Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. The Standards Committee approved the SAR for posting on November 21, 2006
2. SAR posted for comments on November 29, 2006.
3. The Standards Committee appointed a SAR Drafting team on January 11, 2007.
4. SAR Drafting Team responds to comments, revises SAR and posts for comments on February 7, 2007.
5. SAR Drafting Team responds to comments on April 20, 2007.
6. Standards Committee approves development of Standard on April 10, 2007.
7. The Standards Committee appointed the Standard Drafting Team on April 10, 2007.
8. The Standards Drafting Team posted draft performance characteristics for comment on July 2, 2008.
9. Standards Drafting Team responds to comments, revises standard and posts for comments on April 15, 2009.

Proposed Action Plan and Description of Current Draft:

This is the second posting of the proposed standard (the first posting was proposed common continent-wide performance characteristics as a directive to the Regional Entities to develop regional standards) for a 30 day comment period, from April 15 – May 14, 2009.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Respond to comments on the second posting and post revised standard for a 30 day comment period.	July 7, 2009
2. Respond to comments on the draft of the proposed standard and implementation plan.	September 14, 2009
3. Obtain the Standards Committee's approval to move the standard forward to balloting.	September 16, 2009
4. Post the standard and implementation plan for a 30-day pre-ballot review.	October 1, 2009
5. Conduct an initial ballot for ten days.	November 15, 2009
6. Respond to comments submitted with the initial ballot.	November 30, 2009
7. Conduct a recirculation ballot for ten days.	December 15, 2009
8. BOT adoption.	

A. Introduction

1. **Title:** Automatic Underfrequency Load Shedding
2. **Number:** PRC-006-01
3. **Purpose:** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency and assist recovery of frequency following underfrequency events.
4. **Applicability:**
   - **4.1.** Planning Coordinators
   - **4.2.** Distribution Providers
   - **4.3.** Transmission Owners with end-use Load connected to their Facilities where such end use load is not part of a Distribution Provider's load (6/10 – the team conducted an informal poll and determined that the majority of the team feels that eliminating the TO from applicability is appropriate because the concern driving to include the TO with the qualifier was to fix a registration issue – those TO's w end use load that are not registered as Distribution Providers. However, the TO might have to remain in the applicability if the TO is to provide data in requirement R9).
   - ~~Generator Owners~~
5. **(Proposed) Effective Date:** TBD

B. Requirements

R1. Each Planning Coordinator shall join a group consisting of all the Planning Coordinators within the region for each of the regions in which it performs the Planning Coordinator function.

Each Planning Coordinator shall design an underfrequency load shedding program in collaboration with all the Planning Coordinators within the region in which it performs the Planning Coordinator function that will result in one program for the region. consistent application across the region

R2. Each group of Planning Coordinators shall design an underfrequency load shedding program for ~~consistent~~ application across the region.

R3. Each group of Planning Coordinators shall develop criteria, considering historical events and system studies, to select portions of the Bulk Electric System (BES) that may form islands.

R4. Each group of Planning Coordinators shall develop a procedure for coordinating with groups of Planning Coordinators in neighboring regions within an interconnection to identify and reach agreement on islands between its region and neighboring regions within the interconnection. The procedure shall identify how the neighboring entities will assist in the UFLS assessments and document concurrence of assessment results.

R5. Each group of Planning Coordinators shall identify an island(s) as a basis for designing a UFLS program. The identified island(s) shall include:

- Those islands selected by applying the criteria in Requirement R3, if any.
- Any portions of the BES that are designed to be detached from the interconnection (planned islands) as a result of the operation of a relay scheme.
- Interregional islands agreed on by the Planning Coordinators.
- Any other islands necessary to ensure that all portions of the region's BES are included in at least one island.

R6. Each group of Planning Coordinators shall specify the technical design parameters of the underfrequency load shedding program required to meet the following performance characteristics in simulations of underfrequency conditions resulting from an imbalance scenario where an imbalance = [(load — actual generation output) / (load)] of up to 25 percent within the identified island(s):

~~R6.1.~~6.1. Arrest frequency decline at no less than 58.0 Hz.

~~R6.2.~~6.2. Frequency shall not remain below 58.2 Hz for greater than four seconds cumulatively per simulated event, and shall not remain below 58.5 Hz for greater than ten seconds cumulatively per simulated event, and shall not remain below 59.3 Hz for greater than 30 seconds, cumulatively per simulated event.

~~R6.3.~~6.3. Frequency overshoot resulting from operation of UFLS relays shall not exceed 61.8 Hz for any duration and shall not exceed 60.7 Hz for greater than 30 seconds, cumulatively per simulated event.

~~R6.4.~~6.4. Control voltage during and following UFLS operations such that the per unit Volts per Hz (V/Hz) does not exceed 1.18 for longer than two seconds cumulatively per simulated event, and does not exceed 1.10 for longer than 45 seconds cumulatively per simulated event at each generator bus and generator step-up transformer high-side bus associated with any:

~~R6.4.1.~~6.4.1. Individual generating unit greater than 20 MVA (gross nameplate rating) and connected at 60 kV and above. ~~directly connected to the BES.~~

~~R6.4.2.~~6.4.2. Generating plant/facility greater than 75 MVA (gross aggregate nameplate rating) and directly connected connected at 60 kV and above.~~to the BES.~~

R7. Each group of Planning Coordinators shall conduct a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement R6. The simulation shall include;

~~R7.1.~~7.1. Modeling the underfrequency trip settings of any generators that trip ~~at or~~ above the UFLS curve TBD [pjt1]~~58.0 Hz~~.

~~R7.2.~~7.2. Modeling the overfrequency trip settings of any generators that trip at or below the UFLS curve TBD ~~61.8 Hz.~~

~~R7.3.~~**7.3.** Modeling any automatic load restoration that ~~is designed to assist in~~impacts ~~stabilizing~~ frequency stabilization and operates within the duration of the simulations run for the assessment~~the simulated event~~.

R8. Each group of Planning Coordinators shall specify the content and create a database and annually maintain a ~~UFLS~~ database containing ~~relay~~ information ~~provided by their Transmission Owners and Distribution Providers~~ for use in ~~UFLS assessments and~~ event analyses and assessments of the UFLS program.

R9. Each Transmission Owner~~,~~ ~~Generator Owner~~ and Distribution Provider shall provide data to its group of Planning Coordinators according to the schedule and format specified by the group of Planning Coordinators to support maintenance of the database.

R10. Each Transmission Owner and Distribution Provider shall provide ~~load~~ tripping of forecast load in accordance with the UFLS program designed by the group of Planning Coordinators for each region in which it operates.

Consideration of Comments on the Second Draft of the Underfrequency Load Shedding Program Requirements — Project 2007-01

The Underfrequency Load Shedding Standard Drafting Team thanks all commenters who submitted comments on the UFLS Program Requirements. This document was posted for a 30-day public comment period from April 20, 2009 through May 21, 2009. The stakeholders were asked to provide feedback on the document through a special Electronic Standard Comment Form. There were 45 sets of comments, including comments from more than 120 different people from over 80 companies representing all of the 10 Industry Segments as shown in the table on the following pages.

http://www.nerc.com/filez/standards/Underfrequency_Load_Shedding.html

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, Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

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

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Brian Bartos	TRE UFLS Standard Drafting Team	X	X			X		X			

	Additional Member	Additional Organization	Region	Segment Selection
1.	Randy Jones	Calpine	ERCOT	5
2.	Raborn Reader	EPCO	ERCOT	NA
3.	Eddy Reece	Rayburn Country Electric Coop.	ERCOT	NA
4.	Barry Kremling	Guadalupe Valley Electric Coop.	ERCOT	NA
5.	Sergio Garza	Lower Colorado River Authority	ERCOT	5
6.	Steve Myers	ERCOT ISO	ERCOT	2
7.	Ken McIntyre	ERCOT ISO	ERCOT	2
8.	Dennis Kunkel	AEP	ERCOT	1
9.	Matt Pawlowski	NextEra	ERCOT	5

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2.	Group	Richard Kafka	Pepco Holdings, Inc - Affiliates	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	David O'Connor	Potomac Electric Power Co	RFC	1
2.	Dave Thorne	Potomac Electric Power Co	RFC	1
3.	Vic Davis	Delmarva Power & Light	RFC	1

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
4.	John Keller	Atlantic City Electric	RFC	1
5.	Walt Blackwell	Potomac Electric Power Co	RFC	1
6.	Alvin Depew	Potomac Electric Power Co	RFC	1

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3.	Group	Denise Koehn	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Kelly Johnson	Transmission Customer Service Engineering	WECC	1
2.	Greg Vasallo	Transmission Customer Service Engineering	WECC	1
3.	Larry Furumasu	Transmission Planning	WECC	1

