Consideration of Comments

Project 2007-12 Frequency Response (BAL-003-1)

The Project 2007-12 Drafting Team thanks all commenters who submitted comments on the proposed standard, BAL-003-1 which was posted for a 30-day formal comment period from October 5, 2012 through November 6, 2012. Stakeholders were asked to provide feedback on the standard and associated documents through a special electronic comment form. There were 50 sets of comments, including comments from approximately 144 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 replacing the term "…subject to…: with "…in accordance with…" in Requirement R2.
- Clarified the description of the calculation for the Interconnection IFRO in Attachment A.
- Modified Attachment A and the Procedure to provide consistency with the use of the term "resource contingency criteria".
- Corrected typographical errors in all documents.

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

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

10.	David Kiguel	Hydro One Networks Inc.	NPCC	1
11.	Michael Lombardi	Northeast Utilities	NPCC	1
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 Pedowcz	Northeast Power Coordinating Council	NPCC	10
16.	Wayne Sipperly	New York Power Authority	NPCC	5
17.	Robert Pellegrini	The United Illuminating Company	NPCC	1
18.	Si-Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
19.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
20.	Brian Robinson	Utility Services	NPCC	8
21.	Brian Shanahan	National Grid	NPCC	1
22.	Donald Weaver	New Brunswick System Operator	NPCC	2
23.	Ben Wu	Orange and Rockland Utilities	NPCC	1
24.	Christina Koncz	PSEG Power LLC	NPCC	5

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2.	Group	Erik Ela	NREL Transmission and Grid Integration Group										

	Additional Member	Additional Organization	Region	Segment Selection
1.	Vahan Gevorgian	NREL	NA - Not Applicable	NA
2.	Brendan Kirby	Consultant	NA - Not Applicable	NA
3.	Yingchen Zhang	NREL	NA - Not Applicable	
4.	Mohit Singh	NREL	NA - Not Applicable	

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3.	Group	WILL SMITH	MRO NSRF	X	X	X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	MAHMOOD SAFI	OPPD	MRO	1, 3, 5, 6
2.	CHUCK LAWRENCE	ATC	MRO	1
3.	TOM BREENE	WPS	MRO	3, 4, 5, 6
4.	JODI JENSON	WAPA	MRO	1, 6
5.	KEN GOLDSMITH	ALTW	MRO	4
6.	ALICE IRELAND	XCEL	MRO	1, 3, 5, 6
7.	DAVE RUDOLPH	BEPC	MRO	1, 3, 5, 6

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

8.	ERIC RUSKAMP	LES	MRO	1, 3, 5, 6
9.	JOE DEPOORTER	MGE	MRO	3, 4, 5, 6
10.	SCOTT NICKELS	RPU	MRO	4
11.	TERRY HARBOUR	MEC	MRO	5, 6, 1, 3
12.	MARIE KNOX	MISO	MRO	2
13.	LEE KITTELSON	OTP	MRO	1, 3, 5
14.	SCOTT BOS	MPW	MRO	1, 3, 5, 6
15.	TONY EDDLEMAN	NPPD	MRO	1, 3, 5
16.	MIKE BRYTOWSKI	GRE	MRO	1, 3, 5, 6
17.	DAN INMAN	MPC		1, 3, 5, 6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4.	Group	Chris Higgins	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Bart McManus	Technical Operations	WECC	1
2.	Kristy Humphrey	Technical Operations	WECC	1
3.	Ayodele Idowu	Technical Operations	WECC	1
4.	Rebecca Berdahl	Policy Development & Analysis	WECC	3

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
5.	Group	Scott Miller	MEAG Power	X		X		X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Steve Jackson	MEAG Power	SERC	3
2.	Danny Dees	MEAG Power	SERC	1
3.	Steve Grego	MEAG Power	SERC	5

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

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

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
5.			NPCC	6
6.			SERC	6
7.			SPP	6
8.			RFC	6
9.			WECC	6
10.	Brent Ingebrigtson	LG&E and KU Services	SERC	3

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

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8.	Group	Jason Marshall	ACES Power Marketing Standards Collaborators						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Shaver	Arizona Electric Power Cooperative/Southwest Transmission Cooperative, Inc.	WECC	1, 4, 5
2.	Bill Hutchison	Southern Illinois Power Cooperative	SERC	1
3.	Megan Wagner	Sunflower Electric Power Corporation	SPP	1

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9.	Group	Gerry Beckerle	SERC OC Standards Review Group	X		X							

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jeff Harrison	AECI	SERC	1, 3, 5, 6
2.	Robert Thomasson	Big Rivers Electric Corp.	SERC	1
3.	Dan Roethemeyer	Dynegy	SERC	5
4.	Adam Guinn	Duke Energy	SERC	1, 3, 5, 6
5.	Brad Young	LGE-KU	SERC	1, 3, 5, 6
6.	Wayne Van Liere	LGE-KU	SERC	1, 3, 5, 6
7.	Marie Knox	MISO	SERC	2
8.	Terry Bilke	MISO	SERC	2

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

9.	Troy Blalock	SCE&G	SERC	1, 3, 5, 6
10.	Cindy Martin	Southern Co. Services	SERC	1, 5
11.	Todd Lucas	Southern Co. Services	SERC	1, 5
12.	Kelly Casteel	TVA	SERC	6, 1, 3, 5
13.	Joel Wise	TVA	SERC	1, 3, 5, 6
14.	Stuart Goza	TVA	SERC	1, 3, 5, 6
15.	Steve Corbin	SERC Reliability Corp	SERC	10

				1	2	3	4	5	6	7	8	9	10
10.	Group	David Dockery, NERC Reliability Compliance Coordinator	Associated Electric Cooperative, Inc. - JRO00088	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Central Electric Power Cooperative		SERC	1, 3
2.	KAMO Electric Cooperative		SERC	1, 3
3.	M & A Electric Power Cooperative		SERC	1, 3
4.	Northeast Missouri Electric Power Cooperative		SERC	1, 3
5.	N.W. Electric Power Cooperative, Inc.		SERC	1, 3
6.	Sho-Me Power Electric Cooperative		SERC	1, 3

				1	2	3	4	5	6	7	8	9	10
11.	Group	Scott Kinney	Avista	X		X		X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Scott	Kinney	WECC	1
2.	Bob	Lafferty	WECC	3
3.	Ed	Groce	WECC	5

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Allen	City Utililties of Springfield	SPP	1, 4
2.	Lisa Duffey	Cleco Power	SPP	1, 3, 5
3.	Tiffany Lake	Westar Energy	SPP	1, 3, 5, 6
4.	Greg McAuley	Oklahoma Gas & Electric	SPP	1, 3, 5
5.	Stephen McGie	City of Coffeyville	SPP	NA

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

6.	Terry Petzoldt	Kansas City Board of Public Utilities	SPP	3
7.	Valerie Pinamonti	American Electric Power	SPP	1, 3, 5
8.	Randy Root	Grand River Dam Authority	SPP	1, 3, 5
9.	Katie Shea	Westar Energy	SPP	1, 3, 5, 6
10.	Bryan Taggart	Westar Energy	SPP	1, 3, 5, 6

13.	Group	Thomas McElhinney	JEA	X		X		X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ted Hobson		FRCC	1
2.	Garry Baker		FRCC	3
3.	John Babik		FRCC	5

14.	Individual	Mark Gray	Edison Electric Institute	X		X		X	X				
15.	Individual	Janet Smith, Regulatory Affairs Supervisor	Arizona Public Service Company	X		X		X	X				
16.	Individual	ryan millard	pacificorp	X		X		X	X				
17.	Individual	Stephanie Monzon	PJM Interconnection, LLC		X								
18.	Individual	Richard Vine	California Independent System Operator		X								
19.	Individual	Howard F. Illian	Energy Mark, Inc.								X		
20.	Individual	Thad Ness	American Electric Power	X		X		X	X				
21.	Individual	Jonathan Appelbaum	The United Illuminating Company	X									
22.	Individual	Travis Metcalfe	Tacoma Power	X		X	X	X	X				
23.	Individual	Nazra Gladu	Manitoba Hydro	X		X		X	X				
24.	Individual	Alice Ireland	Xcel Energy	X		X		X	X				
25.	Individual	Shammara Hasty	Southern Company	X		X		X	X				
26.	Individual	Greg Travis	Idaho Power Company	X		X							
27.	Individual	John Seelke	Public Service Enterprise Group	X		X		X	X				
28.	Individual	Michael Falvo	Independent Electricity System Operator		X								
29.	Individual	Brian J Murphy	NextEra Energy	X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
30.	Individual	Don Jones	Texas Reliability Entity										X
31.	Individual	Don Schmit	Nebraska Public Power District	X		X		X					
32.	Individual	Brett Holland	Kansas City Power & Light	X		X		X	X				
33.	Individual	Angela P Gaines	Portland General Electric Company	X		X		X	X				
34.	Individual	Kathleen Goodman	ISO New England Inc.		X								
35.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				
36.	Individual	Oliver Burke	Entergy Services, Inc. (Transmission)	X									
37.	Individual	Chris de Graffenried	Consolidated Edison Co. of NY, Inc.	X		X		X	X				
38.	Individual	David Jendras	Ameren	X		X		X	X				
39.	Individual	Maggy Powell	Exelon Corporation and its affiliates	X		X	X	X	X				
40.	Individual	Janelle Marriott Gill	Tri-State Generation and Transmission Assn., Inc.	X		X		X					
41.	Individual	Denise M Lietz	Puget Sound Energy	X		X		X					
42.	Individual	Rich Salgo	NV Energy	X		X		X					
43.	Individual	John Tolo	Tucson Electric Power	X									
44.	Individual	Ken Gardner	AESO		X								
45.	Individual	Patricia Robertson	BC Hydro	X	X	X		X					
46.	Individual	Grergory Campoli	New York Independent System Operator		X								
47.	Individual	Robert Blohm	Keen Resources Asia Ltd.								X		
48.	Individual	Marie Knox	MISO		X								
49.	Individual	Tony Kroskey	Brazos Electric Power Cooperative, Inc.	X									
50.	Individual	Mauricio Guardado	Los Angeles Department of Water and Power	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"
MEAG Power	Southern Company Services, Inc - Gen
Associated Electric Cooperative, Inc. - JRO00088	SERC OC Standards Review Group
Avista	Bonneville Power Administration
Nebraska Public Power District	MRO NSRF [Midwest Reliability Organization - NERC Standards Review Forum]
ISO New England Inc.	Last submitted comments of ISO-NE which have not been addressed and, for efficiency sake, do not believe we should be requested to re-submit.
South Carolina Electric and Gas	SERC OC Standards Review Group
Entergy Services, Inc. (Transmission)	Entergy is in agreement with comments submitted by SERC on 11/5/0212.
Brazos Electric Power Cooperative, Inc.	ACES Power Marketing

1. **The SDT has made minor modifications to the proposed definition for Frequency Response Measure based on industry comments. Do you agree that these modifications provide sufficient clarity? If not, please explain in the comment area.**

Summary Consideration: A few of the commenters felt that the definition applied to all of the observations for both the BA and the FRSG. The drafting team stated that although they understood their concern they did not agree with them. They felt that the present definition provided sufficient clarity and decided to not make any modifications.

One commenter felt that the definition should state that it is a negative value. The drafting team explained that while the desired value would be negative it is mathematically feasible for the actual value to be positive but that value would by definition mean that the entity failed the measurement for Requirement R1.

Another commenter did not believe that there was sufficient clarity as to the number of observations that would be used to calculate FRM. The drafting team stated that the number of observations would vary from year to year. The basis for determining events is outlined in the Procedure attached to this standard.

Organization	Yes or No	Question 1 Comment
Duke Energy	No	The definition reads as if the FRM is the median of all of the observations reported by the Balancing Authorities and Frequency Response Sharing Groups. Duke Energy would suggest that the definition read, “The median of all of the Frequency Response observations reported annually by a Frequency Response Sharing Group, or Balancing Authority if not a participant in a Frequency Response Sharing Group, for frequency events specified by the ERO. The Frequency Response Measure is calculated as MW/0.1Hz.”
Response: The drafting team thanks you for your comment. However, the drafting team believes that the present definition provides sufficient clarity and has decided to not make any changes.		
SERC OC Standards Review Group	No	The definition reads as if the FRM is the median of all of the observations reported by the Balancing Authorities and Frequency Response Sharing Groups. We agree with the Duke Energy suggestion that the definition read, “The median of all of the Frequency Response observations reported annually by a Frequency Response Sharing Group, or Balancing

Organization	Yes or No	Question 1 Comment
		Authority if not a participant in a Frequency Response Sharing Group, for frequency events specified by the ERO. The Frequency Response Measure is calculated as MW/0.1Hz."
Response: The drafting team thanks you for your comment. However, the drafting team believes that the present definition provides sufficient clarity and has decided to not make any changes.		
PPL NERC Registered Affiliates	No	The PPL Affiliates support the comments of the SERC OC Standards Review Group on this question.
Response: The drafting team thanks you for your comment. However, the drafting team believes that the present definition provides sufficient clarity and has decided to not make any changes.		
BC Hydro	Yes	Additionally, there should be language to clarify that this is a negative value (the same should apply to the definitions of FRO and Frequency Bias). It is fairly obvious that these values should be negative when reading elsewhere in the proposed Standard and its related document but not in their definitions.
Response: While the desired value would be negative it is mathematically feasible for the actual value to be positive but that value would by definition mean that the entity failed the measurement for Requirement R1.		
Tucson Electric Power	Yes	however, the number of observations to be used in calculating an entity's FRM is not clear.
Response: Thank you for your affirmative response and clarifying comment. The number of observations will vary from year to year. The basis for determining events is outlined in the Procedure attached to this standard.		
Exelon Corporation and its affiliates	Yes	Please see response to question 8. The FRM definition is acceptable within the context of the attachment description; however, without clarifying the terms under which the ERO specifies which events are to be measured, the FRM definition is too variable.
Response: Thank you for your affirmative response and clarifying comment. The criteria used to determine the events to be used are outlined in the Procedure attached to this standard. Please refer to our response to Question #8.		

Organization	Yes or No	Question 1 Comment
ACES Power Marketing Standards Collaborators	Yes	We believe that refinements to the definition were needed.
Response: Thank you for your affirmative response and clarifying comment.		
Manitoba Hydro	Yes	No comment.
Northeast Power Coordinating Council	Yes	
NREL Transmission and Grid Integration Group	Yes	
MRO NSRF	Yes	
Bonneville Power Administration	Yes	
SPP Standards REview Group	Yes	
Edison Electric Institute	Yes	
Arizona Public Service Company	Yes	
pacificorp	Yes	
PJM Interconnection, LLC	Yes	
California Independent	Yes	

Organization	Yes or No	Question 1 Comment
System Operator		
Energy Mark, Inc.	Yes	
Tacoma Power	Yes	
Xcel Energy	Yes	
Southern Company	Yes	
Idaho Power Company	Yes	
Independent Electricity System Operator	Yes	
Texas Reliability Entity	Yes	
Kansas City Power & Light	Yes	
Consolidated Edison Co. of NY, Inc.	Yes	
Ameren	Yes	
NV Energy	Yes	
New York Independent System Operator	Yes	
Keen Resources Asia Ltd.	Yes	

Organization	Yes or No	Question 1 Comment
MISO	Yes	
American Electric Power		As provided in question 2 below, AEP does not agree with the definition containing the Frequency Response Sharing Group as this function does not exist at this point in time.
Response: Thank you for your comments. The term Frequency Response Sharing Group is defined at the beginning of the standard. Once this standard is approved by the industry, NERC BOT and FERC the definition will be removed from the standard and added to the NERC Glossary of Terms.		

2. **The SDT has created a definition for Frequency Response Sharing Group. The definition is as follows: A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the Frequency Response Obligations of its members. Do you agree with this definition? If not, please explain in the comment area.**

Summary Consideration: Almost all of the commenters wanted to modify the definition. The drafting team explained that they believed that the proposed definition should remain unchanged. The drafting team developed the definition to be essentially the same as that currently used for contingency Reserve Sharing Groups. This will help ensure that the different types of reserve groups are comparable as we move forward with this new type of group.

One commenter did not agree believe it was appropriate to define a new function that was not in the NERC ROP, NERC Statement of Registry Criteria or the NERC Functional Model. The drafting team stated that they had discussed this issue with NERC. NERC staff will add this entity to the registered entity list in the same manner as the existing Reserve Sharing Group. While this is not in the current version available online, NERC will have at least 24 months from the time of regulatory approval to add the entity to the list of registered entities.

Organization	Yes or No	Question 2 Comment
SERC OC Standards Review Group	No	A Balancing Authority may not be the entity maintaining or supplying resources, but would be responsible for utilizing applicable resources within its BA Area. We would modify the Duke Energy suggestion to read as follows: "A group whose members consist of two or more Balancing Authorities that collectively utilize operating resources with a goal to achieve a group FRM equal to or more negative than the sum of the Frequency Response Obligations of its members."
Response: Thank you for your comments. After review of suggested changes, the drafting team believes that the proposed definition should remain unchanged. The drafting team developed the definition to be essentially the same as that currently used for contingency Reserve Sharing Groups. This will help ensure that the different types of reserve groups are comparable as we move forward with this new type of group.		
American Electric Power	No	AEP does not necessarily disagree with the words of the definition. However, AEP does

Organization	Yes or No	Question 2 Comment
		not believe it is appropriate to define a new function that is not in the NERC Rules of Procedure, NERC Statement of Registry Criteria, or the NERC Functional Model. It is premature to incorporate this entity without a proposed change to these governing NERC documents.
Response: Thank you for your comments. The drafting team has discussed this issue with NERC. NERC staff will add this entity to the registered entity list in the same manner as the existing Reserve Sharing Group. While not in the current version available online, NERC will have at least 24 months from the time of regulatory approval to add the entity to the list of registered entities.		
Duke Energy	No	As a Balancing Authority may not be the entity maintaining or supplying resources, but would be responsible for utilizing applicable resources within its BA Area, Duke Energy would suggest the following definition, “A group whose members consist of two or more Balancing Authorities that collectively utilize operating resources required to achieve a group FRM equal to or more negative than the sum of the Frequency Response Obligations of its members.”
Response: Thank you for your comments. After review of suggested changes, the drafting team believes that the proposed definition should remain unchanged. The drafting team developed the definition to be essentially the same as that currently used for contingency Reserve Sharing Groups. This will help ensure that the different types of reserve groups are comparable as we move forward with this new type of group.		
Edison Electric Institute	No	EEI does not fully agree with the definition of a “Frequency Response Sharing Group” (FRSG). In the definition offered in the new Standard, it states that the FRSG “collectively maintain, allocate, and supply operating resources”. Of the three roles, a balancing authority only maintains load-interchange-generation balance through the allocation of resources. Therefore, EEI suggests that the definition be changed to more appropriately align with the role of a BA, which we believe would be to allocate resources in a manner that effectively allows the sharing of resources necessary to achieve a FRO within the defined sharing group, which might otherwise not be possible or practical by a BA on its own.
Response: After review of suggested changes, the drafting team believes that the proposed definition should remain unchanged. The drafting team developed the definition to be essentially the same as that currently used for contingency Reserve Sharing Groups. This		

Organization	Yes or No	Question 2 Comment
will help ensure that the different types of reserve groups are comparable as we move forward with this new type of group.		
ACES Power Marketing Standards Collaborators	No	We agree that a definition is needed and thank the drafting team for writing one. However, we believe additional refinement of the definition is necessary. Although the definition appears to be written to parallel the Reserve Sharing Group definition, we think the definition needs to be simplified. For one, it encompasses actions that are not necessary. For instance, the proposed definition includes the action to “maintain operating resources”. This could literally include generating plant maintenance. We do not agree that a Frequency Response Sharing Group would jointly perform maintenance on their plants. In fact, since the definition applies to BAs, it is entirely possible within the functional model that the BAs do not even own the plants and could not perform joint maintenance. We assume the purpose of including “maintain” was to recognize that maintenance of generating resources would need to be coordinated to ensure that there was sufficient frequency response reserve. We do not believe this needs to be explicitly identified in the definition. Furthermore, we find the use of “operating resource” as a source of potential confusion. While we understand operating resource is intended to mean a facility that provides the ability to increase or decrease MW output based on the frequency deviation, resource has various meanings throughout the standards and its use here could be confusing and contradictory. For instance, TOP-006-2 R1 discusses transmission resources. Furthermore, if an “operating resource” is capable of increasingor decreasing MW output based on frequency deviation, what is a “resource”? In other words, why is “operating” added to the term “resource”? We think it is best to avoid use of the term operating resource and, thus, recommend changing the definition to: “A group of two or more Balancing Authorities that share frequency response reserves and are required to jointly meet the Frequency Response Obligations of its members.”
Response: After review of suggested changes, the drafting team believes that the proposed definition should remain unchanged. The drafting team developed the definition to be essentially the same as that currently used for contingency Reserve Sharing Groups. This will help ensure that the different types of reserve groups are comparable as we move forward with this new type of group.		
BC Hydro	Yes	Additionally, there should be language to clarify that the BAs must belong to the same

Organization	Yes or No	Question 2 Comment
		Interconnections to form the FRSG
Response: After review of suggested changes, the drafting team believes that the proposed definition should remain unchanged. The drafting team developed the definition to be essentially the same as that currently used for contingency Reserve Sharing Groups. This will help ensure that the different types of reserve groups are comparable as we move forward with this new type of group.		
PPL NERC Registered Affiliates	Yes	PPL Affiliates suggest additional detail be added to the definition to ensure the members of the FRSG are all within the same interconnection. The following definition includes the suggested changes: A group whose members consist of two or more Balancing Authorities all within a single interconnection that collectively operate resources required to jointly meet the sum of the Frequency Response Obligations of its members.
Response: After review of suggested changes, the drafting team believes that the proposed definition should remain unchanged. The drafting team developed the definition to be essentially the same as that currently used for contingency Reserve Sharing Groups. This will help ensure that the different types of reserve groups are comparable as we move forward with this new type of group.		
Ameren	Yes	The word "jointly" may add confusion and we believe it is unessassry.
Response: After review of suggested changes, the drafting team believes that the proposed definition should remain unchanged. The drafting team developed the definition to be essentially the same as that currently used for contingency Reserve Sharing Groups. This will help ensure that the different types of reserve groups are comparable as we move forward with this new type of group.		
Manitoba Hydro	Yes	No comment.
Northeast Power Coordinating Council	Yes	
NREL Transmission and Grid Integration Group	Yes	
MRO NSRF	Yes	
Bonneville Power	Yes	

Organization	Yes or No	Question 2 Comment
Administration		
SPP Standards REview Group	Yes	
Arizona Public Service Company	Yes	
pacificorp	Yes	
PJM Interconnection, LLC	Yes	
California Independent System Operator	Yes	
Energy Mark, Inc.	Yes	
Tacoma Power	Yes	
Xcel Energy	Yes	
Southern Company	Yes	
Idaho Power Company	Yes	
Texas Reliability Entity	Yes	
Kansas City Power & Light	Yes	
Consolidated Edison Co. of NY, Inc.	Yes	

Organization	Yes or No	Question 2 Comment
Exelon Corporation and its affiliates	Yes	
NV Energy	Yes	
Tucson Electric Power	Yes	
Keen Resources Asia Ltd.	Yes	
MISO	Yes	
Independent Electricity System Operator		Not Applicable

3. **The SDT has added Requirement R3 for entities using variable Frequency Bias. R3. Each Balancing Authority that is a member of a multiple Balancing Authority Interconnection, is not receiving Overlap Regulation Service and utilizing a variable Frequency Bias Setting shall maintain a Frequency Bias Setting that is:**

    3.1 Less than zero at all times, and

    3.3 Equal to or more negative than its Frequency Response Obligation when Frequency varies from 60 Hz by more than +/-0.036 Hz.

