was granted to the WECC.**		
PPL NERC Registered Affiliates		LGE and KU Services is a participant in the BAAL Field Test and support the implementation of the BAAL standard
Response: Thank you for your comments.		
Portland General Electric Company		PGE is generally supportive of the underlying goal of this standard revision - increased coordination between BAs for efficiently and reliably, meeting Control Performance Standards through the development of a Regulation Reserve Sharing Group, or other yet

Organization	Yes or No	Question 3 Comment
		to be named program. However, PGE is concerned the proposed standard does not adequately address the reliability concerns associated with unscheduled flow and degraded frequency response metrics that have been witnessed with the current WECC Reliability Based Control pilot program. PGE believes the unique physical transmission properties of the Western Interconnect dictate a need for increased consideration of reliability protections for our region prior to the adoption of new nation-wide standards.
Response: Thank you for your comments. **Unscheduled energy flows that do not cause reliability problems are not reliability issues. Since these issues are not reliability problems they should not be resolved by a reliability standard. The BAAL Field Trial has provided new information concerning the determination of the contribution of unscheduled energy to transmission reliability. However, the BARC SDT determined that it was beyond their scope to take action to implement changes in standards or procedures to restrict the effects of unscheduled energy flows on transmission loading.**		
Powerex Corp.		Powerex believes that the reliability issues with the current draft standard have not been adequately addressed by the drafting team. The reliability issues that have been previously submitted by commenters raised valid concerns, and the drafting team has not addressed those specific concerns in their responses. Powerex submits the following subsequent comments: 1) In Order No. 890, the Federal Energy Regulatory Commission (FERC or the Commission) recognized the potential for inadvertent energy flows between adjacent BAs to both jeopardize reliability and to cause undue harm to customers on the grid. Such inadvertent energy flows are driven by the size of each BAAs ACE, but are primarily contained by CPS2 under the current BAL-001. FERC also made it clear that it was inappropriate for generators

Organization	Yes or No	Question 3 Comment
		within a BAA to “dump power on the system or lean on other generation...The tiered imbalance penalties adopted in the Final Rule generally provide a sufficient incentive not to engage is such behavior”The proposed standard will allow entities to create deliberate inadvertent flows within the standards boundaries, without regard to the impacts and which could lead to exceedances in SOL due to large ACEs. The proposed performance standard does not address the potential for a single BA to lean on the grid with deliberate unscheduled energy flows or inadvertent energy, taking any accumulated benefits for itself and harming other entities on the grid. The detrimental impacts of deliberate inadvertent flows to load customers and transmission customers on the grid could be substantial when large ACE deviations cause transmission limit exceedances. It is imperative that the drafting team address this issue in the standard. 2) Various entities have also expressed concerns regarding the reliability impacts of inadvertent or unscheduled flows. The issues experienced by entities during the Field Trial were provided in the previous comment period, but the drafting team has failed to address the comments adequately. Furthermore, the drafting team ignored the concerns and provided a generic response to commenters from NE ISO, WECC, Tucson, APS, BPA and NPPD. These concerns regarding the BAAL standard include comments such as:a. Reliability concerns over BAAL limits not accounting for large ACE excursions b. Increase in transmission limit exceedances c. Interconnection exposed due to the lack of ACE bounding d. CPS 2 is a more reliable metrice. Allows for more unscheduled power flows and amount of unscheduled interchange a BA can have is not cappedf. WECC average frequency deviation has been increasingg. Elimination of CPS2 has a detrimental impact on

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		reliability h. Leads to transmission constraints and requires TOPs and RCs to restrict the unscheduled flows on the system due to a BA unilaterally over or under generatingi. WECC has experienced many SOL violations due to Large ACEs 3) After reviewing the previous comments and responses, it has become abundantly clear that the drafting team chose to respond to commenters with generic statement such as "The drafting team conducts a monthly call to review the results from the BAAL field trial. There have not been any reliability issues raised by any RC during these calls. The drafting team encourages BA's and RC's to share any specific occurrences that they feel have reliability impacts as a result of operating under BAAL.", but did not specifically address, revise or enhance the proposed standard based on the comments.These generic statements are not appropriate by a drafting team and could be considered as dismissive.. The drafting team seems to be suggesting that the "monthly call" mentioned in the drafting team's response is the only forum where reliability concerns need to be addressed. As an example, WECC submitted comments and provided information on RC actions and asked for the drafting team to remedy the issue in the standard, and I quote "During Phase 3, the Reliability Coordinators (RC) reported several SOL exceedance associated with high ACE. The SOL exceedances were mitigated when RCs requested the high ACE value to be reduced to L10.The SDT must address transmission loading issues caused by high ACE."The drafting team did not adequately address this issue, which was raised by a regional entity, and responded by issue a generic statement that since this issue wasn't discussed on the monthly phone call that these issues or experiences in WECC are not true reliability issues. It is imperative that the drafting team revisit all