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ralph Rufrano	New York Power Authority	NPCC	5
2.	Alan Adamson	New York State Reliability Council	NPCC	10
3.	Greg Campoli	New York Independent System Operator	NPCC	2
4.	Roger Champagne	Hydro-Quebec TransEnergie	NPCC	2
5.	Kurtis Chong	Independent Electricity System Operator	NPCC	2
6.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
7.	Manuel Couto	National Grid	NPCC	1
8.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
9.	Brian Evans-Mongeon	Utility Services	NPCC	8
10.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
11.	Michael Gildea	Constellation Energy	NPCC	6
12.	Brian Gooder	Ontario Power Generation Incorporated	NPCC	5
13.	Kathleen Goodman	ISO - New England	NPCC	2
14.	David Kiguel	Hydro One Networks Inc.	NPCC	1
15.	Michael Lombardi	Northeast Utilities	NPCC	1
16.	Randy MacDonald	New Brunswick System Operator	NPCC	2
17.	Bruce Metruck	New York PowerAuthority	NPCC	6

		Commenter	Organization	Industry Segment 1	2	3	4	5	6	7	8	9	10

18.	Robert Pellegrini	The United Illuminating Company	NPCC	1
19.	Michael Schiavone	National Grid	NPCC	1
20.	Michael Sonnelitter	FPL Energy/NextEra Energy	NPCC	5
21.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
22.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
23.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
5.	Group	Jim Busbin	Southern Company	X		X		X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	J. T. Wood	Southern Company Services, Inc.	SERC	1
2.	Hugh Francis	Southern Company Services, Inc.	SERC	1
3.	Bill Shultz	Southern Company Services, Inc.	SERC	5
4.	Phil Winston	Georgia Power Company	SERC	3
5.	Jonathan Glidewell	Southern Company Services, Inc.	SERC	1
6.	Marc Butts	Southern Company Services, Inc.	SERC	1

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6.	Group	Ken McIntyre	ERCOT ISO		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Steve Myers	ERCOT ISO	ERCOT	2
2.	John Schmall	ERCOT ISO	ERCOT	

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7.	Group	Jalal Babik	Electric Market Policy	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Louis Slade		SERC	6
2.	Mike Garton		NPCC	5

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8.	Group	Jason L. Marshall	Midwest ISO Stakeholders Standards Collaborators		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Lee Kittleson	Otter Tail Power	MRO	1

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
2.	Michael Ayotte	ITC Holdings	RFC	1									
9.	Group	Bob Jones	SERC UFLS Standards Drafting Team	X									
	Additional Member	**Additional Organization**	**Region**	**Segment Selection**									
1.	Rick Foster	Ameren Services Co.	SERC	1									
2.	John O'Connor	Progress Energy Carolinas	SERC	1									
3.	Pat Huntley	SERC Reliability Corp.	SERC	10									
4.	Jonathan Glidewell	Southern Co. Services	SERC	1									
5.	Tom Cain	TVA	SERC	1									
10.	Group	Peter A. Heidrich	FRCC Standards & Operations Departments										X
	Additional Member	**Additional Organization**	**Region**	**Segment Selection**									
1.	Linda Campbell	Florida Reliability Coordinating Council	FRCC	10									
2.	Eric Senkowicz	Florida Reliability Coordinating Council	FRCC	10									
11.	Group	Frank Gaffney	Florida Municipal Power Agency and Select Members	X		X	X	X				X	
	Additional Member	**Additional Organization**	**Region**	**Segment Selection**									
1.	Rich Kinas	Orlando Utilities Commission	FRCC	1, 3, 5									
2.	Jim Howard	Lakeland Electric	FRCC	1, 3, 5									
3.	Greg Woessner	Kissimmee Utilities Authority	FRCC	1, 3, 5									
4.	Cairo Venegas	Fort Pierce Utilities	FRCC	1, 3, 5									
12.	Group	Michael Brytowski	MRO NERC Standards Review Subcommittee										X
	Additional Member	**Additional Organization**	**Region**	**Segment Selection**									
1.	Carol Gerou	MRO	MRO	10									
2.	Neal Balu	WPS	MRO	3, 4, 5, 6									
3.	Joe DePoorter	MGE	MRO	3, 4, 5, 6									
4.	Ken Goldsmith	ALTW	MRO	4									
5.	Jim Haigh	WAPA	MRO	1, 6									

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10

6. Terry Harbour	MEC	MRO	1, 3, 5, 6
7. Joseph Knight	GRE	MRO	1, 3, 5, 6
8. Scott Nickels	RPU	MRO	3, 4, 5, 6
9. Dave Rudolph	BEPC	MRO	3, 4, 5, 6
10. Eric Ruskamp	LES	MRO	1, 3, 5, 6
11. Terry Bilke	MISO	MRO	2

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
13.	Group	Michael Gammon	Kansas City Power & Light	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Tim Hinken	Kansas City Power & Light	SPP	1, 3, 5, 6
2. Nick McCarty	Kansas City Power & Light	SPP	1, 3, 5, 6
3. Jerry Hatfield	Kansas City Power & Light	SPP	1, 3, 5, 6

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
14.	Group	Ben Li	IRC Standards Review Committee		X								

Additional Member	Additional Organization	Region	Segment Selection
1. James Castle	NYISO		2
2. Anita Lee	AESO		2
3. Charles Yeung	SPP		2
4. Bill Phillips	MISO		2
5. Matt Goldberg	ISO-NE		2
6. Steve Myers	ERCOT		2
7. Patrick Brown	PJM		2

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
15.	Individual	Russell A. Noble	Cowlitz County PUD			X							
16.	Individual	Edward C. Stein	Edward C. Stein - Self								X		
17.	Individual	Harvie Beavers	Colmac Clarion					X					
18.	Individual	Elvin Epting	City of Bedford			X							

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
19.	Individual	Ray Phillips	Alabama Municipal Electric Authority				X						
20.	Individual	Karl Bryan	US Army Corps of Engineers					X					
21.	Individual	Tom Nappi	NIPSCO	X		X		X					
22.	Individual	Kenneth D. Brown b/h Joseph Lalier, Design Engineer Electric Delivery Planning	Public Service Electric and Gas Company	X		X							
23.	Individual	Steve Alexanderson	Central Lincoln			X							
24.	Individual	Shawn Jacobs	SPP System Protection and Control Working Group	X	X	X							X
25.	Individual	Jonathan Appelbaum	Long island power Authority	X									
26.	Individual	Eric Mortenson	Exelon	X		X		X					
27.	Individual	Rao Somayajula	ReliabilityFirst Corporation										X
28.	Individual	Ronnie Frizzell	Arkansas Electric Cooperative Corporation				X						
29.	Individual	Greg Davis	System Protection & Control	X		X							
30.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
31.	Individual	Anthony Jablonski	Reliability First										X
32.	Individual	Bob Thomas, Kevin Wagner, Troy Fodor, Scott Robison	Illinois Municipal Electric Agency				X						

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
33.	Individual	Roger Champagne	Hydro-Québec TransEnergie (HQT)	X									
34.	Individual	Jim Sorrels	AEP	X		X		X	X				
35.	Individual	Vladimir Stanisic	Ontario Power Generation					X	X				
36.	Individual	Joe Springhetti	We Energies			X	X	X					
37.	Individual	Sandra Shaffer	PacifiCorp	X		X		X	X				
38.	Individual	Mike Sonnelitter	NextEra Energy Resources, LLC					X					
39.	Individual	Jason Shaver	American Transmission Company	X									
40.	Individual	Rick Terrill	Luminant Power					X					
41.	Individual	Kirit Shah	Ameren	X		X		X	X				
42.	Individual	Doug Hohlbaugh	FirstEnergy Corp	X		X	X	X	X				
43.	Individual	Armin Klusman	CenterPoint Energy	X									
44.	Individual	Dan Rochester	Independent Electricity System Operator		X								
45.	Individual	Alice Murdock	Xcel Energy	X		X		X	X				

1. **The UFLS programs typically have been developed within each Region by representatives from the vertically integrated utilities, Control Areas, power pools, etc. in that Region. The SDT initially proposed that all UFLS requirements be contained within regional UFLS standards to utilize specific expertise within the regions and recognize that UFLS programs can be successfully coordinated if they are designed to achieve the same system performance characteristics, even across interconnected regions. However, based on the rationale contained in the background, the SDT has developed a continent wide standard consistent with the historical practice that promotes the utilization of previous experience and expertise. As proposed, the continent-wide standard requires that all Planning Coordinators within a Region work together as a group to develop the UFLS program for that Region that conforms to the performance characteristics.**

   a. Do you agree that creating a continent wide standard preserves the intent of utilizing specific expertise within the regions to develop UFLS programs that meet common performance characteristics?