Summary Consideration: A couple of commenters felt that the intent of the requirement needed to be clarified. The drafting team explained that Requirement R3 is only applicable to a BA using a variable bias and does require a BA to maintain a bias less than zero. Bullet R3.2 extends the requirement to ensure that BAs using variable bias have a bias at least equal to the FRO when frequency is outside the bandwidth of +/- 0.036 Hz. The BAs using a fixed bias are addressed in Requirement R2.

A few commenters expressed concern with excluding a single BA interconnection from compliance with Requirement R3. The drafting team stated that they had discussed the applicability of variable bias requirements to single BA Interconnections extensively. The consensus of the drafting team was that single BA Interconnections inherently have strong incentives to accurately represent their frequency response characteristic. Any adverse consequences of misrepresenting the frequency response characteristic will be borne solely by that BA and cannot affect other BAs in other Interconnections adversely.

One commenter disagreed with allowing the use of variable Frequency Bias in a multi-BA interconnection. The drafting team believes that this concern may be better addressed within BAL-001. Variable frequency bias settings allow a Balancing Authority to better match their frequency bias setting in use with the actual frequency response occurring at any instant in time. If it is meeting its FRO for larger frequency deviations and the frequency bias setting in use at that time meets or exceeds its FRO, then the BA is doing its part to support frequency and AGC will not be withdrawing that frequency response.

Another commenter question the periodicity of a BA changing its Frequency Bias Setting to be considered using variable Frequency Bias. They gave an example of an entity changing its FBS monthly. The drafting team stated that they had not defined the periodicity for changing their bias to be variable. The example given would be a form of variable bias and would trigger all rules related to variable bias. Requirement R3 is separate from Requirement R4. Requirement R4 is related

to those entities providing Overlap Regulation Service. It is possible for an entity to provide Overlap Regulation Service and have a variable bias setting therefore an entity may be subject to compliance for both Requirement R3 and Requirement R4.

Organization	Yes or No	Question 3 Comment
American Electric Power	No	AEP believes this question in the comment form is incorrect. It appears that R3 and R4 are inadvertently merged together.
Response: The drafting team is not sure of the point you are trying to make. The question only contains the Requirement R3 from the standard. The drafting team did notice that the numbering of the sub-bullets was incorrect.		
Duke Energy	No	Duke Energy agrees with allowing single-BA Interconnections to utilize a variable Frequency Bias Setting (FBS). Duke Energy disagrees with NERC allowing Balancing Authorities in a multiple-BA Interconnection to change the ACE and bounds by which the Balancing Authorities are measured under BAL-001 and BAL-002 by operating to a variable FBS. It is desired that a Balancing Authority be capable of recognizing the amount of primary response available in real-time operation, such information can be included among other information in the generation control algorithm; however, the obligation to support the Interconnection frequency under the secondary control standards, and the amount provided for any given frequency, should be based on the same criteria across all Balancing Authorities of the same size. Nathan Cohn in his comments on Union Electric's use of a variable FBS expressed similar concern regarding the equitable sharing of the obligation to support Interconnection frequency in a multiple-BA Interconnection. Take for example two Balancing Authorities with equal total generation and load, but one operating under a fixed FBS and the other operating under a variable FBS. To the extent that a Balancing Authority is not providing Frequency Response comparable to its fixed Frequency Bias Setting, its ACE will reflect the difference to be covered with secondary control and the Balancing Authority will be measured in a manner similar to other BAs of its "size" based upon the FBS. To the extent that the other BA using a variable FBS is not providing Frequency Response

Organization	Yes or No	Question 3 Comment
		comparable to what it would be allocated using a fixed FBS, its ACE will not reflect the difference or any further obligation to support Interconnection frequency at that time with secondary control. Duke Energy's concern regarding non-comparable treatment of all BAs is further amplified by the lack of scrutiny placed on the BA algorithm used to determine the real-time variable FBS, to ensure that compliance cannot be gamed by such use.
Response: The drafting team believes that this concern may be better addressed within BAL-001. Variable frequency bias settings allow a Balancing Authority to better match their frequency bias setting in use with the actual frequency response occurring at any instant in time. If it is meeting its FRO for larger frequency deviations and the frequency bias setting in use at that time meets or exceeds its FRO, then the BA is doing its part to support frequency and AGC will not be withdrawing that frequency response.		
Northeast Power Coordinating Council	No	If a BA is using a frequency bias setting and is not providing Overlap Regulation Service (supplying actual interchange, frequency response, and schedules to another BA), then it can be assumed that the BA is supplying regulation service. Was the intent of the requirement to simply state that all BA's must have a bias setting less than zero at all times? The intent of this requirement needs to be clarified.
Response: The drafting team is not sure if we understand your first comment. A BA not providing Overlap Regulation Service may or may not be providing Supplemental Regulation Service. Requirement R3 is only applicable to a BA using a variable bias and does require a BA to maintain a bias less than zero. Bullet R3.2 extends the requirement to ensure that BAs using variable bias have a bias at least equal to the FRO when frequency is outside the bandwidth of +/- 0.036 Hz. The BAs using a fixed bias are addressed in Requirement R2.		
Consolidated Edison Co. of NY, Inc.	No	If a BA is using a frequency bias setting and is not providing Overlap Regulation Service (supplying actual interchange, frequency response, and schedules to another BA), then we can assume it is supplying regulation service. Was the intent of the requirement to simply state that all BA's must have a bias setting less than zero at all times? Please clarify the intent of this requirement.
Response: The drafting team is not sure if we understand your first comment. A BA not providing Overlap Regulation Service may or may not be providing Supplemental Regulation Service. Requirement R3 is only applicable to a BA using a variable bias and		

Organization	Yes or No	Question 3 Comment
does require a BA to maintain a bias less than zero. Bullet R3.2 extends the requirement to ensure that BAs using variable bias have a bias at least equal to the FRO when frequency is outside the bandwidth of +/- 0.036 Hz. The BAs using a fixed bias are addressed in Requirement R2.		
Exelon Corporation and its affiliates	No	Please see response to question 8.
Response: Please refer to the drafting team response to Question #8.		
MRO NSRF	No	The MRO NSRF is concerned with the drafting team's exclusion of single Balancing Authority Interconnections from compliance with Requirement R3. To ensure a consistent approach in the application of the standard, recommend R3 be revised as follows:(R3). Each Balancing Authority that is not receiving Overlap Regulation Service and is utilizing a variable Frequency Bias Setting shall maintain a Frequency Bias Setting that is: ...
Response: The drafting team discussed the applicability of variable bias requirements to single BA Interconnections extensively. The consensus of the drafting team was that single BA Interconnections inherently have strong incentives to accurately represent their frequency response characteristic. Any adverse consequences of misrepresenting the frequency response characteristic will be borne solely by that BA and cannot affect other BAs in other Interconnections adversely.		
MISO	No	We agree with the general obligation but believe that the requirement should apply to single BA Interconnections as well. This is supposed to be a North American standard. What other standards shouldn't apply to a single BA Interconnection? We have the same concern with Requirement 2.
Response: The drafting team discussed the applicability of variable bias requirements to single BA Interconnections extensively. The consensus of the drafting team was that single BA Interconnections inherently have strong incentives to accurately represent their frequency response characteristic. Any adverse consequences of misrepresenting the frequency response characteristic will be borne solely by that BA and cannot affect other BAs in other Interconnections adversely.		
PJM Interconnection, LLC	No	With what periodicity does a BA's frequency bias setting have to change to be

Organization	Yes or No	Question 3 Comment
		considered variable bias? For example, if a BA changes it's frequency bias setting monthly based on a percentage of each month's forecast or historic load, is this considered variable bias subject to compliance with R3 in lieu of R4?
Response: The drafting team has not defined the periodicity for changing their bias to be variable. The example given would be a form of variable bias and would trigger all rules related to variable bias. Requirement R3 is separate from Requirement R4. Requirement R4 is related to those entities providing Overlap Regulation Service. It is possible for an entity to provide Overlap Regulation Service and have a variable bias setting therefore an entity may be subject to compliance for both Requirement R3 and Requirement R4.		
BC Hydro	Yes	BC Hydro applauds the STD's efforts to recognize a more suitable bound for Variable Frequency Bias settings
Response: Thank you for your affirmative response and clarifying comment.		
Bonneville Power Administration	Yes	BPA is responding to 3.1 and 3.2 of R3. The bullets listed in question 3 on the original comment form appear to be for Requirement R4. BPA is in support of R3.1 and R3.2.
Response: Thank you for your affirmative response and clarifying comment.		
Texas Reliability Entity	Yes	It appears that R3.2 is based on the assumption that governor dead-band settings are 0.036 Hz for all interconnections with multiple BAs. While the ERCOT region has a standard 0.036 Hz dead-band specified in the ERCOT Protocols and Operating Guides, we are not sure if this is applicable to the other regions.
Response: Thank you for your affirmative response and clarifying comment. In addition, as to the deadband setting, this number was also considered to be within the frequency deviation range of the event determination criteria as defined in the Procedure document.		
Tucson Electric Power	Yes	N/A

Organization	Yes or No	Question 3 Comment
Manitoba Hydro	Yes	No comment.
NREL Transmission and Grid Integration Group	Yes	
ACES Power Marketing Standards Collaborators	Yes	
SPP Standards REview Group	Yes	
Edison Electric Institute	Yes	
pacificorp	Yes	
California Independent System Operator	Yes	
Energy Mark, Inc.	Yes	
Tacoma Power	Yes	
Southern Company	Yes	
Idaho Power Company	Yes	
Kansas City Power & Light	Yes	
Ameren	Yes	
NV Energy	Yes	

Organization	Yes or No	Question 3 Comment
Keen Resources Asia Ltd.	Yes	
Independent Electricity System Operator		Not Applicable

4. **Based on Industry comments the SDT has modified "Attachment A- Supporting Document" to provide additional clarity. Do you agree with the modifications? If not, what modifications do you disagree with?**

Summary Consideration: A few commenters felt that there were requirements stated within Attachment A. The drafting team explained that the requirement stated in the standard was the only requirement related to FRM. Attachment A is there to provide uniformity in the calculation of the FRM. The drafting team conscientiously included only reliability objectives in the requirements and put procedural steps in the attachment and procedure.

Several commenters expressed concern over the use of the largest event in the last 10 years for the Eastern Interconnection while all of the other Interconnections used the Category C (N-2). The drafting team stated that the results for the current Eastern Interconnection model do not represent observed response adequately. The models for the other Interconnections have a better match. For this reason the drafting team has recommended the largest event in the last ten years be used to provide for an increased reliability margin for the Eastern Interconnection. Further details are provided on pages 52 through 55 of the Frequency Response Initiative paper.

A couple of commenters questioned the difference between the present frequency bias of -6,360 MW/0.1 Hz and the proposed of -1,002 MW/0.1 Hz. The drafting team explained that the -6,630 MW/0.1 Hz represents a summation of the Frequency Bias Settings of all Balancing Authorities in the Eastern Interconnection, most of which use the 1% default minimum as required in the current BAL-003-0 standard, which far exceeds their real response. The IFRO of -1002 MW/0.1 Hz is the response determined to avoid the first step of Underfrequency load shedding in the Interconnection for a 4,500 MW generation loss.

A few commenters felt that clarification was need concerning changes in a BAs footprint and changes to the bias setting or FRO. The drafting team felt that this was a problem that would take care of itself. If two BAs change footprint but do not raise the issue the impact is transparent to the Interconnection. If one BA believes that its limits need to be adjusted the process will adjust the limits of both BAs accordingly.

A couple of commenters requested clarity as to how changes to the process in Attachment A would be handled. The drafting team explained that any change to the methodology described in Attachment A would have to go through the Standards Development Process prior to being implemented.

Two commenters felt that there should be an exemption for non-conforming load performing contrary to the performance of conventional load. The drafting team stated that they did not agree that there should be an exemption but has designed the forms to allow for adjustments for non-conforming load. However the BA may find that no adjustment for non-conforming load may be needed due to the measurement over multiple events rather than individual events.

Organization	Yes or No	Question 4 Comment
ACES Power Marketing Standards Collaborators	No	**(1)** Frequency Response Obligation (FRO) is used inconsistently with the proposed definition in the document. The document uses the term “Interconnection Frequency Response Obligation” in many locations. However, FRO specifically is defined as the BA’s “share of the required Frequency Response”. It does not apply to the Interconnection. How can the Interconnection have a share of the required frequency response? A new term may need to be defined for the Interconnection required Frequency Response. **(2)** On page 3 Attachment A states the ERO will post the Frequency Bias Setting for each BA along with their Frequency Response Obligation. Later on the same page, the document states that the BA shall set its Frequency Bias Setting to 100% to 125% of it Frequency Response Measure or Interconnection Minimum. What is the purpose of the ERO determining Frequency Bias Settings if the settings are not going to be used by the BA? What are we missing in the explanation? **(3)** Late on page 3, the document states that BAs are encouraged to notify NERC if load or generation is transferred. Section 4(a) on page 8 of the Rules of Procedure Appendix 5A - Organization Registration and Certification Manual indicates that changes to a Registered Entity’s footprint actually triggers a potential certification audit. Since BAs are required to be certified and moving generation or load from the metered boundaries of one BA to another BA would represent a change in footprint, we suggest removing the word “encouraged” and stating affirmatively that BAs must notify NERC of such changes and referencing the appropriate section of the Rules of Procedure. Otherwise, BAs may not realize notification is actually required.
Response: (1) The drafting team believes the IFRO and FRO terms are used appropriately in Attachment A. Interconnection Frequency Response Obligation is not defined in the standard nor is it a performance obligation. The drafting team has clarified Attachment A in instances when using the terms to address your comments.		

Organization	Yes or No	Question 4 Comment
(2) The ERO is not determining the FBS but is only validating the FBS provided by the BA on FRS Form 1. **(3) The SDT believes these are two coordinated but separate processes. If the Rules of Procedure apply, as worded this document provides the avenue to make the necessary changes to Frequency Bias Setting.**		
Consolidated Edison Co. of NY, Inc.	No	**(1)** This document lacks definitions of terms such as CCadj, DFcc, DFcbr, resource contingency criteria (in the attachment, this is called the "target contingency criteria"), etc. **(2)** Of value to entities would be a sample calculation. **(3)** "The largest category C (N-2) event is used for all interconnections except the Eastern which uses the largest event in the last 10 years". Why aren't all interconnections using the same design contingency design basis? **(4)** The NERC 2012 CPS2 bounds has an Eastern Interconnection frequency bias of -6,360 MW/.1Hz. Can the DT explain why this attachment refers to an Interconnection frequency response obligation of -1,002MW/.1Hz. This is a significant difference.
Response: (1) As stated in Attachment A these terms are defined in the Procedure. The drafting team clarified the use of multiple terms of "resource contingency criteria" throughout both Attachment A and the Procedure documents. **(2) The drafting team will provide a sample calculation of the BA FRO and FRM and post this information on the NERC RS website. The calculation of the IFRO is shown in the Attachment A with the formulas shown in the Procedure document.** **(3) The results for the current Eastern Interconnection model do not represent observed response adequately. The models for the other Interconnections have a better match. For this reason the drafting team has recommended the largest event in the last ten years be used to provide for an increased reliability margin for the Eastern Interconnection. Further details are provided on pages 52 through 55 of the Frequency Response Initiative paper.** **(4) The -6,630 MW/0.1 Hz represents a summation of the Frequency Bias Settings of all Balancing Authorities in the Eastern Interconnection, most of which use the 1% default minimum as required in the current BAL-003-0 standard, which far exceeds their real response. The IFRO of -1002 MW/0.1 Hz is the response determined to avoid the first step of Underfrequency load shedding in the Interconnection for a 4,500 MW generation loss.**		

Organization	Yes or No	Question 4 Comment
American Electric Power	No	AEP is under the impression that there are some requirements, which though not explicitly stated, are implied in Attachment A. AEP feels strongly that these “sub-requirements” should be clarified and contained within the body of the requirements of the standard.
Response: The requirement stated in the standard is the only requirement related to FRM. Attachment A is there to provide uniformity in the calculation of the FRM.		
Duke Energy	No	As indicated in our comments in the past, Duke Energy is certain that as the Interconnection Frequency Bias Setting (FBS) is set closer to the actual Frequency Response in a multi-BA Interconnection, most BAs will be challenged in meeting CPS2, while CPS1 and the proposed Balancing Authority ACE Limit (BAAL) will be more achieveable bounds, and in some cases CPS1 performance will improve. Though probably most of the BAs may welcome a FBS set as high in magnitude as allowed to address the potential compliance risk, there are some which may desire to set their FBS closer to their required minimum allocation rather than have to take on a larger obligation in frequency support under the secondary control measures. Duke Energy believes that this proposed standard should incent BAs to provide more than their share of Frequency Response to the Interconnection and allow that good performance to be recognized; however the requirements described in Attachment A for determining the minimum Frequency Bias Setting (FBS), which requires that the FBS be set no lower in magnitude than the FRM, will leave certain over-performing BAs with no choice but to reduce their actual Frequency Response (still well-above their FRO) if they want to operate with a FBS set closer to the Interconnection Minimum allocation and be relieved of the associated increased obligation for frequency support under the secondary control measures. The FBS is embedded within the secondary control measures of CPS1, CPS2 and the draft Balancing Authority ACE Limit (BAAL). Comparable treatment of similarly-sized BAs (based upon the FRO allocation) is only possible if all BAs are provided the same minimum FBS requirement. To the extent that a BA provides more than its share of response to events, it’s over-performance will only

Organization	Yes or No	Question 4 Comment
		be recognized if its ACE is allowed to reflect a FBS comparable to its peers, allowing its over-performance to be reflected in ACE in support of bringing frequency closer to 60 Hz. Generation control algorithms implemented today to optimize CPS1 will allow non-zero ACE when in support Interconnection frequency within bounds determined by the BA - there should be no concern of “response withdrawal” with such algorithms in place, the BA will simply get credit for such performance. As depicted in the current document, the over-performing BA would be required to set its minimum FBS at its FRM (or greater in magnitude), taking away what should be considered over-performance, erasing it in ACE, and turning it into an obligation under the secondary control measures. Based upon the draft, the only way that the BA could be treated comparably to other similarly sized BAs held only to operating to the Interconnection Minimum allocation, would be to reduce its actual response in FRM to a value less in magnitude than its Interconnection Minimum allocation. Duke Energy believes that BAs should be incented to provide more than their share of Frequency Response, and be given the opportunity to report performance on a basis comparable to similar-sized BAs. Our opinion is that Attachment A ensures that the Interconnection Frequency Bias Setting will remain at some margin above the actual Interconnection Frequency Response in magnitude - the reliability of the Interconnection will not be at risk by allowing over-performing BAs to operate and report performance on a comparable basis to other similarly-sized BAs based upon the Interconnection Minimum allocation if they choose to do so - to that extent, Duke Energy suggests that the language on page 3 be changed to:”A BA using a fixed Frequency Bias Setting may set its Frequency Bias Setting to any number the BA chooses up to 125% of its Frequency Response Measure as calculated on FRS Form 1, but no less in magnitude than its Interconnection Minimum allocation as determined by the ERO.”Regarding the argument which could be offered that a larger FBS in magnitude will also allow wider bounds for control performance, Duke Energy agrees that a large portion of the BA operation will be around 60 Hz where such a benefit could be realized, however it would also come at the cost of a larger obligation than other comparably-sized BAs in sustained support of frequency during the more critical times of significant deviation from 60 Hz where the BA’s compliance could be at risk. Below 59.95 Hz in the Eastern Interconnection (the

Organization	Yes or No	Question 4 Comment
		Frequency Trigger Limit under BAAL), the additional MWs needed to be compliant for any given frequency are greater than the MWs of imbalance allowed by the larger BAAL bound - comparably-sized BAs will not be comparably judged if the standard forces over-performing BAs to assume a larger FBS (in magnitude) than their peers - that should be the decision of the BA. We believe that the proposed language above will create the proper incentive for a Balancing Authority to provide more than its minimum allocation of Frequency Response, and allow it to choose if it wants to make that performance part of a larger FBS (in magnitude), knowing the associated risks and benefits of that decision.Duke Energy supports this standard allowing for Frequency Response Sharing Groups, however the requirements and supporting documents need to clearly allow the FRSG to be treated no differently than if it was a Balancing Authority and shield the participating BAs from compliance scrutiny when all scrutiny should be placed on the FRSG performance as a whole. At the top of Page 3, the standard attachment allows the FRSG to "calculate a group NIA and measure the group response to all events in the reporting year on a single FRS Form 1", however at the bottom of page 3, the standard attachment still requires the FRSG BAs to individually fill out Form 1 and Form 2 for the purposes of determining the minimum Frequency Bias Setting. Duke Energy believes that the standard language in Attachment A, and the supporting form(s), should allow the FRSG, if it chooses, to also report the split of the group FRM which the BAs will use to individually determine their Frequency Bias Setting, rather than require each BA in an FRSG to still maintain Form 1 and Form 2 data. Form 1 could be modified for the FRSG to report the group's FRM along with the split of the FRM among the members, and another form could be developed for each FRSG BA to fill out, replicating only the section of Form 1 (column S) where each BA could provide values for its FRM allocation, its desired FBS, its minimum FBS allocation, and so on.