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		those comments that have been received and make appropriate revisions, and additions to the standard address the reliability concerns raised by the entities regarding SOL exceedance, transmission loading, and unscheduled flow issues. 4) Powerex believes that the current field trial has not proven to be more reliable, and it is imperative that the issues surrounding the increases in frequency error, exceedance of SOL and transmission limits be addressed. There has been no comparison or evidence provided that shows that the proposed standard is superior in reliability than CPS2. Several commenters have raised concerns with the elimination of CPS2, and impacts associated with the increase of frequency error and unscheduled interchange due to large ACE deviations, which pose a greater risk to reliability than the current CPS2 requirement. The drafting team cannot provide a generic statement that “BAAL was designed to provide for better control by allowing power flows that do not have a detrimental effect on reliability but restrict those that do have a detrimental effect on reliability” without providing any evidence or data to test the validity of those statements. The drafting team has not provided any supporting evidence or data that would validate such a generic statement, nor has it provided any benefits that were realized during the field trial and resulted in enhanced reliability. On the contrary, WECC has experienced a degradation of reliability measures, impacts to commercial transmission customers, as well as reliability issues that required RC intervention during the field trial. Those detrimental effects of the proposed standard cannot be offset by the drafting team providing generic and unsupported statements. 5) Powerex believes that the standard should have a BAALHigh and BAALLow in place at all time in order to manage ACE

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		deviations that may jeopardize reliability through unscheduled flows, which can lead to exceedance of SOL and transmission limits. For example, WECC membership found it appropriate to apply a limit of 4 times a BA's L10. This mechanism provides flexibility to handle interconnection frequency while not allowing ACE deviations to become so significant that BA flows negatively impact the transmission system. 6) The drafting team stated in their response to previous comments that "The drafting team will be preparing a report based on the field trial results that will be posted prior to the FERC filing for this draft standard". Powerex poses two questions to the drafting team: a) Why have the field trial results not been provided to NERC membership prior to ballot body? b) Why have the results for the field trial not been updated on the project page on the NERC website since June 2012? 7) The drafting team has not adequately addressed the issue of "sawtoothing" operations as exhibited by entities during the field trial. Sawtoothing can be described as entities that are allowing ACE to be unlimited for 29 minutes and then be brought under BAAL limits for 1 minute. This type of behavior is shown in the NERC reports posted on the field trial. The drafting team is hedging that entities will not operate in this manner after the field trial due to higher operation and compliance risk to entities. However, the NERC field trial should have created disincentives to not allow such behavior during the onset of the field trial, and requirements should have been adopted to discourage behavior that poses reliability risks.

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Response: The SDT thank you for your comments. **Unscheduled energy flows that do not cause reliability problems are not reliability issues. Since these issues are not reliability problems they should not be resolved by a reliability standard. The BAAL Field Trial has provided new information concerning the determination of the contribution of unscheduled energy to transmission reliability. However, the BARC SDT determined that it was beyond their scope to take action to implement changes in standards or procedures to restrict the effects of unscheduled energy flows on transmission loading.** **The BARC SDT was able to determine that BAAL provides a guarantee that if all BAs are operating within their BAAL the interconnection frequency error will remain less than the frequency trigger limit.** **With the change in SDT leadership, some of the field trial data was not getting posted. The data is now posted and the SDT leadership is attempting to post the information on a monthly basis.**		
Tacoma Power		Tacoma Power does not support a standard that institutionalizes a control methodology that is still in the development stage and is not supported by actual data. Thank you for consideration of our comments.
Response: Thank you for your comments. **The SDT does not agree that the requirements in BAL-001-2 are a control methodology.**		
Texas Reliability Entity		The latest changes to the VSLs for R2 made them more confusing. We would suggest re-wording them to state, for example: “The Balancing Authority exceeded its clockâ€minute BAAL for more than 30 consecutive clock minutes and for less than or equal to 45 consecutive clock minutes.”
Response: Thank you for your comments. **The SDT believes that the wording presently used in the VSLs provides the necessary clarity. In addition, your concern that the VSLs are confusing has not been supported by the rest of the industry.**		

END OF REPORT