Summary Consideration:

- Most commenters agreed that creating a continent wide standard preserves the intent of utilizing specific expertise within the regions to develop UFLS programs that meet common performance characteristics.
- Commenters did suggest that regions may want to develop more detailed or stringent requirements. The SDT agrees and is ready to consider ~~and accept~~ any regional requests for variances. The SDT encourages the requestor of a variance to submit its request with ~~However, the submitter may wish to seriously consider preparing~~ a SAR which addresses the variance in detail.
- The SDT does not believe that the word “region” needs to be defined because the concept of a “region” is generally understood throughout the industry.

Organization	Yes or No	Question 1a Comments:
TRE UFLS Standard Drafting Team	Yes	The Texas Regional Entity Underfrequency Load Shedding Standard Drafting Team (TRE UFLS SDT) is pleased to provide these comments. These comments reflect the consensus of this specific regional standard drafting team and do not reflect the position of the Texas Regional Entity or ERCOT. The TRE UFLS SDT agrees that the basic common characteristics associated with the proposed UFLS standard provides for an appropriate level of required coordination within and, where applicable, between regions.

Organization	Yes or No	Question 1a Comments:
Response: Thank you for your comment.		
Pepco Holdings, Inc - Affiliates	Yes	The PHI Affiliates agree that the Planning Coordinators have their own expertise and access to the expertise of the TOs and DPs in their area.
Response: Thank you for your support to the continent-wide approach.		
Bonneville Power Administration	Yes	The continent-wide standard is a MINIMUM. Regions may still apply a higher standard.
Response: The SDT agrees and is ready to consider ~~and accept~~ any regional requests for variances. The SDT encourages the requestor of a variance to submit its request with ~~However, the submitter may wish to seriously consider preparing~~ a SAR which addresses the variance in detail.		
Northeast Power Coordinating Council	Yes	
Southern Company	Yes	Southern Company agrees with the comments submitted by the SERC Region for all questions in this comment form. Submitted SERC responses are essentially replicated in the responses we submit for Southern Company for questions 1-8.***We agree that creating a continent wide standard will preserve the intent of utilizing specific expertise within the region to develop UFLS schemes. First of all, this approach will provide uniformity among the regions for developing UFLS schemes, as all the regions will follow consistent performance characteristics specified in the standard. At the same time, the regions will have the flexibility to develop their own requirements to meet their specific needs.
Response: Thank you for your support to the continent-wide approach. The SDT agrees and is ready to consider ~~and accept~~ any regional requests for variances. The SDT encourages the requestor of a variance to submit its request with ~~However, the submitter may wish to seriously consider preparing~~ a SAR which addresses the variance in detail.		
ERCOT ISO	Yes	
Electric Market Policy	Yes	
Midwest ISO Stakeholders Standards	Yes	

Organization	Yes or No	Question 1a Comments:
Collaborators		
SERC UFLS Standards Drafting Team	Yes	We agree that creating a continent wide standard will preserve the intent of utilizing specific expertise within the region to develop UFLS schemes. First of all, this approach will provide uniformity among the regions for developing UFLS schemes, as all the regions will follow a consistent performance characteristics specified in the standard. At the same time, the regions will have the flexibility to develop their own requirements to meet their specific needs.
Response: Thank you for your support to the continent-wide approach. The SDT agrees and is ready to consider ~~and accept~~ any regional requests for variances. The SDT encourages the requestor of a variance to submit its request with ~~However, the submitter may wish to seriously consider preparing~~ a SAR which addresses the variance in detail.		
FRCC Standards & Operations Departments	Yes	We agree with the concept of the development of a Regional UFLS program that conforms to the common performance characteristics contained in the draft standard; however it is not clear what constitutes a 'region'. The SDT has repeatedly used the capitalized version ('Region') of the word in all of the associated documents (i.e. background, comment form) and reverted back to lower case version (region) in the standard. We believe that 'region' should be defined in the standard and incorporated into the NERC Glossary of Terms. This will ensure that the appropriate scope is applied in the development of Regional UFLS programs.
Response: The SDT intended "region" to relate to the traditional sense of a~~n~~ RRO with defined boundaries which is in the NERC Glossary, although somewhat out of date. The SDT did inadvertently capitalize the word "region" in the associated documents but did use it appropriately in the standard. The SDT feels that the concept of a "region" is generally understood throughout the industry and does not believe that a unique definition is required.		
Florida Municipal Power Agency and Select Members	Yes	
MRO NERC Standards Review Subcommittee	Yes	
Kansas City Power & Light	Yes	
IRC Standards Review Comittee	No	By definition, a continent wide standard intends to direct all regions into a consistent requirement and requires regions with varying practices to agree to a single standard. We support the approach taken in PRC-006-01 that specifies only the upper and lower bounds of UFLS protection requirements. We believe this is a reasonable approach to establish continent-wide requirements and allow regional expertise to design their regional UFLS programs.We agree with the proposal to

Organization	Yes or No	Question 1a Comments:
		preserve the intent of utilizing specific expertise within the regions to develop UFLS programs, but do not agree with the applicability and the way the standard is written to hold the Group of Planning Coordinators responsible for the requirements. Please see our comments under Q1b
Response: Thank you for your support to the continent-wide approach. See the response provided for the comment under Q1b.		
Cowlitz County PUD	Yes	
Edward C. Stein	Yes	
Colmac Clarion	Yes	
City of Bedford	Yes	
Alabama Municipal Electric Authority	Yes	
US Army Corps of Engineers	Yes	The continent wide standard establishes the performance characteristics that must be met and requiring the PCs within a Region to develop the specifics allows the implementation of the Rel Stndrd to also include local variances and has the added benefit of maintaining planning expertise.
Response: Thank you for your support to the continent-wide approach.		
NIPSCO	No	It really depends on how this is accomplished.
Response: The SDT encourages the commenter to provide more specifics for the next posting for consideration.		
Public Service Electric and Gas Company	Yes	The creation of a continent wide standard is acceptable as long as the responsibility for developing a UFLS program remains with the Planning Coordinators/Authorities in the Regions.
Response: Thank you for your support to the continent-wide approach.		
Central Lincoln	Yes	
SPP System Protection	Yes	

Organization	Yes or No	Question 1a Comments:
and Control Working Group		
Long island power Authority	Yes	
Exelon	Yes	
ReliabilityFirst Corporation	Yes	
Arkansas Electric Cooperative Corporation	Yes	
System Protection & Control	Yes	A continent wide standard will create desired system performance criteria, while allowing flexibility within the regions.
Response: Thank you for your support to the continent-wide approach.		
Duke Energy	No	R2 requires consistent application across the region. As long as R6 is met, there should be no requirement for all systems within the region to be consistent. This will create unnecessary work to redesign systems that could meet R6 just because they are not consistent with other systems in the region. Recommend deleting the words consistent application across from R2. This is similar to not requiring the regions to be consistent as long as R6 is met.
Response: The SDT developed the performance characteristics so that a "program" could be tailored to the needs of each region; however; at the same time not interfering with adjacent regions. The SDT did not intend that a "program" could have only one set of requirements, such as one set of drop frequencies or one specific percent load drop, for an entire region but that a "program" could be made up of different sections or sub regional systems identified as islands with different or the same requirements where consistent application of the applicable program requirements are applied in each island. The SDT has revised Requirement R2 to clarify this intent.		
ReliabilityFirst	Yes	
Illinois Municipal Electric Agency	Yes	

Organization	Yes or No	Question 1a Comments:
Hydro-Québec TransEnergie (HQT)	Yes	
AEP	Yes	As each Reliability Coordinator has it's own UFLS requirements, the UFLS programs between the Reliability Coordinator's need to work together.
Response: Thank you for your comment. Reliability Coordinators are not included in this standard because this standard addresses only multi-cycle automatic relay tripping (automatic load shedding not manual load shedding). The draft standard does include requirements to ensure coordination within a region by assigning responsibility to every Planning Coordinator within the region to work as a group. ~~There are additional requirements for islands that may be defined across regions within an interconnection. To the extent that an area covered by any individual Planning Coordinator may differ from corresponding Reliability Coordinator Areas, coordination may be required to ensure that all programs will function in a coordinated manner and that Reliability Coordinator response to any operation of the UFLS will be appropriate.~~		
Ontario Power Generation	Yes	
We Energies	No	We agree that a continent wide standard should be developed. However, we disagree with the approach taken with this draft of the standard. See our question 8 comments for more detail.
Response: Thank you for the support of a continent-wide standard. See the response to your comments on Question 8.		
PacifiCorp	Yes	PacifiCorp believes that the standard language is general enough to allow for regional differences. It is appropriate that the standard addresses what the parameters are, not how the parameters are to be implemented.
Response: Thank you for your support to the continent-wide approach. ~~The~~[sm1] ~~SDT agrees and is ready to consider and accept any regional requests for variances. The SDT encourages the requestor of a variance to submit its request with However, the submitter may wish to seriously consider preparing a SAR which addresses the variance in detail.~~		
NextEra Energy Resources, LLC	Yes	
American Transmission Company	Yes	
Luminant Power	Yes	