Response: The drafting team has chosen to reduce the minimum Frequency Bias Settings for individual BAs on a controlled basis on each Interconnection. Your suggestion would eliminate the ability of the drafting team to coordinate the reduction of the minimum Frequency Bias Settings for the BAs. Other commenters have stated that they disagree with reducing the minimum

Organization	Yes or No	Question 4 Comment
Frequency Bias Setting. The drafting team is attempting to balance between the two positions stated in previous postings. The drafting team understands your concern regarding the treatment of FRSG and the minimum Frequency Bias Setting. However, the drafting team believes that this allocation of Frequency Bias among the FRSG members on a basis different from the measured response could be detrimental to reliability under system separation conditions. Future consideration of this issue may be possible once additional information is available.		
Independent Electricity System Operator	No	As indicated in our previous comments, the status of Attachment A is unclear. It is a mixture of requirements, criteria, process and guideline. Making a direct reference in the standard's requirements (R1 and R2) makes Attachment A as part of the requirement and hence is enforceable, but it contains process and guideline information that is not subject to assessment. On the other hand, the absence of a Measure to assess adherence to the criteria and process suggests that Attachment A is not enforceable. It is this ambiguity that makes it difficult for the industry to assess the extent to which they must follow the process. Again, we urge the SDT to keep only the criteria/process parts that must be adhered to in Attachment A, and extract the remaining parts and place them in a guideline document, or an appendix.In addition, the Responsible Entities are required to submit Form 1 and Form 2, but such requirements are not written explicitly as "shall", and are imbedded in the Attachement whose mandatory status is unclear. This makes the standard very confusing from an Responsible Entity's obligation and compliance perspective.
Response: The requirement stated in the standard is the only requirement related to FRM. Attachment A is there to provide uniformity in the calculation of the FRM. The drafting team conscientiously included only reliability objectives in the requirements and put procedural steps in the attachment and procedure.		
BC Hydro	No	BC Hydro agrees with the principles outlined in the Attachment A but has some concerns as follows: 1.Attachment A is no longer recognized as one of the associated document of the proposed Standard in its currently posted version. We believe this was removed by mistake.

Organization	Yes or No	Question 4 Comment
		2.There is no clarity as to how certain factors used in determining the Interconnection FRO such as CCADJ, CBR and BC'ADJ were determined. There is no apparent provision to re-assess any potential changes to these factors over the future years. If such provision is needed or has been provided then consideration should be given to averaging the adjustment over a longer duration (i.e., using the average of the factor observed over a number of years rather than just the year being assessed). 3.The method used for the allocation of the Interconnection FRO to BAs seems to not recognize the fact that frequency response from Load is much less than frequency response from Generation of an equal MW size. 4.If this Attachment A is considered an integral part of the standard then there should be some enforceable measures to ensure applicable entities adhering to the prescribed time line.
Response: **(1) The drafting team disagrees that Attachment A is not one of the associated documents of the standard. It is included by reference in Requirements R1 and R2 and will be attached to the standard upon final approval.** **(2) If the data inputs change then the number will change but the methodology used to calculate the number cannot change without going through the standards process.** **(3) The drafting team agrees with your conclusion. The source of the Frequency Response is not related to the distribution of the obligation.** **(4) The requirement stated in the standard is the only requirement related to FRM. Attachment A is there to provide uniformity in the calculation of the FRM. The drafting team conscientiously included only reliability objectives in the requirements and put procedural steps in the attachment and procedure.**		
Bonneville Power Administration	No	BPA does not agree with the methodology in Attachment A. Please see BPA's response to question 6 as well as BPA's extensive comments submitted on 12/8/11 for Project 2007-12 Frequency Response found at: http://www.nerc.com/docs/standards/sar/2007-12_comments_received_120911.pdf.

Organization	Yes or No	Question 4 Comment
Response: Please refer to our response to Question #6 and our responses to your comments submitted on 12/8/11.		
Exelon Corporation and its affiliates	No	Exelon is troubled by the approach of having requirements that rely so heavily on the attachment to the standard. The use of both of the documents is required to be compliant and this makes it difficult to determine what the obligations are and increases the chance for error in interpretation. The suggested changes below in response to question 8 take information from the Attachment and establish requirements so that an entity does not have to go back and forth between the two documents to identify its obligations. Attachment A should then be modified to include examples of Forms 1 and 2 and instructions for completing the form for Balancing Authorities and Frequency Response Sharing Groups.
Response: The requirement stated in the standard is the only requirement related to FRM. Attachment A is there to provide uniformity in the calculation of the FRM. The drafting team conscientiously included only reliability objectives in the requirements and put procedural steps in the attachment and procedure. **The drafting team will provide a sample calculation of the BA FRO and FRM and post this information on the NERC RS website. The calculation of the IFRO is shown in the Attachment A with the formulas shown in the Procedure document.**		
SERC OC Standards Review Group	No	It is important for NERC to monitor the interaction between the deployment of this standard and its impact on CPS1, CPS2, and BAAL. If performance in the CPS criteria is degraded, there should be a halt in the reduction of the minimum bias setting allowed. There is also concern that we are providing the correct incentives to the entities to provide the appropriate amount of frequency response. We also suggest that clarification be made so that changes in the BA's footprint that would necessitate changes in the bias setting or the FRO be permanent changes, not just temporary. It is unclear how performance would be measured for a BA versus a frequency response sharing group.

Organization	Yes or No	Question 4 Comment
Response: The minimum is not required to be reduced but is allowed to be reduced if no significant impacts are seen on CPS1, CPS2 and BAAL. **The drafting team agrees that temporary changes will not apply in this case. It is a problem that will take care of itself. If two BAs change footprint but do not raise the issue the impact is transparent to the Interconnection. If one BA believes that its limits need to be adjusted the process will adjust the limits of both BAs accordingly.** **The Background Document and Attachment A explain how a FRSG would report. The FRS Forms allow BAs and RSGs to account for contributions from either.**		
PPL NERC Registered Affiliates	No	The NERC posting did not include a redline to Attachment A, therefore, it is not clear what modifications were made. However, there are several modifications that would add clarity to the attachment. The PPL Affiliates support the comments of the SERC OC Standards Review Group on this question, additionally, the following issues should be addressed: In Attachment A, page 3 and elsewhere, clarify that temporary or small transfers of load or generation between BAs do not require notification to the ERO or changes to the FBS or CPS limits. In Attachment A, page 4, a BA should be allowed to be exempt from evaluation any single frequency event where non-conforming load performs contrary to the performance of conventional load (ie. during a frequency decline, the non-conforming load simultaneously increases significantly). By nature, non-conforming load is totally unpredictable, changes quickly, and fluctuates widely. Other than interruption, the BA has no control over the actions of such loads nor can the BA predict or assume any "normal" action by a non-conforming load during a frequency disturbance event. Setting a limit on the number of events that a BA could exempt (regardless of the reason) from FR evaluation in any given year would be more fair and effective in evaluating a BA's frequency response performance.
Response: Please refer to our response to the SERC OC Standards Review Group.		

Organization	Yes or No	Question 4 Comment
The drafting team does not agree that there should be an exemption but has designed the forms to allow for adjustments for non-conforming load. However the BA may find that no adjustment for non-conforming load may be needed due to the measurement over multiple events rather than individual events.		
Kansas City Power & Light	No	The Standard proposes a calculation that overstates the frequency response obligation (FRO) for Balancing Authorities.
Response: The drafting team disagrees with your comment. However, the drafting team cannot provide any detail due to the lack of details in your comment.		
Arizona Public Service Company	No	The supporting document on the standards page does not provide information on CB Ratio and why it is used. It significantly increases FRO and should be justified based upon strong technical basis and actual experience. (Please also see AZPS response to question 6, The Frequency Response Initiative Report should be on the Standards page).
Response: The rationale can be found beginning on page 14 of the Background document and page 49 of the FRI report. **Please refer to our response for Question #6.**		
PJM Interconnection, LLC	No	The target contingency protection criterion for the Eastern Interconnection is the largest event in the last 10 years (believed to be a 2007 event) which is inconsistent with the other Interconnections. Is periodic review required for this criteria? Will this criteria be revised after the referenced event is older than 10 years? Are the other three interconnection's target contingency protection criteria subject to revision if they experience an event larger than a category C? This BA believes that future periodic analysis should be defined and subsequent findings used to support changes via the standard revision process. What are the procedural requirements for revising Attachment A? This BA is concerned that the procedure for revising Attachment A is undefined and

Organization	Yes or No	Question 4 Comment
		that, for example, the IFRO could be increased absent the formal standard revision process, increasing a BA's FRO and subsequently increasing a BA's compliance risk without providing BA's the opportunity to review, comment, and ballot.Related to the previous comment/question, how often are the statistically derived values in Table 1 subject to a required update? For example, the Eastern Interconnection is adjusted due to observed primary frequency response withdrawal ('lazy L' characteristic). The other Interconnections are adjusted for observed differences between point C and point B. As the frequency response characteristics of any Interconnection change, is Table 1 subject to required analysis and revision? This BA believes that future periodic analysis should be defined and subsequent findings used to support changes via the standard revision process. Attachment A indicates that a BA may exclude an event from annual Form 1 FRM evaluation only if its tie-line or frequency data is corrupt or unavailable. This exempts numerous scenarios that could result in a poor response score due to system variations. These could include, but are not limited to, changing energy schedules, changes in load, and AGC driving units up or down due to the ACE value at the time of the frequency event. This subjects the BA to undue compliance risk even though the BA may have adequate frequency responsive resources at the time. This BA suggests that the FRSDT adopt language (and Form 2 functionality) that allows the exclusion of events that are skewed by these types of situations. Attachment A and Forms 1 & 2 specify that 20 to 52 seconds will be used as the post-event B point average for FRM determination. The number of fast responding resources will increase as the technology for batteries, flywheels, and frequency controlled demand side devices moves forward over time. The 20 to 52 second interval does not adequately incentivize the devopment of these technologies.
Response: The results for the current Eastern Interconnection model do not represent observed response adequately. The models for the other Interconnections have a better match. For this reason, the drafting team has recommended the largest event in the last ten years be used to provide for an increased reliability margin for the Eastern Interconnection. Further details		

Organization	Yes or No	Question 4 Comment
are provided on pages 52 through 55 of the Frequency Response Initiative paper. **As the model for the EI is improved and information and experience is gained under this standard the answer to your question will be determined through an open and inclusive process.** **If it is determined that a change in any methodology used in the processes in this standard is needed it would have to go through the standards process.** **The drafting team does not agree that there should be an exemption but has designed the forms to allow for certain adjustments. In addition, the methodology recommended utilizing the median addresses the concerns related to a single event occurrence. Ultimately the BA may find that no adjustment may be needed due to the measurement over multiple events rather than individual events.** **This standard was not intended to provide incentives for the development of new technologies. It is intended to provide for the reliable operation of the Bulk Electric System.**		
Northeast Power Coordinating Council	No	This document lacks definitions of terms such as CCadj, DFcc, DFcbr, resource contingency criteria (in the attachment, this is called the “target contingency criteria”), etc. A sample calculation would be of value to entities. “The largest category C (N-2) event is used for all interconnections except the Eastern which uses the largest event in the last 10 years”. All interconnections should be using the same design basis contingency. The NERC 2012 CPS2 bounds has an Eastern Interconnection frequency bias of -6,360 MW/.1Hz. Why does this attachment refer to an Interconnection frequency response obligation of -1,002MW/.1Hz.? This is a significant difference.
Response: As stated in Attachment A these terms are defined in the Procedure. The drafting team clarified the use of multiple terms of “resource contingency criteria” throughout both Attachment A and the Procedure documents. **The drafting team will provide a sample calculation of the BA FRO and FRM and post this information on the NERC RS website. The calculation of the IFRO is shown in the Attachment A with the formulas shown in the Procedure document.** **The results for the current Eastern Interconnection model do not represent observed response adequately. The models for the other Interconnections have a better match. For this reason, the drafting team has recommended the largest event in the last ten years be used to provide for an increased reliability margin for the Eastern Interconnection. Further details are provided on pages**		

Organization	Yes or No	Question 4 Comment
52 through 55 of the Frequency Response Initiative paper. **The -6,630 MW/0.1 Hz represents a summation of the Frequency Bias Settings of all Balancing Authorities in the Eastern Interconnection, most of which use the 1% default minimum as required in the current BAL-003-0 standard, which far exceeds their real response. The IFRO of -1002 MW/0.1 Hz is the response determined to avoid the first step of Underfrequency load shedding in the Interconnection for a 4,500 MW generation loss.**		
Ameren	No	We disagree on having different methodologies for determining the targets, and would like clarity added for when those targets may change, such as what will happen after the largestest event in the last 10 years rolls off the books for the EI?
Response: The results for the current Eastern Interconnection model do not represent observed response adequately. The models for the other Interconnections have a better match. For this reason, the drafting team has recommended the largest event in the last ten years be used to provide for an increased reliability margin for the Eastern Interconnection. Further details are provided on pages 52 through 55 of the Frequency Response Initiative paper. **If it is determined that a change in any methodology used in the processes in this standard is needed it would have to go through the standards process.** **As the model for the EI is improved and information and experience is gained under this standard the answer to your question will be determined through an open and inclusive process.**		
Manitoba Hydro	Yes	(1) Page 2, Balancing Authority Frequency Response Obligation (FRO) and Frequency Bias Setting: States that the ERO is responsible for "annually assigning an FRO and Frequency Bias Setting to each BA." No mention is made of FRSGs. (2) Neither R1 nor the referenced Attachment A clarifies the FRM requirements for an FRSG to comply versus a BA. In particular, compared to BAL-002-0 R1.1, which clearly states that the BA may elect to fulfill its obligation through an FRSG and that in such cases the FRSG has the same responsibilities as each BA (that is a participant in the FRSG). (3)Attachment A refers to an FRSG calculating FRM, but the standard does not.

Organization	Yes or No	Question 4 Comment
Response: 1) - The FRSG FRO is a summation of its members' FROs. **2) & 3) -The drafting team believes that it is clearly stated for a FRSG compliance with R1. The Requirement reads "Each Frequency Response Sharing Group (FRSG) or Balancing Authority that is not a member of a FRSG shall achieve an annual Frequency Response Measure (FRM) (as calculated and reported in accordance with Attachment A) that is equal to or more negative than its Frequency Response Obligation (FRO) to ensure that sufficient Frequency Response is provided by each FRSG or BA that is not a member of a FRSG to maintain Interconnection Frequency Response equal to or more negative than the Interconnection Frequency Response Obligation."**		
Texas Reliability Entity	Yes	1. The calculation for the FRO for ERCOT includes a credit of 1400 MW for load resources. 1400 MW is currently the maximum amount of LR that can be procured through the ERCOT ancillary service process. There can be periods during the day where 1400 MW was not procured or is not available (It was noted during the summer of 2012 that on some days, only 900 MW of LR was available through the ancillary service process). Should the calculated IFRO (-286 MW per 0.1 Hz) be modified to account for this variation? 2. Background Document says: "Attachment A proposes the following Interconnection event criteria as a basis to determine an Interconnection's Frequency Response Obligation: o Largest category C loss-of-resource (N-2) event o Largest total generating plant with common voltage switchyard o Largest loss of generation in the interconnection in the last 10 years" For ERCOT, the largest loss of generation in the last 10 years was over 3400 MW, and does not match the 2750 MW (N-2) value used for the IFRO calculation.
Response: **(1) The process used to determine the IFRO has been vetted through multiple forums. The drafting team feels that the proposed calculation is appropriate for the standard at this time. As experience is gained through the implementation of this standard, the calculation will be reviewed and any adjustments will be addressed through an open and inclusive process.** **(2) The results for the current Texas Interconnection model represent observed response adequately so the recommended Resource Contingency Criteria for ERCOT is the Category C N-2 event. For further details related to the full determination,**		

Organization	Yes or No	Question 4 Comment
please refer to the Frequency Response Initiative paper.		
SPP Standards REview Group	Yes	Delete the 2nd 'that' in the 2nd bullet at the top of page 3.
Response: Thank you for the comment. The drafting team has made the correction.		
Xcel Energy	Yes	It is not clear however, as to if this is actually part of the standard or if it is a document that can be revised without going through the standards development process. Also, the formatting of the document should be modified to clearly identify where 'steps/actions' are needed from responsible parties, whether that be the ERO or BA/FRSG.
Response: If it is determined that a change in any methodology used in the processes in this standard is needed it would have to go through the standards process. **Please refer to the "timeline" on page #6 of Attachment A as this clearly provides for who has responsibility for each step in the process.**		
NextEra Energy	Yes	NextEra Energy does not support the changes made. It is concerned that certian changes were made to help some large East coast entities that could not comply at the expense of the FRCC region. Specifically, now on page 3 of Attachment A 4th paragraph from the bottom the statement is made " sets its frequency bias to the greater of". We believe that this must be changed to either Statement 1 " Any number the BA chooses between 100% etc"Or Statement 2 " Interconnection minimum as determined by the ERO" Without this change, NextEra beleives the FRCC will be unfiarly treated relative to others on the Eastern Interconnection. The technical reasons for this is concern was explained during the Standard Drafting Team meetings. In addition, the ERO limit which is set at 0.9% of load should be changed to read within 0.8 or 0.9% of peak load based on the BA's choice. Also, see page 7 of the Procedure document and compare to page 1 of Attachment A.

Organization	Yes or No	Question 4 Comment
		The formulae abbreviations for the variables in the Procedure are not likewise abbreviated in Attachment A. For example, “Credit for LR” on Attachment A is “CLR” in the Procedure, but it requires cross checking each document to figure this out. Or CBr in Attachment A, Table 1 is represented as DFCBR in the Procedure, Page 7. Since the same variables are being described, these should be represented the same way in both documents throughout. 2. Similarly, is “IFRO” in Table 1 of Attachment A the same as “FROInt” of the equation that follows on page 2? The same abbreviation should be used to represent this variable. The documents should be revised in general along these lines for all terms. 3. In Procedure document, page 5, paragraph 3 it should read “Table 2”, not “1”. 4. In the Procedure, it would be good to show Table 1 and Table 2 as Table 1 of Attachment A (i.e. use table lines and borders). 5. At least in the first usage, ERO in the Procedure document should be spelled out as “Electric Reliability Organization (ERO)”. 6. In Table 1 of Attachment A, the two footnotes preceded by asterisks (single and double on page 2) should be connected to the table by adding a single superscripted asterisk to the Eastern UFLS value of 59.5, and a double superscripted asterisk to the ERCOT LR value of 1,400.

Response:

(1) The drafting team does not believe any BAs were favored over other BAs. However the drafting team is unclear as to your expressed concerns related to FRCC. In direct communications with FRCC they concluded that the IFRO starting frequency of the prevalent 59.5 Hz for the Eastern Interconnection is acceptable in that it imposes no greater risk of UFLS operation in FRCC for an external resource loss event than for an internal FRCC event.
The drafting team does not agree with the recommended wording change for the bias setting because it would essentially remove the Interconnection minimum FBS. The drafting team does not agree that we are mixing terms between the Procedure and Attachment A. The drafting team uses CBR and DFCBR in both documents defining two different variables. The drafting team clarified CLR.

Organization	Yes or No	Question 4 Comment
(2) The drafting team clarified IFRO/FRO in the documents. **(3) Thank you. The drafting team has corrected this in the document.** **(4) The drafting team thanks you for your comment. However, the majority of the industry does not support your suggested modification. Therefore, the drafting team will leave the tables as shown.** **(5) The drafting team changed ERO to Electric Reliability Organization as per your suggestion.** **(6) Thank you. The drafting team has made the changes.**		
NREL Transmission and Grid Integration Group	Yes	Table 1: CB_r units should be unitless, CB'adj should be Hz.
Response: Thank you for the comment. The drafting team has made these changes.		
NV Energy	Yes	This document is improved, and satisfactorily addresses comments from the prior posting.
Response: Thank you for the comment.		
New York Independent System Operator	Yes	With a new process we are concerned that the interconnection minimum will initially move from 1.0% to 0.9%.
Response: Thank you for your comment. The new process moves the minimum from 1.0% to 0.9%.		
MRO NSRF	Yes	
Edison Electric Institute	Yes	
pacificorp	Yes	
California Independent System Operator	Yes	

Organization	Yes or No	Question 4 Comment
Energy Mark, Inc.	Yes	
Tacoma Power	Yes	
Southern Company	Yes	
Idaho Power Company	Yes	
Tucson Electric Power	Yes	
Keen Resources Asia Ltd.	Yes	
MISO	Yes	
Puget Sound Energy		In reviewing the Consideration of Comments document, it is clear that the standard drafting team does not wish for the administrative elements of Attachment A to become items addressed during compliance evaluations ("There is no intent to require filing on a certain date and to have the BA prove to the auditor that a filing was made on that date." This quote appears at several places in the Consideration of Comments documents, but first at page 113). However, because Attachment A is referenced in the standard, its provisions, including the timing table, are all mandatory and enforceable. This result is emphasized by the language of requirement R1, which states that entities "...shall achieve an annual Frequency Response Measure (FRM) as calculated and reported in accordance with Attachment A...." This language means that a failure to file a document on a date specified in the attachment would be a potential compliance violation. Because Attachment A is mandatory and enforceable, the standard drafting team should carefully review its provisions and clarify which elements are requirements and which elements are background statements or guidance. In addition, the use of additional headings and section numbers would add in clarifying the document (for example, at the top of page 3, there is a discussion of how an FRSG would calculate its FRM; however, there is an entire section beginning on

Organization	Yes or No	Question 4 Comment
		page 4 addressing FRM where that discussion should instead appear).

Response: The requirement stated in the standard is the only requirement related to FRM. Attachment A is there to provide uniformity in the calculation of the FRM. The drafting team conscientiously included only reliability objectives in the requirements and put procedural steps in the attachment and procedure.

5. **The SDT has moved a portion of the material located in Attachment A and all of the material located in "Attachment B- Process for Adjusting Bias Setting Floor" into a new document "Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard". The SDT created this document to assign tasks to the ERO and provide instructions for the ERO to follow when carrying them out under the BAL-003-1 standard. Do you agree that the ERO should perform these tasks and that this document provides sufficient detail for the ERO to do it under the BAL-003-1 standard? If not, what needs to be added to the document?".**

Summary Consideration: Several commenters requested clarity on how modifications to the Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard would be made. The drafting team explained that the "Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard" was not incorporated into the BAL-003 Frequency Response Reliability Standard. As such, modifications to the Procedure will not be developed through the standard development process. Consistent with NERC's commitment to an open and transparent process, the procedure for modifying the event selection process for supporting the Frequency Response Standard is set forth in the opening paragraph of the Procedure for ERO Support of Frequency Response and Frequency Bias Setting document. NERC will post suggested modifications for a 45-day formal comment period, respond to all comments and will discuss the revision request in a public meeting. Revisions will be provided to the NERC BOT for approval and in addition, any modifications will be filed with FERC for informational purposes. This process provides the industry assurance that changes will be properly vetted and that there is an opportunity for stakeholder input.

A couple of commenters questioned how events would be excluded, specifically with regards to during ramping periods. The drafting team stated that all events are considered. Events that occur over known ramping periods are selected last. As an example, the event reflected in the right graph shown in the Procedure would be selected over the event reflected in the graph on the left. If an inadequate number of events are available for that season, then these events may be used. The benefit of using the median of at least 20 events in a year helps minimize the impact of outliers.

A few commenters did not understand why the frequency criteria are different for each Interconnection. The drafting team explained that the frequency criteria was different for each interconnection because the frequency used to measure frequency response is interconnection dependent and varies differently for each interconnection. Larger interconnections have greater frequency response and as a consequence smaller frequency deviations for events of the size typically experienced.

One or two commenters questioned whether certain events should always be included in the evaluation process. The drafting team stated that based on event evaluation by this drafting team, it has been determined that it is impossible to require certain events to be included. This is the reason that the drafting team has developed the Event Selection Criteria.

Organization	Yes or No	Question 5 Comment
Keen Resources Asia Ltd.	No	As a professionally trained published statistical expert never compensated by any balloting participant, I consider event selection criterion 7 to be unacceptable because it violates the fundamental statistical procedure of sampling statistical data "as is" and not pre-selecting the data (to fit some preferred even-distribution over time) and therefore biasing it before applying any statistical procedure to the data. Event criterion 6 is also unacceptable for being an an "ad hoc" explicit exclusion, from the definition of the frequency response being measured, of response to frequency events that occur during a specific kind of scheduled generation and load changes. Said exclusion needs to be written into the definition of the Frequency Response that is being measured. It is procedurally improper and unacceptable to bias the sampling procedure by explicit exclusion of data as an alternative to redefining the thing being sampled. In that case it's not generic Frequency Response that is being sampled, but some specific Frequency-Response-less-Response-to-Excluded-Events that is being measured. It is non-transparent and subterfuge to avoid instead accordingy reworking/narrowing the definition of Frequency Response, especially as said reworking requires a clear technical justification that is absent from this standard, and modifying the existing NERC Glossary definition of Frequency Response which Criterion 6 therefore stands in flat violation of.
Response: Criterion 7 is included in the Event Selection Criteria because the drafting team considers it very important to be able to select and finalize events for analysis quarterly so that the BAs can evaluate their performance as the measurement year unfolds. This necessarily requires minimal criteria to insure that this selection and finalization process can be completed quarterly. The drafting team recognizes that this finalization may have some effect on the sampling, but values the quarterly selection and finalization more than the pure statistical sampling theory. This is a trade-off that the drafting team has chosen to make. Once several years of a regular disparity between seasons of the year were established in terms of number of events in a season, the industry could propose modifying the Standard at that time to adjust Criterion 7 accordingly. **Criterion 6 is included because historic data indicate that the periods within 5 minutes of the top of the hour have shown to have**		

Organization	Yes or No	Question 5 Comment
higher frequency variability than other periods in the hour. Statistical analysis presented in the FRI Report indicates that pre-disturbance frequency is a significant contributor to the variability of frequency response. The drafting team has chosen to allow the exclusion of events close to the top of the hour when other acceptable events are available until analysis is done of whether these periods have a statistically different frequency response and therefore introduce bias. Meanwhile, as Balancing Authorities are moving toward quarter-hourly scheduling, the higher top-of-the-hour frequency variability prompting the need and application of Criterion 6 is expected to disappear. Therefore, while your recommended alternative of changing the NERC definition of Frequency Response may be statistically correct, from a practical perspective it would likely prove to be a needless chore and to yield a needlessly complicated definition only to have to be changed back again.		
Southern Company	No	Attachment A states that Form 1 is posted annually. The ERO support document selects events annually. The timing for the two documents needs to be aligned so that the set of selected events does not change from quarter to quarter. (If three events are selected for the first quarter those same events will be a sub-set of the 20 events selected for the annual compliance calculations.)
Response: Attachment A indicates that Form 1 with the events from the previous quarter is posted on May 10th, August 10th, November 10th and the second business day in February. It is the intent of the standard that events once posted will be included in the FRM analysis.		
BC Hydro	No	BC Hydro agrees in principle that the ERO should perform these tasks related to BAL-003-1 but has the following concerns: 1. There is no clear indication whether the Interconnection FRO will be calculated every year, and if yes, how each of the factors involved will be determined. 2. It is not clear whether data gathered in these procedures are only for the determination of annual FRO and FBS, or also to determine whether the BA or the FRSG was in compliance to BAL-003-1 for the assessed year. Since the ERO in this Document seems to be the NERC Resources Subcommittee and its Frequency Work Group, we think this fact should be made clear. The Background document should also be reviewed to ensure its alignment in this regard.

Organization	Yes or No	Question 5 Comment
Response: The drafting team has chosen to use the methods presented in the FRI Report to determine the values presented in Table 1 of Attachment A to determine the Interconnection FRO. If the method of calculation by the ERO or the base starting values used to determine the IFRO change (i.e. Resource Contingency Criteria or Prevailing UFLS First Step), then those changes will be subject to the standards process to accept those changes. If the statistical determinates used in the method change (i.e. Starting Frequency, CC_{ADJ}, CB_R, BC'_{ADJ}, and Credit for LR) or the data used to allocate the IFRO among the BAs (i.e. FERC Form 714 data) changes, the new values will be implemented without being subject to the standards process. The data gathered for the FRO calculation is not compliance related. The calculation of FBS is also not compliance related. However, assuming the information is entered into FRS Form 1 correctly then the FBS number will be used by an auditor to determine compliance with Requirement R2. The drafting team has been instructed by NERC to refer to all NERC entities (i.e. Frequency Working Group, Resources Subcommittee, etc) as the ERO.		
Bonneville Power Administration	No	BPA does not agree with the methodologies outlined in Attachment B. Please see BPA's response to question 6 as well as BPA's extensive comments submitted on 12/8/11 for Project 2007-12 Frequency Response found at: http://www.nerc.com/docs/standards/sar/2007-12_comments_received_120911.pdf
Response: Please refer to our response to your comment for Question #6 and our responses to your comments dated 12/8/11.		
Kansas City Power & Light	No	Criteria 3 - Why are frequency thresholds different between regions when generator governor reaction is supposed to be the same between regions? Criteria 5 - What is the reasoning that multiple events that are not stabilized within 18 seconds not being considered? Criteria 6 - How are "changes in scheduled interchange" or load change determined in regions with interconnections with multiple BAs with different time zones?
Response: The frequency criteria is different for each interconnection because the frequency used to measure frequency response is interconnection dependent and varies differently for each interconnection. Larger interconnections have greater frequency response and as a consequence smaller frequency deviations for events of the size typically experienced.		

Organization	Yes or No	Question 5 Comment
The standardized method used to measure frequency response will not work correctly for events that have not stabilized within 18 seconds. **This determination will be made by the ERO (presently the Frequency Working Group).** **All events are considered. Events that occur over known ramping periods are selected last. As an example, the event reflected in the right graph shown in the Procedure would be selected over the event reflected in the graph on the left. If an inadequate number of events are available for that season, then these events may be used. The benefit of using the median of at least 20 events in a year helps minimize the impact of outliers.**		
Duke Energy	No	Duke Energy agrees with allowing the ERO to perform this function, however the industry needs some assurance that this Procedure cannot be changed outside of the Standards Process for approval by the industry. In the sixth line of the third paragraph on page 5, the statement should reference Table 2. Page 5 reads as if the BAs will submit their data based upon Form 1 which includes an adjustment to the Interconnection peak load (initially 0.9), and then the ERO will determine whether the Interconnection minimum FBS is still more than 20% above the measured response - if so, the minimum FBS will be adjusted, requiring the BAs to reassess their new minimum FBS based upon a different factor, and decide whether to use that value or choose a value up to 125% of their FRM, resulting in another iteration of values being submitted to the ERO. If the ERO is going to do an independent assessment of Interconnection Frequency Response to the events, on an annual basis prior to gathering data from the BAs, the ERO could compare the total FBS being used by the BAs against the estimated Frequency Response over that period to determine if an adjustment is warranted, and then the ERO could include the appropriate adjustment factor (0.9, 0.8, etc..) in Form 1 for the BAs to use. If the ERO is not going to estimate the Frequency Response aside from the BAs, multiple iterations will be likely. Duke Energy suggests the following language to cover the point above: "On an annual basis, the ERO will review the Interconnection total minimum Frequency Bias Setting for the prior period and compare it against the Interconnection's total natural Frequency Response determined for that period. If an Interconnection's total minimum Frequency Bias Setting exceeds (in absolute value) the Interconnection's total natural

Organization	Yes or No	Question 5 Comment
		Frequency Response by more (in absolute value) than 0.2 percentage points of the Interconnection non-coincident peak load (expressed in MW/0.1Hz), the minimum Frequency Bias Setting for BAs within that Interconnection may be reduced (in absolute value) based on the technical evaluation and consultation with the regions affected by 0.1 percentage point of Interconnection non-coincident peak load (expressed in MW/0.1Hz) to better match that Frequency Bias Setting and natural Frequency Response. The ERO will include the adjustment factor in the Interconnection Form 1 used by the Balancing Authorities for the calculation of the new minimum Frequency Bias Setting. The Form 1 information from the Balancing Authorities will be gathered by the ERO in coordination with the regions of each Interconnection to determine the final Interconnection Frequency Bias Setting for the next period."
Response: The "Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard" is not incorporated into the BAL-003 Frequency Response Reliability Standard. As such, modifications to the Procedure will not be developed through the standard development process. Consistent with NERC's commitment to an open and transparent process, the procedure for modifying the event selection process for supporting the Frequency Response Standard is set forth in the opening paragraph of the Procedure for ERO Support of Frequency Response and Frequency Bias Setting document. NERC will post suggested modifications for a 45-day formal comment period, respond to all comments and will discuss the revision request in a public meeting. Revisions will be provided to the NERC BOT for approval and in addition, any modifications will be filed with FERC for informational purposes. This process provides the industry assurance that changes will be properly vetted and that there is an opportunity for stakeholder input. **The reference has been changed from Table 1 to Table 2. Thank you for your comment.** **The review of the information provided by the BAs discussed in the Procedure document will take a significant amount of time. Therefore, the change to the Interconnection Minimum Frequency Bias Setting will occur on the subsequent year's Form 1. This will eliminate the risk of multiple iterations and allow sufficient time for the ERO to consult with the regions as indicated in the Procedure. The drafting team has included clarifying language in the document.**		
Tucson Electric Power	No	I think it should be more clear or better defined that an interconnection does have some input into what events are selected.

Organization	Yes or No	Question 5 Comment
Response: Thank you for your comment. Each interconnection has a representative on the Frequency Working Group that performs the selection of events.		
Exelon Corporation and its affiliates	No	Please see response to question 8.
Response: Thank you for your comment. Please see response to Question 8.		
PJM Interconnection, LLC	No	The Procedure indicates that events that occur when 'large interchange schedule ramping or load change is happening' and 'events occurring within 5 minutes of the top of the hour' should be excluded from consideration. Since interchange schedule ramping and load change occurs at the BA level, this BA believes that the Procedure allows for the selection of events that occur when a BA is experiencing these conditions but Attachment A does not allow for exemption of these events. Also, the Procedure specifies that events that occur at the top of the hour be excluded, if other qualifying events exist, but this does not take into consideration energy markets that allow for sub-hourly schedule changes (e.g. 15 minutes) and the BA is not permitted to exempt these events on Form 1 subjecting the BA to undue compliance risks.
Response: Thank you for your comment. All events are considered. Events that occur over known ramping periods are selected last. As an example, the event reflected in the right graph shown in the Procedure would be selected over the event reflected in the graph on the left. If an inadequate number of events are available for that season, then these events may be used. The benefit of using the median of at least 20 events in a year helps minimize the impact of outliers.		
Texas Reliability Entity	Yes	1. Event Selection Criteria Item 2: Should certain events require mandatory inclusion for FRM calculation (i.e. DCS events)? 2. Event Selection Criteria Item 6: We disagree with the way this is worded. If a unit trips during this time, as it often can, measured frequency response needs to occur. We understand that the results are impacted by the grid condition and perhaps that is why the SDT decided to exclude the issue. Need to define what is intended by a "large"

Organization	Yes or No	Question 5 Comment
		interchange ramp schedule or load change. May also want to consider changing the language from "will be excluded from consideration" to "MAY be excluded from consideration".
Response: Thank you for your comment. Based on event evaluation by this drafting team, it has been determined that it is impossible to require certain events to be included. This is the reason that the drafting team has developed the Event Selection Criteria. **The drafting team wrote the criteria to allow flexibility for any change that significantly impacts frequency.** **The drafting team looked at the language and determined that the present language provides greater clarity. The "will be excluded" is followed by "…if other acceptable frequency excursion events from the same quarter are available." Therefore, it is not a mandatory exclusion.**		
Edison Electric Institute	Yes	EEI supports the ERO's role as defined in the procedure but is concerned that the procedure, unlike approved NERC standards, is unbounded by the current rules for developing standards. For that reason, EEI recommends that the procedure become more formalized and integrated into the standard as an addendum thereby avoiding any Industry concerns that future modification might occur outside the approved processes
Response: Thank you for your comment. The "Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard" is not incorporated into the BAL-003 Frequency Response Reliability Standard. As such, modifications to the Procedure will not be developed through the standard development process. Consistent with NERC's commitment to an open and transparent process, the procedure for modifying the event selection process for supporting the Frequency Response Standard is set forth in the opening paragraph of the Procedure for ERO Support of Frequency Response and Frequency Bias Setting document. NERC will post suggested modifications for a 45-day formal comment period, respond to all comments and will discuss the revision request in a public meeting. Revisions will be provided to the NERC BOT for approval and in addition, any modifications will be filed with FERC for informational purposes. This process provides the industry assurance that changes will be properly vetted and that there is an opportunity for stakeholder input.		
ACES Power Marketing	Yes	Overall, we agree. However, we suggest the document clarify that the ERO shall

Organization	Yes or No	Question 5 Comment
Standards Collaborators		perform these tasks in coordination with the Resources Subcommittee. It consists of industry experts that can be an extra resource to NERC. Furthermore, NERC staff working with the Resources Subcommittee will provide additional transparency to the process.
Response: Thank you for your comment. The drafting team has been instructed by NERC to refer to all NERC entities (i.e. Frequency Working Group, Resources Subcommittee, etc) as the ERO.		
MISO	Yes	The first hyperlink on page 3 of the Procedure for ERO Support does not work.
Response: Thank you for your comment. The drafting team has corrected this.		
Xcel Energy	YES	It is not clear however, as to if this is actually part of the standard or if it is a document that can be revised without going through the standards development process. Also, the formatting of the doucment should be modified to clearly identify where 'steps/actions' are needed from repsonsible parties, whether that be the ERO or BA/FRSG.
Response: Thank you for your comment. The "Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard" is not incorporated into the BAL-003 Frequency Response Reliability Standard. As such, modifications to the Procedure will not be developed through the standard development process. Consistent with NERC's commitment to an open and transparent process, the procedure for modifying the event selection process for supporting the Frequency Response Standard is set forth in the opening paragraph of the Procedure for ERO Support of Frequency Response and Frequency Bias Setting document. NERC will post suggested modifications for a 45-day formal comment period, respond to all comments and will discuss the revision request in a public meeting. Revisions will be provided to the NERC BOT for approval and in addition, any modifications will be filed with FERC for informational purposes. This process provides the industry assurance that changes will be properly vetted and that there is an opportunity for stakeholder input.		
Manitoba Hydro	Yes	No comment.
NREL Transmission and Grid	Yes	

Organization	Yes or No	Question 5 Comment
Integration Group		
SPP Standards REview Group	Yes	
pacificorp	Yes	
California Independent System Operator	Yes	
Energy Mark, Inc.	Yes	
Idaho Power Company	Yes	
Independent Electricity System Operator	Yes	
NV Energy	Yes	
New York Independent System Operator	Yes	
MRO NSRF		MRO NSRF AGREES

6. The SDT is now using the method detailed in the Frequency Response Initiative Report dated September 30, 2012 to calculate the Interconnection Frequency Response Obligation. Do you agree that this method provides for the proper amount of Frequency Response? If not, what specifically needs to be changed?