Organization	Yes or No	Question 1a Comments:
Ameren	No	It seems that regional standards with continent-wide performance characteristics would be the best mechanism to achieve this purpose. The only reason to have a continent wide standard to is to subscribe to the NERC process. There seems to be more focus on the process than the ultimate goal.
Response: The SDT has focused on both the ultimate goal and the process to achieve the goal. We believe the ultimate goal is to have regionally developed UFLS programs that are coordinated across and between regions. ~~While we believe this goal could be achieved with regional standards~~~~Since FERC approved Reliability Standards will be enforced under Law, appropriate procedures and processes must be~~ are not ~~in place to~~ require ~~accommodate such implementation by the regions.~~ As drafted, the proposed standard does not ~~bar~~ preclude the development of regional standards. The standard directs responsibility to the Planning Coordinators but allows them to develop/establish the UFLS program requirements in any manner they deem appropriate as long as they conform to the performance characteristics. ~~This allows them to get the task performed by another means other than their own work.~~		
FirstEnergy Corp	Yes	
CenterPoint Energy		
Independent Electricity System Operator	No	Further, we propose the scope of the standard be revised to clearly indicate that it focuses on the global events, as follows:To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency and assist recovery of frequency following widespread underfrequency events.
Response: The SDT does not agree with the inclusion of word “widespread” because of the numerous difficulties in ~~developing a definition~~defining “widespread” and the lack of completeness of the intent. The draft standard requires consideration of appropriate potential islands. Such islands may be widespread in some people’s minds and not so in others. Widespread, if viewed from a square mile perspective, could include large rural areas with little “critical” load. “Critical” urban load in relatively small concentrated geographic footprints may not necessarily fit within a widespread definition. The drafted purpose allows all these conditions to be included as appropriate with the programs to cover the relevant impacts to the bulk power system.		
Xcel Energy	Yes	

b. Do you agree that the SDT has assigned responsibility to the appropriate entity?

Summary Consideration:

1. Some commenters expressed concern over how the "group" concept for Planning Coordinators would be implemented. ~~IN~~ In response the SDT stated that a precedent for the "group" ~~precedent~~ approach ~~had~~ already has been developed and used in the current FERC approved BAL-002-0 which states requirements and compliance elements that direct responsibility to a Reserve Sharing Group composed of Balancing Authorities. In addition the "group" concept was first proven under the predecessor Phase 1 through 3 field testing standards procedure in the early 2000s. The purpose is to exert peer pressure on all individual responsible entities by judging the results of the group effort. This is apparent in the development of simulation model base cases for the Eastern Interconnection. In the event the overall program fails to meet the performance characteristics, each member of the group is deemed non-compliant.
2. ISSUE FOR SDT TO RESPONSE TO COMMENT - NERC/FERC STAFF needs to confirm the SDT direction on why some approved standards still refer to RROs and how SDT should address these circumstances.
3. The SDT has removed the ~~reference~~ qualifier to the ~~"~~Transmission Owners "with end-use Load connected to their Facilities where such end use load is not part of a Distribution Provider's load" in the Applicability to be in line with commenters, the Compliance Registry Guidelines, the Functional Model and the NERC Glossary. The standard ~~is still applicable to~~ does not preclude arrangements between Distribution Providers and Transmission Owners to ~~cover the situation where~~ provide load shedding ~~is provided~~ at transmission voltage levels.
4. This standard has not included requirements for generators since such requirements have been grouped with other generator requirements in PRC-024 ~~now~~ which was posted in February 2009 and presently is under development~~, being coordinated with this standard and previously posted~~. The SDT has coordinated development of this standard with the Generator Verification Standard Drafting Team (GV SDT) and will continue to do so to ensure coordination between the UFLS program requirements and the generator requirements.

Organization	Yes or No	Question 1b Comments:
TRE UFLS Standard Drafting Team	Yes	The TRE UFLS SDT believes specifically that data collection and assessments are most effectively carried out at the regional level. However, it is important to note one issue that will have to be dealt with in the regional standard and/or programs is how

Organization	Yes or No	Question 1b Comments:
		to account for the small load-serving systems (e.g., less than 25 MW) that are not NERC-registered.
Response: The SDT agrees with the commenter and offers the following observations. Notes 1 and 4 of the NERC Compliance Registry state in part that "The above are general criteria only. The Regional Entity considering registration of an organization not meeting (e.g., smaller in size than) the criteria may propose registration of that organization if the Regional Entity believes and can reasonably demonstrate~~5~~ that the organization is a bulk power system owner, or operates, or uses bulk power system assets, and is material to the reliability of the bulk power system." And that "If an entity is part of a class of entities excluded based on the criteria above as individually being unlikely to have a material impact on the reliability of the bulk power system, but that in aggregate have been demonstrated to have such an impact it may be registered for applicable standards and requirements irrespective of other considerations." The SDT has already received initial feedback from both NERC and FERC staffs that such a condition may exist for implementation of this standard since the effectiveness of an overall UFLS program must consider the entire load. The development of any UFLS program must include some means of providing a mutual/coordinated load shed for "smaller" entities such as agreements by "larger" entities to provide such load shedding.		
Pepco Holdings, Inc - Affiliates	Yes	
Bonneville Power Administration	Yes	BPA will have to have delegation agreements with DP's when BPA is covering their loads with BPA-UFLS relays or through other UFLS armed load in our BAA.
Response: The SDT agrees that the approach the commenter is suggesting is one appropriate way to address the needs, and thanks the commenter for their support.		
Northeast Power Coordinating Council	No	We agree that the Planning Coordinator is the correct Functional Model entity based on having a wide-area view and the planning expertise to perform UFLS assessments. However, it is not clear to us whether applicability can be assigned to a group of Planning Coordinators as opposed to individual Planning Coordinators.
Response: A precedent for ~~T~~the "group" ~~precedent~~ approach ~~had~~ already has been developed and used in the current FERC approved BAL-002-0 which states requirements and compliance elements that direct responsibility to a Reserve Sharing Group composed of Balancing Authorities. In addition the "group" concept was first proven under the predecessor Phase 1 through 3 field testing standards procedure in the early 2000s. The purpose is to exert peer pressure on all individual responsible entities by judging the results of the group effort. This is apparent in the development of simulation model base cases for the Eastern Interconnection. In the event the overall program fails to meet the performance characteristics, each member of the group is deemed non-compliant.		
Southern Company	No	No, because the Planning Coordinator (PC) role is implemented differently across the regions. The Transmission Planner (TP) is the most appropriate entity to design the UFLS scheme since the TP has the detailed system knowledge and is generally better positioned to develop the scheme. Also, the Transmission Owner (TO) is the most appropriate entity to be responsible for implementation of the UFLS scheme. The TO generally has a wider area of responsibility, thus ensuring all

Organization	Yes or No	Question 1b Comments:
		load would be included in the implementation. This approach would allow the Distribution Providers (DP) to participate if they choose to implement the UFLS scheme providing the most selective load tripping, while at the same time allowing for more efficient aggregation of smaller DPs' load into the overall scheme.
Response: The SDT believes the Planning Coordinator is the appropriate applicable entity since design of an UFLS program requires a wide-area view. Since the Planning Coordinator must work closely with the Transmission Planners in performance of its role~~, the SDT believes the Planning Coordinator is the appropriate applicable entity since~~ the SDT anticipates that the Transmission Planners' expertise will be utilized. ~~the Planning Coordinator (PC) by its very nature needs to have at a minimum as wide an area view as the Transmission Planner (TP) if not larger.~~ The Planning Coordinator is the Functional Model entity best equipped to model~~s take in account~~ adjacent ~~PC~~ areas which are needed to ~~perform~~ identify islands as well as simulate regional or inter-regional ~~simulations of~~ underfrequency events – detailed and localized views cannot do that. ~~In addition, the UFLS database that states pertinent modeling information is available to the PC as well as the TP.~~ **As for implementation, ~~the Transmission Owner (TO), from a practical standpoint, automatic UFLS tripping at 100KV or above is just not the normal – much UFLS tripping is initiated at less than 100kV. S~~since the Distribution Provider (DP) is the entity that connects end-user load to the electrical system, making the Distribution Provider the applicable~~ility~~ entity will ensure all load is covered. This is confirmed by the Functional Model and the interim changes made to the NERC Compliance Registry Guidelines. While the standard assigns responsibility to the Distribution Provider it is not prescriptive in defining how the load shedding is to be implemented. The standard ~~already allows~~ does not preclude aggregation by the Distribution Providers ~~and~~ or arrangements with Transmission Owners for tripping at different voltage levels on different systems~~, but still holds the DP as the responsible entity~~.**		
ERCOT ISO	Yes	ERCOT ISO believes the Planning Coordinator is the correct responsible entity.
Response: Thank you for your support.		
Electric Market Policy	Yes	
Midwest ISO Stakeholders Standards Collaborators	No	We can understand the assignment of certain responsibilities to a Planning Coordinator. However, attempting to force Planning Coordinators to develop groups and then holding the entire group accountable for one another's compliance is unworkable.
Response: A precedent for ~~T~~the "group" ~~precedent~~ approach ~~had~~ already has been developed and used in the current FERC approved BAL-002-0 which states requirements and compliance elements that direct responsibility to a Reserve Sharing Group composed of Balancing Authorities. In addition the "group" concept was first proven under the predecessor Phase 1 through 3 field testing standards procedure in the early 2000s. The purpose is to exert peer pressure on all individual responsible entities by judging the results of the group effort. This is apparent in the development of simulation model base cases for the Eastern Interconnection. In the event the overall program fails to meet the performance characteristics, each member of the group is deemed non-compliant.		