Summary Consideration: Many of the commenters requested clarification on how changes to the methodology defined in Attachment A could be modified. The drafting team explained that Attachment A was part of the standard and as such is subject to the NERC standards process for making any changes.

Several commenters questioned the use of the largest event in the last 10 years for the Eastern Interconnection. The drafting team stated that the results for the current Eastern Interconnection model do not represent observed response adequately. The models for the other Interconnections have a better match. For this reason the SDT has recommended the largest event in the last ten years be used to provide for an increased reliability margin for the Eastern Interconnection. If the largest event in the last 10 years falls below 4500 MW then the SDT believes that an N-2 event would be utilized.

One commenter wanted a method to discount outliers. The drafting team explained that this was one of the reasons that they had chosen the median as the appropriate measure for FRM. The benefit of using the median of at least 20 events per year helps to minimize the impact of outliers.

Organization	Yes or No	Question 6 Comment
Bonneville Power Administration	No	BPA does not have specific changes to the methodology to suggest, however, a methodology that arrives at a negative 840 MW per tenth Hz for WECC is obviously under-calculating the frequency bias obligation. Currently WECC has an interconnection bias of over 2000 MW / 0.1Hz and with this bias the frequency is steady state following point B on the frequency response curve. BPA would expect to see frequency decline after point B if the FBO is lowered by almost 60%. BPA also must reiterate that there is still a problem with the method used for modifying the FBO and frequency bias for Balancing Authorities. A high-performing Balancing Authority will have its frequency bias increased each year due to higher response during the events chosen by the ERO. Conversely, a low-performing Balancing Authority will have its frequency bias reduced each year due to lower response during the events chosen by

Organization	Yes or No	Question 6 Comment
		the ERO.
Response: After review of comments, the drafting team feels confident with the current method of calculating Frequency Response Obligation as outlined in the Frequency Response Initiative report. This standard requires minimum bias setting not to be less than 0.9% of the non-coincidental peak load for a multi-BA interconnection. This will ensure that minimum bias settings will be based on Interconnection's non-coincidental peak load rather than biased toward low-performer. The minimum Frequency Bias settings requirement are outlined in Table 2 of "Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard" **The drafting team points out that there is not a Frequency Bias obligation and that the currently measured response for the Western Interconnection is approximately -1200 MW/0.1 Hz. This number is above, but much closer to the required level of -840 MW/0.1 Hz under this standard.**		
Tucson Electric Power	No	I believe that the frequency bias obligation of the Western Interconnection is understated.
Response: The drafting team points out that there is not a Frequency Bias obligation and that the currently measured response for the Western Interconnection is approximately -1200 MW/0.1 Hz. This number is above, but much closer to the required level of -840 MW/0.1 Hz under this standard.		
Duke Energy	No	Similar to our earlier concern, the industry needs some assurance that the calculation of the Interconnection FRO described in the report cannot be changed outside of the Standards Process for approval by the industry. Duke Energy does not support using a 4500 MW loss as the basis for determining the FRO for the Eastern Interconnection for future events. However, as the calculation also includes 59.5 Hz as the basis for determining the FRO, the result is an allocation which can be supported. To the extent that the standard drafting team moves in the direction of using 59.7 Hz as the basis for the FRO, then it needs to follow a methodology similar to the other Interconnections for determining the credible multiple contingency to cover.
Response: Thank you for your comment. The Attachment A is part of the standard and as such is subject to the NERC standards		

Organization	Yes or No	Question 6 Comment
process manual for making any changes. The drafting team agrees with your concern regarding the use of 4500 MW. However, the results for the current Eastern Interconnection model do not represent observed response adequately. The models for the other Interconnections have a better match. For this reason the SDT has recommended the largest event in the last ten years be used to provide for an increased reliability margin for the Eastern Interconnection. If the largest event in the last 10 years falls below 4500 MW then the SDT believes that an N-2 event would be utilized.		
New York Independent System Operator	No	The drafting team should consider some method for discounting outliers, that may not be explainable.
Response: Thank you for your comment. All events are considered. Events that occur over known ramping periods are selected last. As an example, the event reflected in the right graph shown in the Procedure would be selected over the event reflected in the graph on the left. If an inadequate number of events are available for that season, then these events may be used. The benefit of using the median of at least 20 events in a year helps minimize the impact of outliers.		
Southern Company	No	The industry needs some assurance that the calculation of the Interconnection FRO described in the report cannot be changed outside of the Standards Process for approval by the industry. We do not support using a 4500 MW loss as the basis for determining the FRO for the Eastern Interconnection for future events. However, as the calculation also includes 59.5 Hz as the basis for determining the FRO, the result is an allocation which can be supported. To the extent that the standard drafting team moves in the direction of using 59.7 Hz as the basis for the FRO, then it needs to follow a methodology similar to the other Interconnections for determining the credible multiple contingency to cover.
Response: Thank you for your comment. The Attachment A is part of the standard and as such is subject to the NERC standards process for making any changes. The drafting team agrees with your concern regarding the use of 4500 MW. However, the results for the current Eastern Interconnection model do not represent observed response adequately. The models for the other Interconnections have a better match. For this reason, the drafting team has recommended the largest event in the last ten years be used to provide for an		

Organization	Yes or No	Question 6 Comment
increased reliability margin for the Eastern Interconnection. If the largest event in the last 10 years falls below 4500 MW then the SDT believes that an N-2 event would be utilized.		
PPL NERC Registered Affiliates	No	The PPL Affiliates support the comments of the SERC OC Standards Review Group on this question
Response: The Attachment A is part of the standard and as such is subject to the NERC standards process for making any changes. **The drafting team agrees with your concern regarding the use of 4500 MW. However, the results for the current Eastern Interconnection model do not represent observed response adequately. The models for the other Interconnections have a better match. For this reason, the drafting team has recommended the largest event in the last ten years be used to provide for an increased reliability margin for the Eastern Interconnection. If the largest event in the last 10 years falls below 4500 MW then the SDT believes that an N-2 event would be utilized.**		
Keen Resources Asia Ltd.	No	This question is falsely worded. The SDT is specifically NOT using the method detailed in the Frequency Response Initiative Report dated September 30, 2012. So the term "this method" is practically meaningless in this question because it is not clear if it means "the SDT's method" or "the FRI's method". The Background Document specifically states on page 29: "The NERC Frequency Response Initiative Report addressed the relative merits of using the median versus linear regression for aggregating single event frequency response samples into a frequency response measurement score for compliance evaluation. This report provided 11 evaluation criteria as a basis for recommending the use of linear regression instead of the median for the frequency response measurement aggregation technique. The FRSDT made its own assessment on the basis of these evaluation criteria on September 20, 2012, but concluded that the median would be the best aggregation technique to use initially when the relative importance of each criterion was considered." What needs to be changed, besides properly wording this question? The FRI method of linear regression should be adopted, and the SDT method of median should be rejected, in the standard to change the first sentence of this question into a true statement from a false statement and to, in answer to the question, provide for the proper amount of

Organization	Yes or No	Question 6 Comment
		Frequency Response.
Response: Thank you for your comments. The drafting team disagrees that the methodology for calculating the IFRO used in this standard is different than that detailed in the FRI Report. The drafting team considered replacing median with linear regression but chose to use the median because of its better resiliency to data quality problems found in the Actual Net Interchange data used in the frequency-response calculation.		
SERC OC Standards Review Group	No	We believe the industry needs some assurance that the calculation of the interconnection FRO cannot be changed without rigorous review and input from the industry. In addition the clarification should be made how the one in ten year loss for the Eastern Interconnection (4500 MW) would change after 10 years. Would the same methodology be used or would the largest Category C (n-2) be used?
Response: Thank you for your comment. The Attachment A is part of the standard and as such is subject to the NERC standards process manual for making any changes. **The drafting team agrees with your concern regarding the use of 4500 MW. However, the results for the current Eastern Interconnection model do not represent observed response adequately. The models for the other Interconnections have a better match. For this reason, the drafting team has recommended the largest event in the last ten years be used to provide for an increased reliability margin for the Eastern Interconnection. If the largest event in the last 10 years falls below 4500 MW then the SDT believes that an N-2 event would be utilized.**		
Arizona Public Service Company	NO	1. The Frequency Response initiative report should be added to the standard as an appendix. It is not clear where to find this report. 2. The jusitification for dividing delta frequency with C to B ratio is not adequate and not clear.
Response: Thank you for your comment. 1) The drafting team disagrees that the FRI Report should be attached to this standard as an appendix. We do agree that it should be easier to locate. **2) Please refer to the FRI Report for the reasoning you request.**		
Edison Electric Institute	Yes	EEI finds the method to be acceptable but as mentioned in our response to question

Organization	Yes or No	Question 6 Comment
		No. 5 (above), we believe that the procedure should be more formally documented as an addendum. Such a change would ensure that the document would remain unchanged outside of the approved standards making process. Additionally, EEI does not support using 4500 MW loss as the basis for determining the FRO for the Eastern Interconnection for future events. However, as the calculation also includes 59.5 Hz as the basis for determining the FRO, the results is an allocation which we believe is acceptable. In the future, should the SDT decide to use 59.7 Hz as the basis for the FRO, than it will need to follow a methodology similar to the other interconnections for determining the credible multiple contingency to cover.
Response: Thank you for your comment. The Attachment A is part of the standard and as such is subject to the NERC standards process manual for making any changes. **The drafting team agrees with your concern regarding the use of 4500 MW. However, the results for the current Eastern Interconnection model do not represent observed response adequately. The models for the other Interconnections have a better match. For this reason the drafting team has recommended the largest event in the last ten years be used to provide for an increased reliability margin for the Eastern Interconnection. If the largest event in the last 10 years falls below 4500 MW then the SDT believes that an N-2 event would be utilized.**		
ACES Power Marketing Standards Collaborators	Yes	We agree that this method will provide sufficient frequency response. However, we believe Interconnection Frequency Response Obligation is used inconsistentently with the definition of Frequency Response Obligation as documented in our response to other comments.
Response: Please refer to our responses to your other comments.		
Manitoba Hydro	Yes	No comment.
NREL Transmission and Grid Integration Group	Yes	
SPP Standards REview	Yes	

Organization	Yes or No	Question 6 Comment
Group		
pacificorp	Yes	
PJM Interconnection, LLC	Yes	
California Independent System Operator	Yes	
Energy Mark, Inc.	Yes	
Idaho Power Company	Yes	
Independent Electricity System Operator	Yes	
Texas Reliability Entity	Yes	
Kansas City Power & Light	Yes	
Ameren	Yes	
NV Energy	Yes	
MISO	Yes	
MRO NSRF		MRO NSRF AGREES

7. **Based on Industry comments received the SDT made significant clarifying modifications to the Background Document. Do you agree that this document provides sufficient information to justify the rationale used by the SDT in developing the draft standard and provides the industry with sufficient understanding of the issues being addressed by the standard?**

Summary Consideration: Several of the commenters questioned why the formula for FRO was missing. The drafting team explained that this was a problem incurred during the conversion to a pdf file. Once the problem was recognized by NERC, it was immediately fixed during the posting.

A couple of commenters felt that there should be discussion in the Background Document concerning "inertial response". The drafting team stated that they saw a limited role for inertial response in the context of this standard. The standard inherently does not address inertial requirements. It is of interest herein because of its role in determining the post-contingency rate of decline of frequency, as it ultimately impacts the duration of time before the frequency nadir (point C) occurs. The drafting team considered a more elaborate description of inertial response, but believes that it is tangential to the main mission of this standard.

A few of the commenters questioned the use of the largest event in the last 10 years as the criteria for the Eastern Interconnection. The drafting team explained that the results for the current Eastern Interconnection model do not represent observed response adequately. The models for the other Interconnections have a better match. For this reason the drafting team has recommended the largest event in the last ten years be used to provide for an increased reliability margin for the Eastern Interconnection. Further details are provided on pages 52 through 55 of the Frequency Response Initiative paper.

Organization	Yes or No	Question 7 Comment
ACES Power Marketing Standards Collaborators	No	(1) The formula for calculating Frequency Response Obligation appears to be missing on page 23. (2) We are confused by the varying sample rates for the different scan rates in the Definitions of Frequency Values for Frequency Response Calculation table on page 13. It would appear that the time range of values for the average B value varies more than necessary by scan rate. For example, for 2-second scan rates, sampling would start at 20 seconds and end at 52 seconds. However, for the 4-second scan rates, sampling

Organization	Yes or No	Question 7 Comment
		starts at 24 seconds and ends at 48 seconds. Why would it not also cover 20 and 52 seconds for a 4-second scan rate?
Response: Thank you for your comment. (1) This was corrected during the posting. The formula was lost when converting to a pdf file. (2) The SDT has corrected the table.		
Bonneville Power Administration	No	BPA continues to fundamentally disagree with the approach that BAL-003-1 is developing into. Please reference BPA's extensive comments submitted on 12/8/11 for Project 2007-12 Frequency Response found at: http://www.nerc.com/docs/standards/sar/2007-12_comments_received_120911.pdf.
Response: Thank you for your comment. Please refer to our response to your comments dated 12/8/11.		
Keen Resources Asia Ltd.	No	See reply to Question 6. Also, the Background Document is seriously deficient in the discussion of inertial response and therefore how imbalances "cause" frequency deviation. The Background Document is overflowing in discussion of how frequency deviation causes frequency response. In other words, the Background Document is "reactive" and not "proactive". The Background Document lacks any discussion of the internal dynamics of rotating machines, beginning with any definition of what Inertial Response is. Inertial Response is the instantaneous power produced by the lag ("inertia") in the ability of the generator's rotor to slow down to the frequency of the magnetic field in the generator's fixed stator whose frequency is instantaneously lowered by a change in phase angle between voltage and current that is due to a sudden loss of interconnected generation to meet load. Adjustments by voltage response within milliseconds and near the location of the loss are sometimes possible to avert rapid spread of a loss to the frequency of the entire interconnection, and constitute the ongoing work of the Phasor Project long ago initiated by the DOE in the persistent absence of NERC interest or work in this area. NERC and drafting team members under advisement by NERC staff studiously resisted so much as any mention of frequency deviation causation in discussions or in the Background Document. An

Organization	Yes or No	Question 7 Comment
		inexplicable technical Cold War and Berlin Wall built in the 1970s and today separating the DOE Phasor Project from NERC Frequency Response standard development and NERC's so-called Frequency Response "Initiative" needs to be ended and torn down. My document http://www.robertblohm.com/Inertia.doc provides missing technical support and explanation for graphs 1-7 on pages 4-10 of the Background Document, on the basis of an exact understanding of Inertial Response.
Response: Thank you for your comment. The drafting team sees a limited role for inertial response in the context of this standard. The standard inherently does not address inertial requirements. It is of interest herein because of its role in determining the post-contingency rate of decline of frequency, as it ultimately impacts the duration of time before the frequency nadir (point C) occurs. The drafting team considered a more elaborate description of inertial response, but believes that it is tangential to the main mission of this standard.		
Northeast Power Coordinating Council	No	While the discussion of primary frequency response includes inertial energy, the term inertial energy is missing from the definition of "primary frequency response".
Response: Thank you for your comment. The drafting team sees a limited role for inertial response in the context of this standard. The standard inherently does not address inertial requirements. It is of interest herein because of its role in determining the post-contingency rate of decline of frequency, as it ultimately impacts the duration of time before the frequency nadir (point C) occurs. The drafting team considered a more elaborate description of inertial response, but believes that it is tangential to the main mission of this standard.		
Consolidated Edison Co. of NY, Inc.	No	While the discussion of primary frequency response includes inertial energy, the term inertial energy is missing from the definition of "primary frequency response".
Response: Thank you for your comment. The drafting team sees a limited role for inertial response in the context of this standard. The standard inherently does not address inertial requirements. It is of interest herein because of its role in determining the post-contingency rate of decline of frequency, as it ultimately impacts the duration of time before the frequency nadir (point C) occurs. The drafting team considered a more elaborate description of inertial response, but believes that it is tangential to the main mission of this standard.		

Organization	Yes or No	Question 7 Comment
PPL NERC Registered Affiliates	Yes	The PPL Affiliates applaud the SDT for developing this technical justification document.
Response: Thank you for your comment.		
Duke Energy	Yes	Though Duke Energy does not agree with some of the points in the Background Document, it does justify the rationale used by the SDT. Additional comments: at the top of page 23, it states that the basic Frequency Response Obligation is based on non-coincident peak load and generation data reported in FERC Form 714, however the actual calculation is missing and should be based upon the reported MWh, not the peak load as stated. At the bottom of page 23, it states that Attachment A proposes the three options for event criteria, however doesn't clarify why it was chosen that the Eastern Interconnection would be held to the largest event over the last 10 years, while others will be based upon the largest category C loss-of-resource (N-2) event.
Response: Thank you for your comment. (1) This was corrected during the posting. The formula was lost when converting to a pdf file. **(2) The results for the current Eastern Interconnection model do not represent observed response adequately. The models for the other Interconnections have a better match. For this reason the drafting team has recommended the largest event in the last ten years be used to provide for an increased reliability margin for the Eastern Interconnection. Further details are provided on pages 52 through 55 of the Frequency Response Initiative paper.**		
SERC OC Standards Review Group	Yes	We agree with the Duke Energy comments on this question.
Response: Thank you for your comment. (1) This was corrected during the posting. The formula was lost when converting to a pdf file. **(2) The results for the current Eastern Interconnection model do not represent observed response adequately. The models for the other Interconnections have a better match. For this reason the drafting team has recommended the largest event in the last ten years be used to provide for an increased reliability margin for the Eastern Interconnection. Further details are provided on**		

Organization	Yes or No	Question 7 Comment
pages 52 through 55 of the Frequency Response Initiative paper.		
SPP Standards REview Group	Yes	We like the document and feel that it provides a primer on the frequency response standard.The following are typos in and suggested corrections to the document:-The blue lines referenced in the paragraph under Figure 2 on page 14 are green (A) and red (B).-Insert an ‘a’ in the 3rd line of the 2nd paragraph in the Sustained Response section on page 19 between ‘provides’ and ‘greater’.-Insert a ‘for’ in the 2nd line of the 1st paragraph on page 21 between ‘resource’ and ‘all’.-Change ‘provide’ to ‘provided’ in the 3rd line from the bottom line of the 1st paragraph in the Single Event Frequency Response Data section on page 24.-Change the ‘east’ to ‘Eastern Interconnection’ in the 4th line of the 1st paragraph in the Median as the Standard’s Measure of Balancing Authority Performance section on page 27. -Delete the ‘put’ in the 3rd bullet on page 29. Also, replace the ‘put’ in the 5th bullet with ‘gave’.
Response: Thank you for your affirmative response and clarifying comment. The errors you mentioned have been corrected.		
Manitoba Hydro	Yes	No comment.
NREL Transmission and Grid Integration Group	Yes	
Edison Electric Institute	Yes	
pacificorp	Yes	
PJM Interconnection, LLC	Yes	
California Independent System Operator	Yes	
Energy Mark, Inc.	Yes	

Organization	Yes or No	Question 7 Comment
Southern Company	Yes	
Idaho Power Company	Yes	
Texas Reliability Entity	Yes	
Kansas City Power & Light	Yes	
Ameren	Yes	
NV Energy	Yes	
Tucson Electric Power	Yes	
BC Hydro	Yes	
MISO	Yes	
MRO NSRF		MRO NSRF AGREES

8. **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 the issue.**

Summary Consideration: A couple of commenters expressed concern with the fact that the onus for Frequency Response was being put on the BAs who do not own or operate the generators. The drafting team explained that they had heard some of the same concerns, but there are quite a few good reasons why this standard is a good starting point to meet the FERC directives in Order No. 693 (which NERC was given a specific date next year to deliver).

There are several other standards where a similar situation occurs. As you note, many BAs don't own generators. Still, they are responsible for meeting DCS and CPS. The BAs control regulating and contingency reserves to meet the standards. Similarly a TOP is responsible for maintaining voltage even though they may own no capacitor banks or generators to control VArs.

To measure frequency response fairly accurately (one of the 693 directives), you have to monitor the BAs' frequency response (or generator governor response if the standard was generator centric) to about 30 events per year. There are about 140 BAs in North America. There are on the order of 4000 generators that would have to report under a generator-centric standard. How do you verify performance of 120,000 observations annually?

The standard is a backstop standard beyond which we could expect problems during light load conditions for a large contingency. It is not intended to be difficult to meet. As proposed, the standard has a performance obligation about half of what we see today in actual operation. The obligation for the East is on the order of -1000MW/0.1Hz. We have about -2200MW/0.1Hz on average. The standard allows the formation of frequency response sharing groups (similar in concept to DCS' RSGs) and allows obtaining response from other BAs contractually. This means there should be no BAs out of compliance once the standard is in place.

A couple of commenters stated that they thought the standard was confusing. The drafting team stated that they appreciated their concern that the standard is confusing, but the drafting team believed that the proposed standard is as clear as possible while covering all of the issues involved and that based on comments received the industry was not in agreement.

One or two commenters requested clarity on how modifications to the Attachment A could be made and if the FRS Forms 1 and 2 had to be used. The drafting team explained that Attachment A was part of the standard and would have to use the Standard Development Process to make any modifications. The drafting team also stated that the FRS Forms were required to be used in the reporting.

A couple of commenters questioned the use of the Background Document. The drafting team explained that the Background Document was only intended to be used for education and training similar to other training references in the NERC Operating Manual.

Organization	Yes or No	Question 8 Comment
ACES Power Marketing Standards Collaborators	No	(1) We believe that the drafting team work has demonstrated that the standard is unnecessary. The data presented in the posting shows that all of the interconnections easily exceed the required Frequency Response necessary to avoid actuating UFLS relays. Since one of the main purposes of the standard is to provide sufficient Frequency Response, it would seem the purpose is already met without implementing and enforceable standard. So why is a standard needed to compel required Frequency Response if it is already provided? (2) Even though we believe the supporting data for the posting demonstrates the standard is unnecessary, we understand NERC is required by a FERC directive to provide a standard. Given this requirement, we do believe the drafting team has largely provided a reasonable standard and supporting documents that only require a few additional adjustments (see our comments in other questions for these adjustments) to finalize the standard. As a result, we will likely end up supporting the standard once these final adjustments are made.
Response: Thank you for your comment. We agree that the standard meets the primary directive to provide Frequency Response. This standard will set a backstop to assure that Frequency Response will not decline past a "point of no return" **For issues raised in other questions please refer to our response to those questions.**		
Independent Electricity	No	a. We do not support R2 as drafted, specifically the phrase "until directed to change by the ERO". We do not agree that the ERO has any authority to "direct" a BA or FRSG, or

Organization	Yes or No	Question 8 Comment
System Operator		any responsible entities, to make changes to the Frequency Bias Setting or take any operating or operations planning actions. We suggest to replace the word "directed" with "requested". b. In R2, the words "subject to" can be interpreted differently. We suggest to replace them with "in accordance with" to parallel the intent as conveyed in R1. c. We are still concerned with the status of Attachment A, as indicated in our comments submitted under Q4 - that it is unclear if the materials in Attachment A must be adhered to or not. A standard should not have an attachment whose enforcement status is unclear as part of a requirement. d. FRS Forms 1 and 2 are referenced in Attachment 1, which itself has an unclear status on measurability and enforceability. It is also unclear if FRS Forms 1 and 2 must be used to submit the requested data. Collectively, Attachment 1, FRS Form 1 and Form 2 make the standard very confusing as to which parts must be complied with. Much better clarity is needed to clearly convey the standard 's requirements that are measurable, enforceable and must be complied with.
Response: Thank you for your comments, **a) The drafting team believes that the term "direct" is less ambiguous. The drafting team believes that using the term "request" could leave the impression that the action is optional.** **b) The drafting team has adopted your suggested language.** **c) Please refer to the drafting team response to Question #4.** **d) The Attachment is mentioned in the standard requirements and is therefore enforceable. Since the FRS Forms are discussed in the Attachment then they must be used in the calculation process.**		
Bonneville Power Administration	No	BPA continues to fundamentally disagree with the approach that BAL-003-1 is developing into. Please reference BPA's extensive comments submitted on 12/8/11 for Project 2007-12 Frequency Response found at: http://www.nerc.com/docs/standards/sar/2007-12_comments_received_120911.pdf.

Organization	Yes or No	Question 8 Comment
Response: Thank you for your comment. Please refer to the drafting team response to your comments submitted on 12/8/11.		
Exelon Corporation and its affiliates	No	Exelon checked "no" because it does not support the current draft standard. Exelon's position is that efforts to modify frequency monitoring and control should be directed at the existing standards. Since Frequency Bias is already a component of ACE, and ACE performance is tracked by both CPS 1 and CPS 2, it seems evident that NERC already has in place mechanisms for evaluating frequency response. NERC already has in place mechanisms for ensuring sustained frequency response during a contingency, through the Disturbance Control Standard (DCS) and its requirement for the contingent Balancing Authority to deploy resources. Under the current BAL-003-0.1b language, Balancing Authorities are given a consistent means for determining frequency bias, via the minimum requirement of 1% peak generation or 1% peak load. Together with the above references to existing CPS 1 performance measurements, current standards meet the objectives outlined in BAL-003-1. This proposed draft BAL-003-1 complicates the setting of Frequency Bias and attempts to go beyond that purpose into frequency response performance, without clear rules for how to perform. Exelon is also concerned with moving this standard forward while there is an ongoing field trial that could impact whether this standard should be put into place. For example, waivers are in place for CPS 2 for participating Balancing Authorities and there is ongoing effort with the BAAL field trial set of standards that will establish performance metrics around frequency control. As an alternate approach to waiting to move forward on the standard, Exelon recommends the following BAL-003-1 Requirement language: R1. The ERO shall identify up to five [5] system frequency events in each Interconnection that will be included in the Form 1 and 2 data requests for Balancing Authorities by April 30th each year. R2. Each Balancing Authority shall submit the following data to the ERO annually by July 15: R2.1 The total annual net output of generating plants inside the Balancing

Organization	Yes or No	Question 8 Comment
		Authority Area. R2.2 The total annual load with losses inside the Balancing Authority Area. R3. Each Balancing Authority shall calculate its Frequency Response Measure using Forms 1 and 2 as posted by the ERO. (See Attachment A_Form 1 and Form 2) R4. Each Balancing Authority or Frequency Response Sharing Group shall submit Forms 1 and 2 to contacts designated by the ERO before the expiration of ERO established deadlines, which shall be no earlier than 30 days after posting of Forms 1 and 2. R5. The ERO shall post the following information: R5.1. Each Interconnection's Frequency Response Obligation R5.2 Each Balancing Authorities Frequency Response Obligation R5.3 Each Balancing Authorities Frequency Bias Setting R6. Each Balancing Authority shall implement in its ACE equation its ERO established Frequency Bias Setting during the ERO established three-day implementation period. No further adjustments can be implemented outside of the parameters established below in the upcoming year unless a Balancing Authority coordinates with the Regional Entity and the affected Balancing Authorities. R6.1 A Balancing Authority using a fixed Frequency Bias Setting sets its Frequency Bias Setting to the greater of (in absolute value): R6.1.1. The number the BA chooses between 100% and 125% of its Frequency Response Measure as calculated on FRS Form 1. R6.1.2. The Balancing Authorities share of the Interconnection Minimum as determined by the ERO. R6.2 A Balancing Authority using a variable Frequency Bias Setting shall maintain a setting that is:

Organization	Yes or No	Question 8 Comment
		R6.2.1 Less than zero at all times, and R6.2.2 Equal to or greater in magnitude than its Frequency Response Obligations when Frequency varies from 60 Hz by more than +/-0.036 Hz. R7. Each Frequency Response Sharing Group or Balancing Authority that is not a member of a FRSG shall monitor its Frequency Response Obligation and work with generating facilities or demand response resources to provide sufficient Frequency Response to meet the Frequency Response Obligation assigned by the ERO. R8. Each Balancing Authority that adds or removes generation or load, including through the use of dynamic transfers, shall notify the ERO to ensure that any needed adjustments to the Interconnection Frequency Response Obligation or Balancing Authority Frequency Response Obligation and Bias can be calculated. R8.1. The ERO shall notify all affected Balancing Authorities of modifications to the Frequency Response Obligation due to the addition or removal of generation or load. R9. Each Balancing Authority that is performing Overlap Regulation Service shall modify its Frequency Bias Setting in its ACE calculation, in order to represent the Frequency Bias Setting for the combined Balancing Authority Area, to be equivalent of the sum of the Frequency Bias Setting as communicated by the ERO for the participating Balancing Authorities.
Response: Thank you for your comment. ACE, CPS1, CPS2, BAAL and DCS are all standards that measure Secondary Control actions. The inclusion of the Frequency Bias Setting in ACE and these standards make them blind to Primary Frequency Control and thus incapable of helping with the evaluation of Frequency Response (Primary Frequency Control). R1 sets clear rules with respect to how much Frequency Response is required from each BA through the Frequency Response Obligation (FRO) and Frequency Response Measure (FRM). The BAAL Field Trial is investigating issues associated with Secondary Frequency Control only and is not impacted by and has no impact on Primary Frequency Control and BAL-003. The drafting team has considered the suggestions contained in the requirements suggested and has explained in the Background document the reasons for writing the		

Organization	Yes or No	Question 8 Comment
requirements and measures as contained in the draft BAL-003-1.		
Duke Energy	No	Given the FERC deadline approaching for NERC to deliver a Frequency Response standard, Duke Energy supports the adoption of this standard with some reservations. We believe that the proposed standard addresses the FERC directive to NERC, however it also introduces some longer-term issues related to secondary control and related costs that may have not been anticipated by the FERC. To that point, Duke Energy believes that if this standard is adopted, the industry will have the time and opportunity through the NERC standards development process to mitigate some of the concerns presented in our comments."
Response: Thank you for your affirmative response and clarifying comment. The drafting team agrees that there could be some impact on other standards but the implementation period will allow for time to adjust and learn		
Tucson Electric Power	No	I feel that a BA's frequency bias for the upcoming year should not be related to present performance. A BA may have a good response one year and not good response another year and therefore the threshold keeps moving around. I feel it should be related to BA size and therefore somewhat standardized. E.g. a high-performing Balancing Authority will have its frequency bias increased each year due to higher response during the events chosen by the ERO. Conversely, a low-performing Balancing Authority will have its frequency bias reduced each year due to lower response during the events chosen by the ERO.
Response: Thank you for your comment. The drafting team believes that control and frequency performance improve if the Bias Setting and the BA's Frequency Response are as closely matched as possible. Low performing BAs will still have to provide the Interconnection minimum Bias Setting. In an unlikely case where a high performing BA has an internal change that markedly reduces their Frequency Response, there are provisions in the standard's supporting document to accommodate an intra-year change in its Bias Setting.		
New York Independent System Operator	No	In general we support the work of the DT, and the proposal to measure the systems response to frequency events, along with the method to determine the FRO. My

Organization	Yes or No	Question 8 Comment
		outstanding concern is with enforcement on an entity that does not own the resources that provides the frequency response or the lack of obligation for the entity with the information to provide to the BA to make the assessment of expected frequency response. BA's should at a minimum be given assurance that resources will provide data that BA's could use to forecast frequency response and take corrective actions.

Response: Thank you for your comment. We've heard some of the same concerns, but there are quite a few good reasons why this standard is a good starting point to meet the FERC directives in Order No. 693 (which NERC was given a specific date next year to deliver).

There are several other standards where a similar situation occurs. As you note, many BAs don't own generators. Still, they are responsible for meeting DCS and CPS. The BAs control regulating and contingency reserves to meet the standards. Similarly a TOP is responsible for maintaining voltage even though they may own no capacitor banks or generators to control VArs.

To measure frequency response fairly accurately (one of the 693 directives), you have to monitor the BAs' frequency response (or generator governor response if the standard was generator centric) to about 30 events per year. There are about 140 BAs in North America. There are on the order of 4000 generators that would have to report under a generator-centric standard. How do you verify performance of 120,000 observations annually?

MISO has done analysis to find all large frequency events over the past year and how the generators in its footprint performed. It turns out that many of the generators aren't on line for any of the events and only a few of the generators were on line for all large events. So what do you do with generators that are not frequently run? Even if a generator ran 50% of the time, you wouldn't have enough events to do a quality measure in a year.

The standard is a backstop standard beyond which we could expect problems during light load conditions for a large contingency. It is not intended to be difficult to meet. As proposed, the standard has a performance obligation about half of what we see today in actual operation. The obligation for the East is on the order of -1000MW/0.1Hz. We have about -2200MW/0.1Hz on average. The standard allows the formation of frequency response sharing groups (similar in concept to DCS' RSGs) and allows obtaining response from other BAs contractually. This means there should be no BAs out of compliance once the standard is in place.

Finally, to make it a generator standard precluded other solutions (load management, flywheels, market solution, etc.).

Organization	Yes or No	Question 8 Comment
Tri-State Generation and Transmission Assn., Inc.	No	It is our opinion that there has not been enough justification to merit creating a new standard. If additional justification is provided then frequency responsive reserves should be a subset of spinning reserves much like spinning reserves are a subset of operating reserves.
Response: Thank you for your comment. This standard will set a backstop to assure that Frequency Response will not decline past a "point of no return" **This standard does not prescribe a method to provide Frequency Response but does provide for measuring that Frequency Response is delivered.** **Spinning reserve is outside the scope of the industry approved SAR.**		
Puget Sound Energy	No	See comment in response to question 4 above for a discussion of Attachment A concerns. Appendix 1 of the Frequency Response Standard Background Document contains a discussion about why the use of net actual interchange to calculate an entity's Frequency Response Measure might introduce inaccuracies into that calculation. That discussion ends with the following statement: "The frequency response is buried within the typical hour to hour operational cacophony superimposed on actual net interchange values. The choice of metrics will be important to artfully extract frequency response from the noise and other unrepresentative error." Based on these statements, it is very difficult to support the standard's approach to calculating the Frequency Response Measure.At Puget Sound Energy (PSE), though, we believe that there is another factor to add to the "operational cacophony" listed in Appendix 1. PSE is a comparatively small BA with limited internal generation. We are embedded between two of the largest energy exporters in the Western Interconnection and, when there is a frequency event, their response flows through PSE's system. As a result, PSE will experience transmission losses associated with the two BAs' frequency response as it flows through our system. When PSE's frequency response is measured using net actual interchange, these losses obscure, at least in part, our system's

Organization	Yes or No	Question 8 Comment
		frequency response. As a result, we ask the standard drafting team to consider specifying a process that would allow us to propose and use an equivalent measure of frequency response. For example, while we understand the concerns and difficulties associated with measuring frequency response at the generator as the default measure for all BAs, in our case, a choice to use that measurement option might prove to be a more-feasible way to comply with the standard.
Response: Thank you for your comment. Please refer to our response to your comments on Question #4. **Analysis of Field trial data has not shown that this has been a problem.** **The spreadsheets have been designed to allow for adjustment for dynamically scheduled resources located in another BA.**		
PJM Interconnection, LLC	No	See previous comments. Also, this standard should be applicable to GOP's as well as BA's with, at a minimum, the following requirements added: Each GOP shall follow all directives of it's Balancing Authority pertaining to frequency responsive operation, including but not limited to the status, droop & deadband settings of their governors. Each GOP shall provide to their BA the status and droop & deadband settings of their governors, and headroom available to respond to frequency deviations, as requested.
Response: Thank you for your comment. MISO has done analysis to find all large frequency events over the past year and how the generators in its footprint performed. It turns out that many of the generators aren't on line for any of the events and only a few of the generators were on line for all large events. So what do you do with generators that are not frequently run? Even if a generator ran 50% of the time, you wouldn't have enough events to do a quality measure in a year. **Generator verification standards (MOD 27) are scheduled to be revised. The drafting team believes that this will address your second concern**		
PPL NERC Registered	No	The PPL Affiliates are concerned that the document referred to "Attachment A" is

Organization	Yes or No	Question 8 Comment
Affiliates		directly referenced in the proposed standard's requirements but not actually attached to the standard itself as Attachment A. Therefore, it is not clear how the proposed document could be modified in the future. Having such material incorporated into a standard takes away from the open and transparent stakeholder drive process.
Response: Thank you for your comment. The attachment is mentioned in the requirement within the standard and therefore becomes a part of the standard. Any modifications needing to be made to the attachment will have to use the Standards Process.		
Consolidated Edison Co. of NY, Inc.	No	The purpose of BAL-003 was to calculate frequency bias in the ACE equation used in BAL-001. The Standard is currently confusing to understand and it is unclear how the bias is calculated. It is recommended that efforts should be made to clarify the changes, especially Attachment A.
Response: Thank you for your comment. The drafting team appreciates your concern that the standard is confusing, but the drafting team believes that the proposed standard is as clear as possible while covering all of the issues involved. **The drafting team will either develop training materials to provide better understanding for both the FRM and FBS calculations or recommend to the NERC Resources Subcommittee to develop said materials.**		
Northeast Power Coordinating Council	No	The purpose of BAL-003 was to calculate frequency bias in the ACE equation used in BAL-001. The Standard is currently confusing to understand, and it is unclear how the bias is calculated. It is recommended that efforts should be made to clarify the changes, especially in Attachment A.
Response: Thank you for your comment. The drafting team appreciates your concern that the standard is confusing, but the drafting team believes that the proposed standard is as clear as possible while covering all of the issues involved. **The drafting team will either develop training materials to provide better understanding for both the FRM and FBS calculations or recommend to the NERC Resources Subcommittee to develop said materials.**		
Kansas City Power & Light	No	The Standard does not consider instances for smaller BAs that operate generation for peak conditions and acquire energy for most of the operating year.

Organization	Yes or No	Question 8 Comment
Response: Thank you for your comment. The drafting team is unsure of your precise question. However, if your question concerns meeting your performance obligation year around, then the process does allow for mechanisms for a BA to obtain Frequency Response from external resources		
NV Energy	No	While I support the concept of a Frequency Response Standard with minimum performance obligations, this Standard places the entire obligation for performance on the Balancing Authority (and Frequency Reserve Sharing Group). Requirements R2-R4 are properly assigned to the BA, as this is the entity that is responsible for the configuration and parameters in the ACE equation, including the provision of a frequency bias setting. Requirement 1, however, is a performance requirement over which the BA in the Functional Model has virtually no control or ability to influence. Only a Generator Owner or Generator Operator is in a position of control over the performance under this requirement through the operational control and configuration of the responding generating units. In most BA's, the host BA entity also owns a fair amount, even a vast majority in many cases, of the generation within the BA. However, even in the event that the host BA owned 100% of the generation within its metered boundary, it is the action of the entity exercising its GO/GOP function that impacts the frequency response performance within the Balancing Area. Assignment of R1 to the BA is inappropriate from the standpoint that reliability requirements are to be assigned to the Reliability Functions who are capable of causing compliance to occur. A BA has limited ability to influence the outcome of the R1 performance metric. This is unlike other BA-assigned requirements, such as those related to DCS or CPS compliance. For those, the BA does have considerable influence regarding the curtailment of transactions to restore ACE, the direction of plant loading so as to distribute operating reserve, etc. In contrast, performance under this proposed R1 of BAL-003-1 is dependent upon the actions of the GO/GOP in such things as governor settings, generator control system configuration and other operatinal or maintenance activities conducted at the generating plant site. For this reason, it is inappropriate to assign this performance requirement to the BA. Rather, the requirements should be allocated among the GO/GOP's of the on-line generation in some fashion.In further support of

Organization	Yes or No	Question 8 Comment
		this notion, refer to the NERC Functional Model, where it is provided that one of the tasks for Generator Operation is to support Interconnection frequency.

Response: Thank you for your comment. We've heard some of the same concerns, but there are quite a few good reasons why this standard is a good starting point to meet the FERC directives in Order No. 693 (which NERC was given a specific date next year to deliver).

There are several other standards where a similar situation occurs. As you note, many BAs don't own generators. Still, they are responsible for meeting DCS and CPS. The BAs control regulating and contingency reserves to meet the standards. Similarly a TOP is responsible for maintaining voltage even though they may own no capacitor banks or generators to control VArs.

To measure frequency response fairly accurately (one of the 693 directives), you have to monitor the BAs' frequency response (or generator governor response if the standard was generator centric) to about 30 events per year. There are about 140 BAs in North America. There are on the order of 4000 generators that would have to report under a generator-centric standard. How do you verify performance of 120,000 observations annually?

MISO has done analysis to find all large frequency events over the past year and how the generators in its footprint performed. It turns out that many of the generators aren't on line for any of the events and only a few of the generators were on line for all large events. So what do you do with generators that are not frequently run? Even if a generator ran 50% of the time, you wouldn't have enough events to do a quality measure in a year.

The standard is a backstop standard beyond which we could expect problems during light load conditions for a large contingency. It is not intended to be difficult to meet. As proposed, the standard has a performance obligation about half of what we see today in actual operation. The obligation for the East is on the order of -1000MW/0.1Hz. We have about -2200MW/0.1Hz on average. The standard allows the formation of frequency response sharing groups (similar in concept to DCS' RSGs) and allows obtaining response from other BAs contractually. This means there should be no BAs out of compliance once the standard is in place.

Finally, to make it a generator standard precluded other solutions (load management, flywheels, market solution, etc.).