Organization	Yes or No	Question 1b Comments:
SERC UFLS Standards Drafting Team	No	No, because Planning Coordinator(PC) role is implemented differently across the regions. The Transmission Planner(TP) is the most appropriate entity to design the UFLS scheme since the TP has the detailed system knowledge and is generally better positioned to develop the scheme. Also, the Transmission Owner (TO) is the most appropriate entity to be responsible for implementation of the UFLS scheme. The TO generally has a wider area of responsibility, thus ensuring all load would be included in the implementation. This approach would allow the Distribution Providers (DP) to participate if they choose to implement the UFLS scheme providing the most selective load tripping, while at the same time allowing for more efficient aggregation of smaller DPs' load into the overall scheme.
Response: The SDT believes the Planning Coordinator is the appropriate applicable entity since design of an UFLS program requires a wide-area view. Since the Planning Coordinator must work closely with the Transmission Planners in performance of its role, the SDT believes ~~the Planning Coordinator is the appropriate applicable entity since~~ that the Transmission Planners' expertise will be utilized. ~~the Planning Coordinator (PC) by its very nature needs to have at a minimum as wide an area view as the Transmission Planner (TP) if not larger.~~ The Planning Coordinator is the Functional Model entity best equipped to model~~s take in account~~ adjacent ~~PC~~ areas which are needed to ~~perform~~ identify islands as well as simulate regional or inter-regional ~~simulations of~~ underfrequency events – detailed and localized views cannot do that. ~~In addition, the UFLS database that states pertinent modeling information is available to the PC as well as the TP.~~ **As for implementation, ~~the Transmission Owner (TO), from a practical standpoint, automatic UFLS tripping at 100KV or above is just not the normal – much UFLS tripping is initiated at less than 100kV. S~~since the Distribution Provider (DP) is the entity that connects end-user load to the electrical system, making the Distribution Provider the applicable~~ility~~ entity will ensure all load is covered. This is confirmed by the Functional Model and the interim changes made to the NERC Compliance Registry Guidelines. While the standard assigns responsibility to the Distribution Provider it is not prescriptive in defining how the load shedding is to be implemented. The standard ~~already allows~~ does not preclude aggregation by the Distribution Providers ~~and~~ or arrangements with Transmission Owners for tripping at different voltage levels on different systems~~, but still holds the DP as the responsible entity~~.**		
FRCC Standards & Operations Departments	No	Although we agree with the concept of the coordinated effort to design an underfrequency load shedding program, we believe that there is a need to establish an entity with the overall responsibility of coordinating the efforts of the Planning Coordinators. We recommend that the Regional Entity be responsible for overseeing the development of the Regional UFLS program while requiring the Planning Coordinators to participate in the process. Although the provided background material dismisses the idea of expanding the applicability to include the Regional Entity, the precedent has been established by assigning applicability to the Regional Entity in the CIP standards.
Response THIS RESPOSE WILL NEED STATEMENTS BY NERC/FERC STAFFS TO CONFIRM THE SDT DIRECTION AS WELL AS A REASON WHY SOME APPROVED STANDARDS STILL REFER TO RROs.		
Florida Municipal Power Agency and Select Members	No	While we agree that the responsibility resides with a regional planning coordinator type of Entity, a group of Planning Coordinators is a somewhat nebulous term and calls into question the enforceability of the standard, and therefore calls into question whether FERC will approve it or not. If the group of Planning Coordinators is noncompliant, who is noncompliant? Who negotiates settlement? Who would pay a potential fine? If one of the Entities does not provide data for the database

Organization	Yes or No	Question 1b Comments:
		required in R8, are all of the PCs noncompliant? As with nearly all things, in order to get something done, leadership is necessary, so, although this is certainly a team effort, one Entity ought to be designated to offer that leadership. Why not keep it the Regional Entity? Alternatively, is there sufficient justification to create a new function called the Regional Planning Coordinator? Or to change the definitions of Planning Coordinator, Transmission Planner and Resource Planner to essentially cause Transmission Planners and Resource Planners to focus on more local issues whereas the Planning Coordinator by definition becomes regional (and hence eliminates the need for the term a group of Planning Coordinators?)

Response: A precedent for ~~T~~the "group" ~~precedent~~ approach ~~had~~ already has been developed and used in the current FERC approved BAL-002-0 which states requirements and compliance elements that direct responsibility to a Reserve Sharing Group composed of Balancing Authorities. In addition the "group" concept was first proven under the predecessor Phase 1 through 3 field testing standards procedure in the early 2000s. The purpose is to exert peer pressure on all individual responsible entities by judging the results of the group effort. This is apparent in the development of simulation model base cases for the Eastern Interconnection. In the event the overall program fails to meet the performance characteristics, each member of the group is deemed non-compliant.

As the commenter suggests, the group of Planning Coordinator may chose to have another entity or group, such as the Regional Entity or even a consultant, perform the required tasks for them with the understanding that the "group" is still ~~responsibility to~~responsible to get the tasks completed to meet compliance.

Organization	Yes or No	Question 1b Comments:
MRO NERC Standards Review Subcommittee	No	We agree with the assignment of selected responsibilities to the Planning Coordinator (PC) and suggest that the NERC Compliance Registry Criteria be revised to add the Planning Coordinator function and the Regional Entities be directed to register applicable entities to this function. Responsibility for several requirements are assigned to a "group" of Planning Coordinators. However, these groups do not presently exist and are not registered or legal entities. Perhaps a Planning Coordinator Group (PCG) should be added to the Applicability section and the NERC Compliance Registry Criteria be revised to add the PCG function, similar to the Reserve Sharing Group (RSG) function. Then, Regional Entities might be directed to register applicable entities to this function. Establishing PCGs would help PCs clarify how the group's responsibilities for compliance and liabilities would be assigned to each of its members.If a registered PCG function is not established, then drafting team should revise R1 to require all Planning Coordinators in a region to form a joint agreement to cover fulfillment of the subsequent UFLS requirements. See details in response to question 8. Transmission Owners function should be removed because it is unnecessary and redundant with the Distribution Provider function. Per NERC Compliance Registry Criteria Rev. 5.0 (Sections II.b and III.b.2), any Transmission Owner that provides and operates the ?wires? to end-use Load served at transmission voltages must register as a Distribution Provider or transfer the responsibility for applicable UFLS requirements to a registered Distribution Provider by written agreement. However, the TO function should be retained if SDT adopts the suggestion of adding R11 and R12 reguarding reactive power devices (in Q8).

Organization	Yes or No	Question 1b Comments:
		Generator Owners should be assigned responsibility for coordinating any generator off nominal frequency protection with any applicable UFLS relaying and for providing generator off nominal frequency protection information to the Planning Coordinator. So, the Generator Owner function should be added to the Applicability section. The SDT should coordinate with PRC-024 so that requirements do not overlap.

Response: A precedent for ~~T~~the "group" ~~precedent~~ approach ~~had~~ already has been developed and used in the current FERC approved BAL-002-0 which states requirements and compliance elements that direct responsibility to a Reserve Sharing Group composed of Balancing Authorities. In addition the "group" concept was first proven under the predecessor Phase 1 through 3 field testing standards procedure in the early 2000s. The purpose is to exert peer pressure on all individual responsible entities by judging the results of the group effort. This is apparent in the development of simulation model base cases for the Eastern Interconnection. In the event the overall program fails to meet the performance characteristics, each member of the group is deemed non-compliant.

The SDT has removed the qualifier~~reference~~ to the ~~"~~Transmission Owners "with end-use Load connected to their Facilities where such end use load is not part of a Distribution Provider's load" in the Applicability to be in line with commenters, the Compliance Registry Guidelines, the Functional Model and the NERC Glossary. The standard ~~is still applicable to~~ does not preclude arrangements between Distribution Providers and Transmission Owners to ~~cover the situation where~~ provide load shedding ~~is provided~~ at transmission voltage levels.

NEED RESPONSE FOR REACTIVE POWER DEVISES AFTER WE REVIEW Q8

This standard has not included requirements for generators since such requirements have been grouped with other generator requirements in PRC-024 ~~now~~ which was posted in February 2009 and presently is under development~~, being coordinated with this standard and previously posted~~. The SDT has coordinated development of this standard with the Generator Verification Standard Drafting Team (GV SDT) and will continue to do so to ensure coordination between the UFLS program requirements and the generator requirements.