Organization	Yes or No	Question 8 Comment
Arizona Public Service	NO	1. Either do not use C to B Ratio or provide adequate rational for using it. It appears to

Organization	Yes or No	Question 8 Comment
Company		make FRO unnecessarily too conservative and is not justified based upon experience. 2. The VRF is too complicated and hard to understand. It must be either simplified or should be followed by example. 3. The Frequency Response Obligation Methodology on Page 7 of "Procedure" does not show any formula (it is blank).
Response: Thank you for your comment. 1) The rationale can be found beginning on page 14 of the Background document and page 49 of the FRI report. **2) The drafting team is assuming you meant the VSLs. The VSL attempts to correct the VRF based on the BA's size and its impact on the interconnection.** **3) This was corrected during the posting. The problem occurred when the Word document was translated to a pdf file.**		
Energy Mark, Inc.	Yes	Although I am in favor of using linear regression to determine the FRM, the standard using Median is better than not having a standard.
Response: Thank you for your comment. The drafting team thanks you for your affirmative response and clarifying comment.		
Southern Company	Yes	Please refer to comments for question 9.
Response: The drafting team thanks you for your affirmative response and clarifying comment. Please refer to our response for Question #9.		
Manitoba Hydro	Yes	No comment.
NREL Transmission and Grid Integration Group	Yes	
Edison Electric Institute	Yes	
pacificorp	Yes	

Organization	Yes or No	Question 8 Comment
California Independent System Operator	Yes	
Ameren	Yes	
MISO	Yes	
AESO		1. The AESO disagrees with using a non-authoritative background document that has definitions/description of terms used in the reliability standard. It is the opinion of the AESO that these definitions/descriptions need to be authoritative. 2. The AESO has previously submitted comments to the SDT that for the purpose of the FRM calculation, BAs should be able to exclude or include events based on specific conditions or consideration, such as data quality or event suitability (e.g. BA separation from the Interconnection). The revisions made by the SDT do not enable the inclusion of other relevant events in the FRM calcualtion by a BA. The AESO would like to to see these type of events to be permitted in the FRM calculation by a BA.
Response: Thank you for your comment. 1) The Background Document is intended for education and training similar to the other training references in the NERC Operating Manual. **The drafting team believes that any new definitions that are located in the standard will ultimately be placed in the NERC glossary.** **2) The drafting team believes that your concern will be addressed through the process since:** **a) separation events would not be selected,** **b) the median will exclude the outlier situations, and** **c) If the data is corrupted, the FRS Forms allows for exclusion of that event.**		
Public Service Enterprise Group		PSEG entities will vote "Negative" on the standard until this Project 2007-12 achieves the following: 1. It coordinates with Project 2010-14.1 Phase 1 of Balancing Authority Reliability-

Organization	Yes or No	Question 8 Comment
		based Controls Reserves, specifically BAL-012-1, regarding (a) definitions and (b) requirements that address frequency response in both standards. a. Definitions that need to be coordinated: BAL-003-2 - “Frequency Response Obligation” and BAL-012-1 - “Frequency Responsive Reserve.” b. Requirements that need to be coordinated: i. BAL-003-1, per R1, states “Each Frequency Response Sharing Group (FRSG) or Balancing Authority that is not a member of a FRSG shall achieve an annual Frequency Response Measure (FRM) (as calculated and reported in accordance with Attachment A) that is equal to or more negative than its Frequency Response Obligation (FRO) to ensure that sufficient Frequency Response is provided by each FRSG or BA that is not a member of a FRSG to maintain Interconnection Frequency Response equal to or more negative than the Interconnection Frequency Response Obligation.” ii. BAL-012 requires BAs to have sufficient Frequency Responsive Reserves per R6, which requires BAs to “assess, on at least an hourly basis, that it has sufficient Regulating Reserve, Contingency Reserve, and Frequency Responsive Reserve to meet its reserve plan(s) to ensure reliable operation of the Bulk Electric System.” For Frequency Responsive Reserves, R3 in BAL-012-1 requires BAs to develop an annual plan for these reserves.BAs should not be subject to duplicative requirements for frequency response requirements in different standards that are underdevelopment. Only one standard needs to define the frequency response requirements for BAs (we suggest that be BAL-003-1), although other standards, such as BAL-012-1, may reference that obligation. However, this decision should be made by consensus between the two SDTs. 2. It coordinates with Project 2010-14.1 Phase 1 of Balancing Authority Reliability-

Organization	Yes or No	Question 8 Comment
		based Controls Reserves, specifically BAL-012-1, to develop an application guide that would be attached to one of the standards and that could be referenced by each standard. The application guide would include: a. A hypothetical implementation plan for a BA that demonstrates how the BA may meet its Frequency Response Obligation or Frequency Responsive Reserve prior to an event. This is a technical issue and should not be confused with the institutional issue in #3 below. b. An explanation of the relationship between Regulating Reserve, Contingency Reserve, and Frequency Responsive Reserve contained in BAL-012-1 so that potential double counting (and whether that is proper of improper), is addressed. 3. Project 2007-12's "Frequency Response Standard Background Document" dated October, 2012 lists several methods of obtaining Frequency Response. Most of those are extracted below. We have provided questions and commentary that we ask the team to address. a. "Regulation services." This is addressed in BAL-001-0.1a. The purpose of this standard is "To maintain Interconnection STEADY-STATE FREQUENCY within defined limits by balancing real power demand and supply in real-time. How is this related to Frequency Response for a disturbance? (The team may answer this as part of 2.b above.) b. "Through a tariff (e.g. Frequency Response and regulation service). " The team is advised to review the actual pro-forma OATT schedule for Schedule 3 "Regulation and Frequency Response Service" which is specifically limited to services providers that are "capable of providing this service as necessary to follow the moment-by-moment changes in load." Again, how is this related to Frequency Response for a disturbance? (The team may answer this as part of 2.b above.) c. "From generators through an interconnection agreement." The FERC's pro-

Organization	Yes or No	Question 8 Comment
		forma Standard Large Generator Interconnection Agreement (LGIA) per Order 2003 contains no requirement for generators to provide Frequency Response service, and we are not aware on ANY interconnection agreement that does. We ask that the team point to ANY interconnection agreement with such a requirement. Modification of an interconnection agreement to incorporate such a requirement would require the consent of both parties. d. “Contract with an internal resource or loads.”Since Frequency Response service would likely be considered as a necessary service to provide Transmission Service under an OATT, it would require a tariff. What existing tariff applies in the U.S.?The “methods” above that the team has listed have the factual errors described. The standard BAL-003-1 cannot be implemented until the necessary tariffs are developed that permit BAs and FRSGs to contract for Frequency Response services. Once that is done, BAL-003-1 can dictate the performance requirements of a BA or FRSG. o For context, FERC OATT schedules relevant to Frequency Response DO NOT set performance requirements. Schedule 3 (Regulation and Frequency Response Service) sets forth a tariff for the service, while BAL-001-0.1a sets forth performance requirements in aggregate for a BA or RSG. Likewise, Schedule 5 (Operating Reserve - Spinning Reserve Service) and Schedule 6 (Operating Reserve - Supplemental Reserve Service) set tariffs for both services, while BAL-002-1 sets performance requirement. Without an OATT schedule for Frequency Response service, BAs and FRSGs will have no means to contract with generators or loads to provide Frequency Response per BAL-003-1. The team should address this concern.

Response: Thank you for your comment. There is significant coordination between the two drafting teams and this coordination will continue as all standards referenced are posted for comment.

With regard to double jeopardy, both drafting teams have been coordinating to ensure this does not occur.

We believe it is important from a reliability perspective to have a performance based standard. The ultimate need for tariff changes, interconnection agree, etc will be based on a BA’s need to meet the standard.

Organization	Yes or No	Question 8 Comment
Within the measures for R1 and the discussions in the Background document, the drafting team believes that FERC and the industry will be able to develop the changes to tariffs to address your concerns with the BA contracting with sources of Frequency Response to meet its FRO. The BA is also responsible for dispatch levels of resources that provide Frequency Response. Now that Frequency Response has been clearly defined and is able to be measured, sources of Frequency Response for delivery of the service can be developed by the industry. **Once both BAL-003-1 and BAL-012-1 have passed, the drafting team believes it would then be an appropriate time for the members of the two drafting teams to develop an application guide.**		
American Electric Power		There is no leverage for the BA to require the generator to carry their burden of addressing governor settings or droop settings, yet the BA is obligated to meet some performance measures in that regard.This revision adds new performance measure responsibilities on the BA who likely has no direct control over every resource affecting their performance within their footprint. We are not necessarily challenging the performance measures themselves, nor their underlying objectives, however AEP views this as a gap in responsibilities which potentially effects reliability. AEP suggests that GOPs be considered as part of this standard so that their performance can be factored into the process to meet the performance objectives.
Response: **Thank you for your comments. We've heard some of the same concerns, but there are quite a few good reasons why this standard is a good starting point to meet the FERC directives in Order No. 693 (which NERC was given a specific date next year to deliver).** **There are several other standards where a similar situation occurs. As you note, many BAs don't own generators. Still, they are responsible for meeting DCS and CPS. The BAs control regulating and contingency reserves to meet the standards. Similarly a TOP is responsible for maintaining voltage even though they may own no capacitor banks or generators to control VARs.** **To measure frequency response fairly accurately (one of the 693 directives), you have to monitor the BAs' frequency response (or generator governor response if the standard was generator centric) to about 30 events per year. There are about 140 BAs in North America. There are on the order of 4000 generators that would have to report under a generator-centric standard. How do you verify performance of 120,000 observations annually?**		

Organization	Yes or No	Question 8 Comment
MISO has done analysis to find all large frequency events over the past year and how the generators in its footprint performed. It turns out that many of the generators aren't on line for any of the events and only a few of the generators were on line for all large events. So what do you do with generators that are not frequently run? Even if a generator ran 50% of the time, you wouldn't have enough events to do a quality measure in a year. The standard is a backstop standard beyond which we could expect problems during light load conditions for a large contingency. It is not intended to be difficult to meet. As proposed, the standard has a performance obligation about half of what we see today in actual operation. The obligation for the East is on the order of -1000MW/0.1Hz. We have about -2200MW/0.1Hz on average. The standard allows the formation of frequency response sharing groups (similar in concept to DCS' RSGs) and allows obtaining response from other BAs contractually. This means there should be no BAs out of compliance once the standard is in place. Finally, to make it a generator standard precluded other solutions (load management, flywheels, market solution, etc.).		
SPP Standards REview Group		We support the standard as proposed.
Response: The drafting team thanks you for your support.		

9. **Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard BAL-003-1.**

Summary Consideration: A couple of commenter disagreed with the VSLs for Requirement R1. The drafting team explained that the VSLs were a starting point for the enforcement process. The combination of the VSL and VRF is intended to measure a violation's impact on reliability and thus levy an appropriate sanction. Frequency Response is an interconnection-wide resource. The proposed VSLs are intended to put multi-BA Interconnections on the same plain as single-BA Interconnections. Consider a small BA that whose performance is 70% of it's FRO. If all other BAs in the Interconnection are compliant, the small BA's performance has negligible impact on reliability, yet would be sanctioned at the same level as a BA who was responsible for its entire Interconnection. It is not rational to sanction this BA the same as a single BA Interconnection that had insufficient Frequency Response. To do otherwise would treat multi-BA Interconnections tens of times more harshly than single BA Interconnections. However, the drafting team has added language to the requirement to reference the Interconnection Frequency Response Obligation.

One commenter felt that there was an inconsistency between Requirement R4 and Requirement R1 and Attachment A concerning how a BA providing Overlap Regulation Services would calculate its FBS. The drafting team disagreed with their comment. Under the two options in R4 the BAs must still comply with the minimum setting requirements through the calculations performed under R2. In your example, if both BAs turned in FRS Form 1 showing a FBS based on the 100% - 125% minimum these two numbers would be added together for compliance with R4.

One commenter felt that the definition should state that it is a negative value. The drafting team explained that while the desired value would be negative it is mathematically feasible for the actual value to be positive but that value would by definition mean that the entity failed the measurement for Requirement R1.

One commenter disagreed with putting the onus on the BA for providing Frequency Response. The drafting team The drafting team explained that they had heard some of the same concerns, but there are quite a few good reasons why this standard is a good starting point to meet the FERC directives in Order No. 693 (which NERC was given a specific date next year to deliver).

There are several other standards where a similar situation occurs. As you note, many BAs don't own generators. Still, they are responsible for meeting DCS and CPS. The BAs control regulating and contingency reserves to meet the standards. Similarly a TOP is responsible for maintaining voltage even though they may own no capacitor banks or generators to control VArs.

To measure frequency response fairly accurately (one of the 693 directives), you have to monitor the BAs' frequency response (or generator governor response if the standard was generator centric) to about 30 events per year. There are about 140 BAs in North America. There are on the order of 4000 generators that would have to report under a generator-centric standard. How do you verify performance of 120,000 observations annually?

The standard is a backstop standard beyond which we could expect problems during light load conditions for a large contingency. It is not intended to be difficult to meet. As proposed, the standard has a performance obligation about half of what we see today in actual operation. The obligation for the East is on the order of -1000MW/0.1Hz. We have about -2200MW/0.1Hz on average. The standard allows the formation of frequency response sharing groups (similar in concept to DCS' RSGs) and allows obtaining response from other BAs contractually. This means there should be no BAs out of compliance once the standard is in place.

One commenter questioned how the event selection process would work. The drafting team stated that the event selection process was outline in the Procedure for ERO Support of the Frequency Response and Frequency Bias Setting Standard.

Organization	Question 9 Comment
ACES Power Marketing Standards Collaborators	(1) Please strike “that is a member of a multiple BA Interconnection” in R2 and R3. The language makes the requirements difficult to read. We understand this is trying to clarify that these requirements should not apply to BAs such as ERCOT since changing its Frequency Bias Setting does not need to be coordinated with other BAs among other issues, and we do not have an issue with this intent. However, there is an easier way to address this issue without creating a confusing requirement. The SDT should include seeking a variance for the ERCOT area in conjunction with developing the standard. (2) Please strike “in order to represent the Frequency Bias Setting for the combined Balancing Authority Area” in Requirement R4 as it is superfluous and incorrect. First, the two bullets provide the necessary information making the statement unnecessary. Second, the BA Areas are not combined into a single BA Area as implied with the statement “combined Balancing Authority Area”. They are still in fact two distinct BA Areas.

Organization	Question 9 Comment
	(3) The data retention period for R1, R2, R3, and R4 is not consistent with the NERC Rules of Procedure. Section 3.1.4.2 of Appendix 4C - Compliance Monitoring and Enforcement Program states that the compliance audit will cover the period from the day after the last compliance audit to the end date of the current compliance audit. The data retention section states that data shall be kept for the current calendar year plus the three previous calendar years. This could be up to four years which exceeds the BA audit period of three years. It is unnecessary for a BA to maintain evidence that was already verified in a prior audit. We recommend changing the evidence retention period to three years. (4) Has the drafting team coordinated the addition of the Frequency Response Sharing Group (FRSG) with the Functional Model Working Group and the NERC staff responsible for organizational registration? If not, please do so as NERC will need to be willing to register entities as a FRSG if it is to be utilized. Furthermore, the Functional Model Working Group should document the purpose and intent of the FRSG .(5) We disagree with the VSLs for R1. The VSLs are structured such that a BA's or FRSG's violation is dependent upon the rest of the interconnection to determine the severity level of the violation. If the BAs collectively fail to achieve the Interconnection Frequency Response obligation, a 2% violation of the Frequency Response Measure jumps from a Lower VSL to a High VSL. This should never be the case. No violation by a registered entity should become potentially more or less severe based on the violation of another entity. We encourage the drafting team to work with NERC Legal department in reviewing this VSL further as FERC has already allowed ISO/RTO violations investigation to draw in third parties that potentially contributed to the ISO/RTO violation to ensure the appropriate party is fined. The principal is similar here in ensuring the appropriate BA is fined for its violation not the violations/failures of other BAs. The background document mentions on page 31 that the motivation for structuring the VSL in this manner was to prevent BAs in multiple BA interconnections from being sanctioned disproportionately. We appreciate the draftingteam considering this issue but believe there is a simpler solution. Four VSLs could simply be written based on the percentage the BA misses its own Frequency Response Obligation. Furthermore, the compliance enforcement process already considers if the violation impacted reliability when assessing a sanction

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	.(6) The Frequency Response Obligation (FRO) term is used inconsistently with the definition in the VSLs for R1. The first part of each BA implies that the Interconnection has an FRO. However, the definition specifically states that FRO is the BA's "share of the required Frequency Response". It does not apply to the Interconnection. How can the Interconnection have a share of the required frequency response? A new term may need to be defined for the Interconnection. (7) The implementation plan still references Requirement R5. There is no such requirement .(8) Requirement R1 is not consistent with the recent direction NERC has taken to refocus on reliability and looking forward during compliance audits rather than backwards. For instance, NERC has proposed monitoring internal controls of registered entities because this will provide a reasonable assurance that the registered entity is prepared to comply in the future. Current compliance audits focus mostly on past performance and provide no indication of future reliability. How does Requirement R1 support this forward looking vision when it is a lagging indicator that looks at historical performance? (9) Requirement R4 appears to be inconsistent with Requirement R1 and Attachment A. On page 3, Attachment A states the BA shall set its Frequency Bias Setting to 100% to 125% of it Frequency Response Measure or Interconnection Minimum. However, Requirement R4 states that the BA providing Overlap Regulation Service shall set its Frequency Bias Setting to the sum of its Frequency Bias Settings on FRS Form 1 and FRS Form 2 of its own BA and the BA to which its provides Overlap Regulation Service. For simplicity let's call the BA providing Overlap Regulation Service BA X and the BA receiving the service BA Y. Why would the BA X not set its Frequency Bias Setting to 100% to 125% of the sum of BA X's and BA Y's Frequency Response Measure? This would make Requirement R4 parallel with R2. (10) We do not understand the difference between the two bullets in Requirement R4. They appear to say essentially the same thing and the background document provides no discussion to distinguish their differences. Please provide further explanation.

Response: Thank you for your comments.

(1) The proposed variance alternative could create unnecessary work for different organizations.
(2) The proposed elimination of words could help but, the elimination could bring more questions than benefits.

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(3) The drafting team believes that the language proposed in the draft standard is typical of other standards and is not in violation of anything. (4) The drafting team is coordinating as you stated. (5) VSLs are a starting point for the enforcement process. The combination of the VSL and VRF is intended to measure a violation's impact on reliability and thus levy an appropriate sanction. Frequency Response is an interconnection-wide resource. The proposed VSLs are intended to put multi-BA Interconnections on the same plain as single-BA Interconnections. Consider a small BA that whose performance is 70% of it's FRO. If all other BAs in the Interconnection are compliant, the small BA's performance has negligible impact on reliability, yet would be sanctioned at the same level as a BA who was responsible for its entire Interconnection. It is not rational to sanction this BA the same as a single BA Interconnection that had insufficient Frequency Response. To do otherwise would treat multi-BA Interconnections tens of times more harshly than single BA Interconnections. However, the drafting team has added language to the requirement to reference the Interconnection Frequency Response Obligation. (6) The drafting team has clarified the VSL. (7) The drafting team has corrected the Implementation Plan. (8) The drafting team disagrees. The drafting team believes that this is a performance based standard similar to BAL-001 CPS and BAL-002 DCS requirements. With regards to "internal controls" the drafting team believes that this is an enforcement activity not a standards activity. (9) The drafting team disagrees with your comment. Under the two options in R4 the BAs must still comply with the minimum setting requirements through the calculations performed under R2. In your example, if both BAs turned in FRS Form 1 showing a FBS based on the 100% - 125% minimum these two numbers would be added together for compliance with R4. (10) Under the first bullet, two BAs have submitted two FRS Form 1 document in accordance with R1. Under the second bullet, one entity has turned in a single FRS Form 1 with all information for the two BAs combined.	
Keen Resources Asia Ltd.	A probabilistic/statistical basis needs to be developed for the FRM that assesses for usage of frequency response (causation of frequency error) and not just for provision of it. This would also overcome NERC's singular focus on reaction, and NERC's color-blindness to proaction, pointed out in my reply to question 7.
Response: Thank you for your comment. As part of the ongoing evaluation of Frequency Response this may be considered.	
SPP Standards REview Group	Additional typos:Change the ')' to a '(' in the 4th line of M1 of the standard.No further comment

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Response: Thank you for your comment. This has been corrected.	
Arizona Public Service Company	As mentioned in Item 8 above, the VRF language is too complicated and hard to follow. Even though the VRF poll is non binding, it needs to be clear and simple enough to be understood.
Response: Thank you for your comments. The drafting team is assuming you mean the VSL. VSLs are a starting point for the enforcement process. The combination of the VSL and VRF is intended to measure a violation's impact on reliability and thus levy an appropriate sanction. Frequency Response is an interconnection-wide resource. The proposed VSLs are intended to put multi-BA Interconnections on the same plain as single-BA Interconnections. Consider a small BA that whose performance is 70% of it's FRO. If all other BAs in the Interconnection are compliant, the small BA's performance has negligible impact on reliability, yet would be sanctioned at the same level as a BA who was responsible for its entire Interconnection. It is not rational to sanction this BA the same as a single BA Interconnection that had insufficient Frequency Response. To do otherwise would treat multi-BA Interconnections tens of times more harshly than single BA Interconnections. However, the drafting team has added language to the requirement to reference the Interconnection Frequency Response Obligation.	
BC Hydro	BC Hydro respectfully submits these additional comments/observations: 1.The proposed standard seems to indicate that it is applicable to the identified responsible entities at all times. There might be circumstances where a BA that belongs to a multiple-BA Interconnection became isolated and has to operate in restorative mode which might require adjusting the frequency bias to a value less negative than the minimum FBS setting value in order to follow the much reduced load/generation level in the area. We suggest adding some language in either the Applicability section or in individual Requirements to recognize these circumstances. 2.Effective Dates: the proposed standard specifies a fixed period (12-month or 24-month) following Regulatory Approval which may fall in the middle of the year while the calculation and implementation are performed on an annual basis. Does this represent any conflicts? 3.The proposed standard does not clearly specify whether a BA must chose between using fixed bias or variable bias for the entire year. Should BAs be allowed to switched back and forth between the two methods? If yes, more details may be needed to account for the FRM and minimum FBS. 4.The proposed standard does not clearly specify whether a BA can be part of a FRSG for only part