Organization	Yes or No	Question 1b Comments:
Kansas City Power & Light	No	It is unnecessary to designate a Transmission Provider with end-use load. That is a Distribution Provider. Generator Owners should be added since generator data will be required to be provided for modeling purposes.

Response: The draft standard did not include the Transmission Provider; however, the Transmission Owner was included. The SDT has removed the ~~reference~~ qualifier to the ~~"~~Transmission Owners "with end-use Load connected to their Facilities where such end use load is not part of a Distribution Provider's load" in the Applicability to be in line with commenters, the Compliance Registry Guidelines, the Functional Model and the NERC Glossary. The standard ~~is still applicable to~~ does not preclude arrangements between Distribution Providers and Transmission Owners to ~~cover the situation where~~provide load shedding ~~is provided~~ at transmission voltage levels.

This standard has not included requirements for generators since such requirements have been grouped with other generator requirements in PRC-024 ~~now~~ which was posted in February 2009 and presently is under development~~, being coordinated with this standard and previously posted~~. The SDT has coordinated development of this standard with the Generator Verification Standard Drafting Team (GV SDT) and will continue to do so to ensure coordination between the UFLS program requirements and the generator requirements.

Organization	Yes or No	Question 1b Comments:
IRC Standards Review Comittee	No	We do not agree with the SDT to remove the Regional Entities from being assigned requirements on the basis that: ?? the Regional Entities are not user, owners, or operators of the Bulk Electric System and should not be assigned responsibility for requirements.? There are a number of existing standards, for examples: CIP standards, BAL-002, EOP-004, EOP-007, FAC-013, FAC-012, to name a few, that hold the Regional Entities (Regional Reliability Organizations, as written) responsible for standard requirements. Unless and until an assessment is conducted to conclude that all such requirements can be replaced with an alternative responsible entity(ies), we do not see a problem with the Regional Entities being held responsible for complying with standards.The way the requirements are assigned in this draft standard (each group of Planning Coordinators shall) leaves room for confusion to the industry and debates in the compliance audit process. Unless the Group of PCs is registered as an entity, we are unable to see how the pertinent requirements can be legally enforced. An alternative is to assign these requirements to the Regional Entities, OR, develop a requirement for each PC to have an agreement with its Regional Entity to engage in the design of a UFLS program and coordinate settings with other PCs? programs to achieve consistent application across the region. This way, the requirements can be written to hold Each Planning Coordinator rather than Each group of Planning Coordinators. If this approach is adopted, R1 and R2 could be combined as follows:R1. Each Planning Coordinator shall have an agreement with its Regional Entity to participate with other Planning Coordinators within the region in coordinating the design of an underfrequency load shedding program for consistent application across the region.With this change, R3 may be combined with R1 or be a separate requirement holding each PC responsible for engaging in the development of the criteria.And R3 to R8 can be revised to ?Each Planning Coordinator, in meeting the intent of R1, shall?The proposed changes provide clarity to the PC?s responsibility and removes gray areas in the compliance audit process.
Response: THIS RESPOSE WILL NEED STATEMENTS BY NERC/FERC STAFFS TO CONFIRM THE SDT DIRECTION AS WELL AS A REASON WHY SOME APPROVED STANDARDS STILL REFER TO RROs. [HSM Note: There are other alternatives, such as a Type 2 JRO between PCs with regard to the limited requirements to develop a Regional UFLS program, or, alternatively, the newly proposed Coordinated Functional Registration (CFR) that is proposed in the revisions to the NERC ROP Section 500 (specifically a new Section 508), other delegation agreements are allowed, and I am sure there are probably other ways, or "hows", to do this. The standard should address only the "what" needs to be done.]		
	Yes	I would defer to the opinion of the Planning Coordinators, but am wondering why the RC is not involved. As far as the TO and DP responsibility I see no problem as long as it is clear what data and load tripping is required.
Response: Reliability Coordinators are not included in this standard because this standard addresses only multi-cycle automatic relay tripping (automatic load shedding not manual load shedding). Since real time automatic UFLS installations must be planned, budgeted, and installed months and years in advance with estimated knowledge of how the system ~~confirmation~~ configuration and loading will change over time, the SDT focused on the Planning Coordinator. The Reliability Coordinator ~~in~~ is not in the business of planning load transfers, adding new circuits, or performing simulations of estimated and proposed system configurations. These are the tasks performed by traditional system planners. ~~To the extent that an area covered by any individual Planning Coordinator may differ from corresponding Reliability Coordinator Areas, coordination may be required to ensure that all programs will function in a coordinated manner and that Reliability Coordinator response to any operation of the UFLS will be appropriate.~~		

Organization	Yes or No	Question 1b Comments:
Edward C. Stein	Yes	
Colmac Clarion	Yes	
City of Bedford	Yes	
Alabama Municipal Electric Authority	Yes	
US Army Corps of Engineers	Yes	
NIPSCO	Yes	The planning groups yes
Response: Thank you for your support.		
Public Service Electric and Gas Company	Yes	
Central Lincoln	No	"Transmission Owners with end-use Load connected to their Facilities where suchend use load is not part of a Distribution Providers load"TOs that meet the registry criteria for DP should be registered as such. If they don't meet the criteria, they are not required to have UFLS and this standard is not applicable to the small unregistered distribution system in question. Instead, I propose that TOs be included with no qualification, or a qualification that expresses the following situation: A DP and a TO may jointly decide the most effective location for UFLS may be on the TO's system, where it may be easier to reach the load shedding target. It would then be the TO that would be required to meet R9 and R10.
Response: ~~The draft standard did not include the Transmission Provider; however, the Transmission Owner was included.~~ The SDT has removed the ~~reference~~ qualifier to the ~~“~~Transmission Owners “with end-use Load connected to their Facilities where such end use load is not part of a Distribution Provider’s load” in the Applicability to be in line with commenters, the Compliance Registry Guidelines, the Functional Model and the NERC Glossary. The standard ~~is still applicable to~~ does not preclude arrangements between Distribution Providers and Transmission Owners (TO) to ~~cover the situation where~~ provide load shedding ~~is provided~~ at transmission voltage levels. **~~From a practical standpoint, tripping at 100KV or above is just not the normal – much UFLS tripping is initiated at less than 100kV.~~ Since the Distribution Provider (DP) is the entity that connects end-user load to the electrical system, making the Distribution Provider the applicable~~ility~~ entity will ensure all**		

Organization	Yes or No	Question 1b Comments:
load is covered. This is confirmed by the Functional Model and the interim changes made to the NERC Compliance Registry Guidelines. While the standard assigns responsibility to the Distribution Provider it is not prescriptive in defining how the load shedding is to be implemented. The standard ~~already allows~~ does not preclude aggregation by the Distribution Providers or arrangements with Transmission Owners for tripping at different voltage levels on different systems~~but still holds them as the responsible entity~~.		
SPP System Protection and Control Working Group	Yes	
Long island power Authority	Yes	
Exelon	No	GOs should be included as applicable entities because they play an important role in matching load and generation in periods of frequency excursion. That being said, the standard should not require the installation of under frequency relays at generators that would remain on line beyond these minimum requirements.
Response: This standard has not included requirements for generators since such requirements have been grouped with other generator requirements in PRC-024 ~~now~~ which was posted in February 2009 and presently is under development~~, being coordinated with this standard and previously posted~~. The SDT has coordinated development of this standard with the Generator Verification Standard Drafting Team (GV SDT) and will continue to do so to ensure coordination between the UFLS program requirements and the generator requirements.		
ReliabilityFirst Corporation	Yes	
Arkansas Electric Cooperative Corporation	No	I agree with the Planning Coordinator Group concept but this group should be required to solicit the input from other functional entities such as the GO, TO, TOP, DP, and LSE when developing the criteria and plans. These other entities will have valuable insight as to what should and should not be included in the UFlS programs and need to have a voice during the development of these programs. I would suggest adding the following sentence to R2 and R3 "The design(R2)/criteria(R3)shall be developed taking into consideration the input and feedback from the Generator Owners, Transmission Owners, Transmission Operators, Distribution Providers and Load Serving Entities to which the design/critria shall apply." While the Distribution Provider may own the equipment the LSE will play a valuable role in determining which equipment should be used to shed load. The LSE and not necessarily the DP has a better knowledge of the load makeup served by the DP's equipment and thus may be in a better position to identify the best location for UF relays. For example the LSE would know if a circuit has a critical load where the DP may or may not have this knowledge. Since load is what is being dropped, the LSE is the best one to make the determation of which load is to be shed. The LSE may not need be an