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	of the year or must be the whole year 5.The definition of FRO, FRM, FBS, etc. should all include language to indicate the “negative” nature of the value. 6.Measure M2 should have “and uses a fixed bias” added for clarity purpose. 7.In the Additional Compliance Information section of the proposed standard the following info still exists: For Interconnections that are also Balancing Authorities, Tie Line Bias control and fFlat Ffrequency control are equivalent and either is acceptable. Since all reference to AGC Modes have been removed from the Requirements, this additional info should also be removed.
Response: Thank you for your comments. **(1) The drafting team does not believe that there is any difference between adherence to the current standard and the proposed standard. With regard to islanded operations, the drafting team believes that other standards prevail under those conditions.** **(2) The timelines are not requirements and may be adjusted to meet the annual calculation process proposed by the standard.** **(3) The drafting team believes the standard as drafted, allows for two types of bias, fixed and variable. A fixed bias is a single number for the entire period. A number that changes within the period is a variable bias and is subject to Requirement R3.** **(4) FRS Form 1 and 2 allows for the transfer of Frequency Response on a per event basis.** **(5) While the desired value of the FRM would be negative it is mathematically feasible for the actual value to be positive but that value would by definition mean that the entity failed the measurement for Requirement R1. The FBS definition states that it is an inverse contribution to the interconnection frequency; therefore the definition does not need to reference a negative value. The FRO will be an allocation of the IFRO whose calculation methodology will provide a negative number. The allocation of a negative number will result in a negative number. For these reasons the SDT did not modify the definitions.** **(6) Requirement R2 is only applicable to entity’s using a fixed bias therefore Measure M2 only applies to those utilizing a fixed bias.** **(7) The proposed elimination of words could help but, the elimination could bring up more questions than benefits.**	
Edison Electric Institute	EEI supports the efforts and improvements made by the Standards Drafting Team (SDT) in the latest version of BAL-003 and believe those changes have been responsive to the directives in Order 693. However, we recognizes that the Industry has struggled with this standard and remains split as to how best to respond to those directives and in some cases there are those who question

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	whether a standard is even necessary. Given the many open issues and the concerns expressed by stakeholders we anticipate that this standard will once again fail to achieve sufficient support to gain approval. Should the Standard fail to achieve ballet approval, it is our hope that NERC Staff and the NERC Board of Trustees will allow the SDT a little more time to resolve any final issues that have been identified in this latest ballet. Although we recognize that May 31, 2013 does not leave the ERO with a lot of time to comply with this FERC imposed deadline, we still remain confident that given the progress made by the SDT a standard, which is acceptable to the Industry, is still possible. To the extent EEI can help, we are committed to working with member companies to communicate the issues and exchange insights from the SDT to help as we can to achieve a positive outcome.
Response: Thank you for your comment and support.	
Manitoba Hydro	Purpose: Is the reference to 'Interconnection Frequency' supposed to be 'Frequency Response'? This would be consistent with later wording in the standard. R1: (1) The acronym 'FRO' is used inconsistently within the document. (2) The phrase "to ensure that sufficient Frequency Response ..." should be separated from the requirement as it is (i) not descriptive of the required actions (ii) redundant with the stated purpose at the beginning of the standard. In general, such a drafting technique should be avoided as it may allow Responsible Entities to argue that a violation has not occurred where the specific action that is described has not been taken, but the purpose referenced in the requirement has been met. M1: The reference to 'documented formula' is not clear. Does this imply that the FRSG or BA have a record of their calculation? In addition, there is a typo, a random ')' after FRM. M2: Should include the words 'and uses a fixed Frequency Bias Setting...' after overlap Regulation

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	Service to make the wording consistent within the Requirement. M3: The wording of this measure switches tenses between 'is' and 'was'. For consistency, we suggest that this be corrected. NERC Glossary definition of an FRSG is a group of BAs that collectively maintain, allocate and supply operating resources required to jointly meet the sum of the Frequency Response Obligations of its members. No mention is made of the agreement including the sharing or delegation of responsibility related to FRM. Accordingly, the standard should only reference a BA being able to delegate responsibility to an FRSG if the RSG Agreement allows for such delegation. Data Retention 1.3. (1) As the standard is currently drafted, both the BA and the FRSG would be required to retain data or evidence to show compliance with requirements R1 and M1. It is unclear whether this is the intention, or whether it would be acceptable that just one or the other would maintain such records .(2) In the third paragraph, it should be clarified who is required to keep information related to non compliance if the BA belongs to an FRSG - the BA or the FRSG or both.

Response: Thank you for your comments. The drafting team believes that the purpose statement is correct as written. The standard is for both Frequency Response and Frequency Bias Setting both of which support Interconnection Frequency.

(1) The drafting team corrected the identified FRO inconsistencies within the documents.
(2) The drafting team was advised by NERC staff to include the language you are referencing.
(3) M1 – Yes the entity must have a record of their calculation. The typo has been fixed.
M2 - Requirement R2 is only applicable to entity's using a fixed bias therefore Measure M2 only applies to those utilizing a fixed bias.
M3 – The drafting team corrected the use of "is" in the last line of the measure.
(4) The drafting team believes that any agreement between members of a RSG is an issue that the RSG would handle. We have a created the FRSG to address the concerns that an existing RSG may or may not be a FRSG.

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Data Retention **(1) Both the BA and FRSG must maintain data. At a minimum the BA needs data to document its bias setting obligation. In addition, the BAs data may be needed to demonstrate FRSG performance.** **(2) The drafting team believes that the language is clear; the entity that is found non-compliant would be the entity that would be required to keep the data.**	
JEA	R1 places the burden for compliance on the BA but the BA does not control generation assets and should not be solely responsible for maintaining frequency response. While the standard can still define the amount of Frequency Response for each BA, there needs to be an obligation on the GO/GOP to provide that service as directed by the BA and they should also be held accountable for compliance. Finally, we do not believe that a sufficient study has been conducted to determine the impact of this standard. We are concerned that a substantial number of compliance issues could result and that the resulting cost to maintain compliance could be excessive and we suggest it be put through the Cost Effective Analysis Process (CEAP). We suggest that the proposed values be evaluated on a sample size within each region to determine the number of compliance issues and for those issues that are found determine what the BA would have to do be compliant.
Response: **Thank you for your comments. We've heard some of the same concerns, but there are quite a few good reasons why this standard is a good starting point to meet the FERC directives in Order No. 693 (which NERC was given a specific date next year to deliver).** **There are several other standards where a similar situation occurs. As you note, many BAs don't own generators. Still, they are responsible for meeting DCS and CPS. The BAs control regulating and contingency reserves to meet the standards. Similarly a TOP is responsible for maintaining voltage even though they may own no capacitor banks or generators to control VArs.** **To measure frequency response fairly accurately (one of the 693 directives), you have to monitor the BAs' frequency response (or generator governor response if the standard was generator centric) to about 30 events per year. There are about 140 BAs in North America. There are on the order of 4000 generators that would have to report under a generator-centric standard. How do you verify performance of 120,000 observations annually?**	

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MISO has done analysis to find all large frequency events over the past year and how the generators in its footprint performed. It turns out that many of the generators aren't on line for any of the events and only a few of the generators were on line for all large events. So what do you do with generators that are not frequently run? Even if a generator ran 50% of the time, you wouldn't have enough events to do a quality measure in a year. The standard is a backstop standard beyond which we could expect problems during light load conditions for a large contingency. It is not intended to be difficult to meet. As proposed, the standard has a performance obligation about half of what we see today in actual operation. The obligation for the East is on the order of -1000MW/0.1Hz. We have about -2200MW/0.1Hz on average. The standard allows the formation of frequency response sharing groups (similar in concept to DCS' RSGs) and allows obtaining response from other BAs contractually. This means there should be no BAs out of compliance once the standard is in place. Finally, to make it a generator standard precluded other solutions (load management, flywheels, market solution, etc.). The SDT does not believe that there is a need to perform a "cost analysis". The numbers are lower than the numbers we are presently seeing.	
Los Angeles Department of Water and Power	Spinning reserves are intended to support the interconnection response to the loss of a resource. If BAL-003-1 is adopted through this Project, the LADWP recommends that the spinning reserve requirements of BAL-002-0.1b and BAL-STD-002-0 be removed, as the Spinning reserve requirement would require utilities to reserve resources in excess of the reserves required in BAL-003-1. LADWP recognizes that this recommendation may be handled through a separate NERC Project, but wanted to submit this comment to bring light to this potential conflict in Reliability Standards.
Response: Thank you for the observation.	
Tacoma Power	The addition to the Frequency Bias Setting definition of "and discourage response withdrawal through secondary control systems" seems incomplete. Tacoma Power does not see anything in the standard that addresses (or measures) how a frequency bias setting will discourage response withdrawal through secondary systems. This should either be more fully addressed or removed.

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Response: The FRI Report and the Background Documents contain explanations on this issue.	
SERC OC Standards Review Group	The comments expressed herein represent a consensus of the views of the above namedmembers of the SERC OC Standards Review Group only and should not be construed as theposition of SERC Reliability Corporation, its board, or its officers.
Response: Thank you for the clarification	
Duke Energy	The concern raised in Duke Energy's comments in item 4 will not be a factor for a few years, but will be an issue as more and more BAs are in the position of their FRM being better than the Interconnection Minimum allocation. We believe that the language that we proposed for calculating the minimum FBS in a multiple-BA Interconnection allows for the proper incentives for BAs to maintain FRM much better than required, and allows for comparable measurement of secondary control performance between similarly-sized BAs, while presenting no risk to reliability.
Response: Thank you for your comment. The industry will utilize information from the process related to this standard to make future decisions. Also, please refer to our response to your Question #4 comment.	
Puget Sound Energy	The definition of "Frequency Response Obligation" applies only to a Balancing Authority. However, requirement R1 applies to both FRSGs and BAs and includes a Frequency Response Obligation that applies to each of those entities. As a result, the definition must also address an FRSG's Frequency Response Obligation. The acronym for Balancing Authority is not included following the first reference to the term in requirement R1 (looks like an inadvertent deletion). Requirement R1 states that an entity "... shall achieve an annual Frequency Response Measure (FRM)...." However, the definition of Frequency Response Measure already includes the concept of annual. As a result, the word "annual" should be removed from the requirement. Requirement R1 includes the language "... to ensure that sufficient Frequency Response is provided

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	by each FRSG or BA that is not a member of a FRSG to maintain Interconnection Frequency Response equal to or more negative than the Interconnection Frequency Response Obligation." This language is a purpose statement rather than a requirement applicable to a FRSG or a BA and should be excluded from the requirement. So long as an FRSG or BA achieves the FRM calculated in accordance with Attachment A, it has done everything necessary to comply with the standard. There are discrepancies between the implementation plan and the proposed standard:- The definitions of "Frequency Response Measure" and "Frequency Response Obligation" in the Implementation Plan are different from those proposed in the draft standard.- The Implementation Plan references "Reserve Sharing Group" rather than "Frequency Response Sharing Group".- The Implementation Plan does not include a definition for the term "Frequency Response Sharing Group".- The Implementation Plan continues to reference R5 in the discussion of the standard's proposed effective date. The annual process dates listed on page 32 of the Background document appear to be inconsistent with those listed in Attachment A.
Responses: Thank you for your comments. **The calculation of FRO is done at the individual BA level. Those BAs that are part of a FRSG must sum their individual FROs to determine the FRSG FRO. This is clearly stated in Attachment A.** **The drafting team corrected this oversight.** **The drafting team disagrees that the term "annual" should be removed as it provides greater clarity as written.** **The drafting team was advised by NERC staff to include the language you are referencing.** **The drafting team has corrected the Implementation Plan.** **The dates are not firm dates but are examples for the process.**	
California Independent System Operator	The ISO supports the development of BAL-003-1 and would like to offer the following comments/suggestions: (1) Some BAs may have to develop a new Ancillary Service product to ensure that its FRO can be met and believes that 12 months after FERC's approval may not provide adequate time to

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	stakeholder and modify market software applications. The ISO suggest increasing the implementation timeline by at least one more year. (2) If the implementation timeline cannot be changed, then the ISO suggests that compliance should be waived for the first year of operation under BAL-003-1. (3) Some BAs may elect to procure a portion of its FRO through bilateral agreements for certain hours (e.g. off-peak) with a neighboring BA. Since a contingency could be in a BA other than the two BAs under a bilateral agreement, the standard or background document needs to clarify the duration of frequency response so that transmission reservation is not a requirement for frequency response. The ISO believes that the BA experiencing the contingency should have adequate arrangements in place to deal with internal contingencies.
Response: Thank you for your comments. **(1) The implementation date for Requirement R1 is 24 months after FERC approval, not 12 months. We believe that this would provide ample time.** **(2) See (1) above.** **(3) The measurement period is 20 to 52 seconds after the beginning of the event. Additionally, there is no mention of transmission requirements for purchase or delivery of Frequency Response.**	
Portland General Electric Company	The issue with proposed Reliability Standard BAL-003-1, requirement R1, is that the Annual Frequency Response Measure (FRM) is determined after the fact with an entity unable to identify or monitor compliance (on non-compliance) along the way. Also, the requirement seems to go the opposite direction of NERC's risk based initiatives where collecting historic compliance information become unsustainable.
Response: Thank you for your comments. **(1) The identification and posting of events will occur on a quarterly basis as stated in the Procedure Document. This will allow BAs to monitor their compliance.** **(2) The SDT believes that this is a performance based standard similar to BAL-001 CPS and BAL-002 DCS requirements.**	

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MRO NSRF	The MRO NSRF is concerned with the drafting team's exclusion of single Balancing Authority Interconnections from compliance with Requirement R2. To ensure a consistent approach in the application of BAL-003-1, recommend R2 be revised as follows: R2). Each Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting shall implement the Frequency Bias Setting determined subject to Attachment A, as validated by the ERO, into its Area Control Error (ACE) calculation ...
Response: Based on the comment rather than the proposed language the drafting team is providing the following response. The drafting team discussed the applicability of bias requirements to single BA Interconnections extensively. The consensus of the FRSDT was that single BA Interconnections inherently have strong incentives to accurately represent their frequency response characteristic. Any adverse consequences of misrepresenting the frequency response characteristic will be borne solely by that BA and cannot affect other BAs in other Interconnections adversely.	
Southern Company	The organization selecting events must ensure that the change in frequency is outside the normal dead-band of generator governors. Many of the events selected in the past have not been outside the dead-band and therefore, the frequency response was much less than expected. Southern Company proposes .07 which is consistant with WECC.
Response: Thank you for your comments. The drafting team has created a Procedure Document that details the event selection criteria for each Interconnection. This should alleviate the concern of smaller events being selected.	
Independent Electricity System Operator	The proposed effective date for this standard conflicts with Ontario regulatory practice respecting the effective date of implementing approved standards. It is suggested that this conflict be removed by appending to each of Section A1.3 and A1.4, after "months after applicable regulatory approval", of the standard to the following effect:", or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities."The same change should be made to the two bullets in the proposed Implementation Plan.
Response: The drafting team appreciates your comment. However, this language is required to be used by the drafting team with	

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the only modification allowed to be the number of months prior to implementation.	
Northeast Power Coordinating Council	The VSL's refer to the FRM (Frequency Response Measure). If that is the intent of the Standard, then GO's and GOP's should be included in the applicability since they are the entities responding to the AGC signals. If the intent is the FRO (Frequency Response Obligation) only, then the VSL's should be updated.
Response: The FRM is not intended to measure response to AGC signals but is intended to measure response to frequency changes. Therefore, the drafting team does not believe that any modification is warranted.	
Consolidated Edison Co. of NY, Inc.	The VSL's refer to the FRM (Frequency Response Measure). If that is the intent of the Standard, then GO's and GOP's should be included in the applicability since they are the entities responding to the AGC signals. If the intent is the FRO (Frequency Response Obligation) only, then the VSL's should be updated.
Response: The FRM is not intended to measure response to AGC signals but is intended to measure response to frequency changes. Therefore, the SDT does not believe that any modification is warranted.	
Tucson Electric Power	This is an important task and the efforts of the drafting team are appreciated.
Response: Thank you for the recognition.	
The United Illuminating Company	UI believes the VRF should be High. The VRF justification for Medium is that the prior year's bias setting would exist in the control system so the impact would not cause a Cascade. UI thinks that is an adjustment factor that is applied after non-compliance is determined. Not having settings is likely to cause cascade so the VRF is High.
Response: The drafting team reviewed the definition for the VRF levels and believes that the appropriate levels were used for each requirement.	
Tri-State Generation and	We are concerned with the tariff implictations associated with this standard. Will this standard

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Transmission Assn., Inc.	create the need for an additional ancillary service under the FERC pro forma OATT?
Response: The drafting team believes that your comment is possible but does not think that it is in the scope of NERC to make changes to the FERC pro forma OATT.	
NREL Transmission and Grid Integration Group	We commend the drafting team for a rigorous approach to this new and important standard. Being observers who have a strong interest in this standard as it applies to much of the research that we do, but not stakeholders of the ultimate standard, we submit our overall comments as recommendations here. We believe there are a few potential issues, that may at least need more thought before going forward. The first is the credit for LR. (1) Overfrequency can be an issue: using ERCOT as an example, with -282 MW/0.1Hz response and 1400 MW of LR all responsive at 59.7 Hz, if just meeting FRO requirements, the 1400MW LR can all be triggered with a loss of (282*3=) 846MW, causing (1400-846=)554MW of overgeneration. This can be exacerbated by further increases of LR without recognition of the triggering frequency, and the disconnect between BA and interconnection in the other interconnections. (2) With crediting LR toward the Interconnection, it will not give incentive toward BAs to provide it. We believe the LR should contribute to the BA FRO rather than discount the IFRO. (3) There is no requirement for frequency response capacity (ie MW) available to provide the FR. This is a nonissue in today's world with the amount of spinning reserve already available, but the issue could be apparent on future systems with increased reserve sharing, or reserve capacity from resources that operate in modes which do not provide frequency response. The European Interconnection requirement has two intentions: a 3,000 MW capacity requirement and a 1,500 MW/0.1Hz FRO requirement that is allocated out to its Transmission System Operators. This could solve the issue with LR and generators, where LR is in MW and generation governing is in MW/0.1Hz. (4) It is likely, and from our understanding is true in some areas like ERCOT, that the LR is selected based on market solutions, and may not be available all times of the year. This is another reason why the LR should contribute to the BA FRO rather than discount the IFRO. (5) It may be beneficial to guide frequency settings for LR or even multiple settings to mimic a

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	droop curve for LR. Other potential issues not related to the LR. We think the SDT has done an outstanding job on reviewing the data sets and determining statistically based values to better account for different factors that may affect minimum frequency levels. We agree that there are current issues in the primary governing response, but that there may be a disconnect in fixing those issues with the static values. We also agree that there is not an easy solution. In specific: (a) The static CB ratio might not incentivize BAs to improve response with increased inertia or faster responding governing response. (b) The static withdrawal BC'adj may not incentivize BAs to improve their governing response and limit their withdrawal. Improved technology may allow for better measurement to account for these issues dynamically rather than using static numbers. Guidance on increasing inertia, increasing governing speed, and reducing withdrawal should be considered by stakeholders. We thank NERC and the SDT for the opportunity to provide comments on this important standard.
Response: Thank you for your comments. **(1) The standard as presently written addresses both over and under frequency events.** **(2) The credit given for LCR is based on numbers provided by the interconnection. The utilization of load by any individual BA will be included in the calculation of their FRM through the Net Actual Interchange term rather than the IFRO.** **(3) Thank you for your comment.** **(4) Please refer to our response to (2) above.** **(5) Thank you for your comment. As more information is gained through implementation of this standard modifications based on this information will be possible.**	
Ameren	While we support this draft, we believe that this might only be a starting point and as additional knowledge and experience is gained through the implementation of this standard and other efforts such as the FRI, that the improvements can be embraced by all parties, even if those improvements result in relaxed requirements.
Response: Thank you for your comments. The NERC process allows for adjustments and improvements for both its thresholds and	

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methodologies when operational experience has been gained.	
Xcel Energy	Xcel Energy supports this proposed revision to the standard as a first step and suggests that after operating for a couple of years under the revised standard, that NERC initiates a more complete study to support any modifications to the standard.
Response: Thank you for your comment. The drafting team agrees.	

END OF REPORT