Organization	Yes or No	Question 1b Comments:
		applicable entity but the UF programs and plans should not be developed without their input.It may be that the standard applicability needs to be expanded to these other entities by adding something to the effect of: GO, TO, TOP, DP, and LSE will participate in the development of the UFLS program and plans by providing input and feedback.
Response: The commenter is referencing the issues that must be addressed to determine "how" the program is to be implemented. The standard states measurable requirements for "what" is to be accomplished. Choice of circuits to be tripped based on voltage, location, configuration, etc. are all implementation issues not specified in the standard. Responsible entities are allowed to choose the most appropriate manner in which to implement the ~~design~~ program design to achieve the reliability objectiveion of arresting frequency decline.		
System Protection & Control	Yes	
Duke Energy	No	The proposed standard's requirements R1-R8 are applicable to Planning Coordinator, which isn't a registered function in NERC's compliance registry. Without applicability to a registered entity such as the Planning Authority or Transmission Planner, there is no clear responsibility for compliance. Also it is unclear how compliance can reasonably be enforced when responsibility is shared by a group of entities. It is not clear how non-compliance with R6 is addressed given that all PCs in the region are combined by R1. Somehow, each PC must be allowed to demonstrate compliance to the standard independently so compliant PCs are not penalized along with the non-compliant one(s).
Response: NERC has submitted and FERC has accepted a statement that the previously defined term of Planning Authority is the same entity/function as the currently approved Functional Model term Planning Coordinator. Based on the "Comments of the North American Electric Reliability Corporation on the Notice of Proposed Rulemaking for Facilities Design, Connections and Maintenance Reliability Standards", Docket No. RM07-3-000, dated September 19th, 2007, pages 15 and 16, NERC states: "While NERC recognizes there will be a need to modify the compliance registration process to include the planning coordinator, in the future, on an interim basis, any requirement assigned to the planning authority is assumed also to apply to the planning coordinator. Because no approved standards apply to the "planning coordinator at this time, the modification to the NERC Compliance Registry is not a current issue." This document can be found at: http://www.nerc.com/docs/docs/ferc/FinalFAC.pdf. Based on this document, the SDT feels the Planning Coordinator is the correct entity. **In addition, the current NERC Glossary of terms indicates that the Planning Authority and Planning Coordinators are the same.** **As for the issue concerning applicability, a precedent for the "group" ~~precedent~~ approach ~~had~~ already has been developed and used in the current FERC approved BAL-002-0 which states requirements and compliance elements that direct responsibility to a Reserve Sharing Group composed of Balancing Authorities. In addition the "group" concept was first proven under the predecessor Phase 1 through 3 field testing standards procedure in the early 2000s. The purpose is to exert peer pressure on all individual responsible entities by judging the results of the group effort. This is apparent in the development of simulation model base cases for the Eastern Interconnection. In the event the overall program fails to meet the performance characteristics, each member of the group is deemed non-compliant.**		

Organization	Yes or No	Question 1b Comments:
ReliabilityFirst	No	The Transmision Owner with end use load connected ... is out of line with the NERC Functional Model knowing that if a Transmision Owner has end use load connected, by definition, the Transmision Owner must register as a Distribution Provider. Therefore, using just the Distribution Provider in the UFLS standard is adequate and complete.
Response: The SDT has removed the ~~reference~~ qualifier to the ~~"~~Transmission Owners "with end-use Load connected to their Facilities where such end use load is not part of a Distribution Provider's load" in the Applicability to be in line with commenters, the Compliance Registry Guidelines, the Functional Model and the NERC Glossary. The standard ~~is still applicable to~~ does not preclude arrangements between Distribution Providers and Transmission Owners to ~~cover the situation where~~ provide load shedding ~~is provided~~ at transmission voltage levels.		
Illinois Municipal Electric Agency		
Hydro-Québec TransEnergie (HQT)	No	HQT agree that the Planning Coordinator is the correct Functional Model entity based on having a wide-area view and the planning expertise to perform UFLS assessments. However, it is not clear whether applicability can be assigned to a group of Planning Coordinators as opposed to individual Planning Coordinator.
Response: A precedent for ~~T~~the "group" ~~precedent~~ approach ~~had~~ already has been developed and used in the current FERC approved BAL-002-0 which states requirements and compliance elements that direct responsibility to a Reserve Sharing Group composed of Balancing Authorities. In addition the "group" concept was first proven under the predecessor Phase 1 through 3 field testing standards procedure in the early 2000s. The purpose is to exert peer pressure on all individual responsible entities by judging the results of the group effort. This is apparent in the development of simulation model base cases for the Eastern Interconnection. In the event the overall program fails to meet the performance characteristics, each member of the group is deemed non-compliant.		
AEP	No	Reliability Coordinators have set up specifics standards on the set points for UFLS. The proposed standard misses this circumstance by not including the Reliability Coordinator in the standard. How would this be reconciled?
Response: The SDT is unaware of any NERC Reliability Standards that require Reliability Coordinator to establish set points for automatic UFLS programs. The SDT has drafted the standard to accommodate existing regional practices where possible; however, the SDT believes the Planning Coordinator is the appropriate applicable entity since design of an UFLS program requires a wide-area view. Since the Planning Coordinator must work closely with the Reliability Coordinator in performance of its role, the SDT anticipates that the Reliability Coordinators' expertise will be utilized. ~~The Reliability Coordinator needs to understand how the various automatic UFLS programs that are required to be compliant with this standard function so that the development of manual UFLS procedures can be properly coordinated.~~		
Ontario Power Generation	Yes	

Organization	Yes or No	Question 1b Comments:
We Energies	No	See our question 8 comments for more detail.
Response: See response to Question 8 comments.		
PacifiCorp	Yes	While PacifiCorp agrees that coordination between Planning Coordinators is necessary in order to design and implement an effective UFLS program, it has some concern regarding the assignment of responsibility for compliance with this standard to a currently undefined group of Planning Coordinators. There is no such entity in the Functional Model and it is therefore unclear as to how this group will function and by whom it will be governed. The way the standard is currently drafted raises significant questions regarding how the requirements will be enforced, how a Planning Coordinator will know what group to participate in, how its participation in such group will be evaluated, how disagreements between group participants will be resolved, and which entity, among such group of Planning Coordinators, will be responsible for any potential violations. PacifiCorp recommends that either 1) the SDT assign the UFLS coordination responsibility and governance to the Regional Entity; or 2) the SDT re-draft the standard in such a way that allows Planning Coordinators to assign their compliance responsibility and activity to an agent Planning Coordinator Group similar to the group concept utilized in BAL-002-0 that allows Balancing Authorities to assign compliance responsibility to a Reserve Sharing Group.
Response: The standard states that the group will consist "of all the Planning Coordinators within the region for each of the regions in which it performs the Planning Coordinator function." As such the "group" is not a Functional Entity" ~~on to~~ unto itself and is therefore not defined in the Functional Model. A precedent for ~~T~~the "group" ~~precedent~~ approach ~~had~~ already has been developed and used in the current FERC approved BAL-002-0 which states requirements and compliance elements that direct responsibility to a Reserve Sharing Group composed of Balancing Authorities. In addition the "group" concept was first proven under the predecessor Phase 1 through 3 field testing standards procedure in the early 2000s. The purpose is to exert peer pressure on all individual responsible entities by judging the results of the group effort. This is apparent in the development of simulation model base cases for the Eastern Interconnection. In the event the overall program fails to meet the performance characteristics, each member of the group is deemed non-compliant. How the Planning Coordinators will interact is determined by the participants, allowing them to work in any ~~as an effective~~ manner ~~as~~ they choose. The group objective is to develop a "program" that will be evaluated when a UFLS assessment is conducted that demonstrates through dynamic simulation whether the UFLS program design meets the performance characteristics.		
NextEra Energy Resources, LLC		No comment.
American Transmission Company	No	We agree with the assignment of selected responsibilities to the Planning Coordinator (PC) and suggest that NERC revise the Compliance Registry Criteria to add the Planning Coordinator and direct the Regional Entities to register applicable entities to this function. Responsibility for several requirements are assigned to a "group" of Planning Coordinators, but Planning Coordinator Group (PCG) does not appear in the list of applicable entities. We agree with leaving the PCG entity off of the list. However, without a PCG entity in the list, the applicable requirements should be reworded to make each Planing Coordinator individually

Organization	Yes or No	Question 1b Comments:
		responsible for their contribution to the group actions. Suggested wording for each applicable requirement is provided in the response to Question 8.If the drafting team decides to apply requirement responsiblities to a PCG, then NERC should revise the Compliance Registry Criteria to add the PSG and direct the Regional Entities to register the applicable entities to this function. Since regional PSGs have not been formed as legal entities in the past, then going this direction would require PC to establish contracts to form these groups in order to clearly define the compliance and sanction liabilities of each PC in the group. Transmission Owners should be removed because it is redundant with Distribution Provider. Per NERC Compliance Registry Criteria Rev. 5.0 (Sections II.b and III.b.2), any Transmission Owner that provides and operates the wires to end-use Load served at transmission voltages must register as a Distribution Provider or transferred the responsibility for applicable UFLS requirements to a registered Distribution Provider by written agreement. Therefore, we suggest the removal of Transmission Owner from the Applicability section. Generator Owners (GO) should be included in the Applicable entities section and requirements should be added that assign GOs the responsibility for providing generator off nominal frequency protection information to the Planning Coordinator and for coordinating any generator off nominal frequency protection with any applicable UFLS program.

Response: NERC has submitted and FERC has accepted a statement that the previously defined term of Planning Authority is the same entity/function as the currently approved Functional Model term Planning Coordinator. Based on the "Comments of the North American Electric Reliability Corporation on the Notice of Proposed Rulemaking for Facilities Design, Connections and Maintenance Reliability Standards", Docket No. RM07-3-000, dated September 19th, 2007, pages 15 and 16, NERC states: "While NERC recognizes there will be a need to modify the compliance registration process to include the planning coordinator, in the future, on an interim basis, any requirement assigned to the planning authority is assumed also to apply to the planning coordinator. Because no approved standards apply to the "planning coordinator at this time, the modification to the NERC Compliance Registry is not a current issue." This document can be found at: http://www.nerc.com/docs/docs/ferc/FinalFAC.pdf. Based on this document, the SDT feels the Planning Coordinator is the correct entity. In addition, the current NERC Glossary of terms indicates that the Planning Authority and Planning Coordinators are the same.

A precedent for ~~T~~the "group" ~~precedent~~ approach ~~had~~ already has been developed and used in the current FERC approved BAL-002-0 which states requirements and compliance elements that direct responsibility to a Reserve Sharing Group composed of Balancing Authorities. In addition the "group" concept was first proven under the predecessor Phase 1 through 3 field testing standards procedure in the early 2000s. The purpose is to exert peer pressure on all individual responsible entities by judging the results of the group effort. This is apparent in the development of simulation model base cases for the Eastern Interconnection. In the event the overall program fails to meet the performance characteristics, each member of the group is deemed non-compliant.

The SDT has removed the qualifier~~reference~~ to the ~~"~~Transmission Owners "with end-use Load connected to their Facilities where such end use load is not part of a Distribution Provider's load" in the Applicability to be in line with commenters, the Compliance Registry Guidelines, the Functional Model and the NERC Glossary. The standard ~~is still applicable to~~ does not preclude arrangements between Distribution Providers and Transmission Owners to ~~cover the situation where~~ provide load shedding ~~is provided~~ at transmission voltage levels.

Organization	Yes or No	Question 1b Comments:
This standard has not included requirements for Generator Owners since such requirements have been grouped with other generator requirements in PRC-024 ~~now~~ which was posted in February 2009 and presently is under development~~, being coordinated with this standard and previously posted~~. The SDT has coordinated development of this standard with the Generator Verification Standard Drafting Team (GV SDT) and will continue to do so to ensure coordination between the UFLS program requirements and the generator requirements.		
Luminant Power	Yes	
Ameren	No	It seems that the Transmission Planner would be a better choice than the Planning Coordinator for the design of the UFLS programs. The Transmission Planner is more knowledgeable about the how the load and generation interact and how best to model these impacts on the frequency.
Response: The SDT believes the Planning Coordinator is the appropriate applicable entity since design of an UFLS program requires a wide-area view. Since the Planning Coordinator must work closely with the Transmission Planners in performance of its role, the SDT believes ~~the Planning Coordinator is the appropriate applicable entity since~~ that the Transmission Planners' expertise will be utilized. ~~the Planning Coordinator (PC) by its very nature needs to have at a minimum as wide an area view as the Transmission Planner (TP) if not larger.~~ The Planning Coordinator is the Functional Model entity best equipped to model~~s take in account~~ adjacent ~~PC~~ areas which are needed to ~~perform~~ identify islands as well as simulate regional and inter-regional ~~simulations of~~ underfrequency events – detailed and localized views cannot do that. ~~In addition, the UFLS database that states pertinent modeling information is available to the PC as well as the TP.~~		
FirstEnergy Corp	No	We support the removal of the Transmission Owner with end-use Load connected to their Facilities. The Distribution Provider entity adequately covers all load that is subject to this standard. The Generator Owner should be added to better coordinate their frequency protection with UFLS.
Response: The SDT has removed the qualifier~~reference~~ to the ~~"~~Transmission Owners "with end-use Load connected to their Facilities where such end use load is not part of a Distribution Provider's load" in the Applicability to be in line with commenters, the Compliance Registry Guidelines, the Functional Model and the NERC Glossary. The standard ~~is still applicable to~~ does not preclude arrangements between Distribution Providers and Transmission Owners to ~~cover the situation where~~ provide load shedding ~~is provided~~ at transmission voltage levels. This standard has not included requirements for Generator Owners since such requirements have been grouped with other generator requirements in PRC-024 ~~now~~ which was posted in February 2009 and presently is under development~~, being coordinated with this standard and previously posted~~. The SDT has coordinated development of this standard with the Generator Verification Standard Drafting Team (GV SDT) and will continue to do so to ensure coordination between the UFLS program requirements and the generator requirements.		
CenterPoint Energy		
Independent	No	We do not agree with the SDT to remove the Regional Entities from being assigned requirements on the basis that: ?? the

Organization	Yes or No	Question 1b Comments:
Electricity System Operator		Regional Entities are not user, owners, or operators of the Bulk Electric System and should not be assigned responsibility for requirements. There are a number of existing standards, for examples: CIP standards, BAL-002, EOP-004, EOP-007, FAC-013, FAC-012, to name a few, that hold the Regional Entities (Regional Reliability Organizations, as written) responsible for standard requirements. Unless and until an assessment is conducted to conclude that all such requirements can be replaced with an alternative responsible entity(ies), we do not see a problem with the Regional Entities being held responsible for complying with standards.The way the requirements are assigned in this draft standard (each group of Planning Coordinators shall) leaves room for confusion to the industry and debates in the compliance audit process. Unless the Group of PCs is registered as an entity, we are unable to see how the pertinent requirements can be legally enforced. An alternative is to assign these requirements to the Regional Entities, OR, develop a requirement for each PC to have an agreement with its Regional Entity to engage in the design of a UFLS program and coordinate settings with other PCs programs to achieve consistent application across the region. This way, the requirements can be written to hold Each Planning Coordinator rather than Each group of Planning Coordinators. If this approach is adopted, R1 and R2 could be combined as follows:R1. Each Planning Coordinator shall have an agreement with its Regional Entity to participate with other Planning Coordinators within the region in coordinating the design of an underfrequency load shedding program for consistent application across the region.With this change, R3 may be combined with R1 or be a separate requirement holding each PC responsible for engaging in the development of the criteria.And R3 to R8 can be revised to ?Each Planning Coordinator, in meeting the intent of R1, shall??The proposed changes provide clarity to the PC?s responsibility and removes gray areas in the compliance audit process.

Response: THIS RESPOSE WILL NEED STATEMENTS BY NERC/FERC STAFFS TO CONFIRM THE SDT DIRECTION AS WELL AS A REASON WHY SOME APPROVED STANDARDS STILL REFER TO RROs.

Response: A Precedent for ~~T~~the "group" ~~precedent~~ approach ~~had~~ already has been developed and used in the current FERC approved BAL-002-0 which states requirements and compliance elements that direct responsibility to a Reserve Sharing Group composed of Balancing Authorities. In addition the "group" concept was first proven under the predecessor Phase 1 through 3 field testing standards procedure in the early 2000s. The purpose is to exert peer pressure on all individual responsible entities by judging the results of the group effort. This is apparent in the development of simulation model base cases for the Eastern Interconnection. In the event the overall program fails to meet the performance characteristics, each member of the group is deemed non-compliant.

Organization	Yes or No	Question 1b Comments:
Xcel Energy	No	We feel 4.3 should be removed. Additionally, we feel that the informal formation of a group for the Planning Coordinators in non-RTO areas is problematic. We feel a new registered entity should be created, perhaps called the Planning Coordinator Group. This group would develop a governing document that spells out roles, responsibilities, etc. like a Reserve Sharing Group does. We feel this approach would best resolve issues surrounding coordination, compliance audits, entity identification in situations of potential non-compliance, penalty assessment, etc. The individual Planning Coordinators would still be required to join a group in their region, per R1. But, the remainder of the requirements should only refer to the Planning Coordinator Group.If the Regional Entity is not going to play a role in coordinating the Planning Coordinators, then we are unsure how an entity would join a

Organization	Yes or No	Question 1b Comments:
		group or attach itself to a group. We feel that in non-RTO areas, the Regional Entity should at least serve as a single point of contact for all Planning Coordinators in that region.

Response: The SDT has removed the qualifier~~reference~~ to the ~~"~~Transmission Owners "with end-use Load connected to their Facilities where such end use load is not part of a Distribution Provider's load" in the Applicability to be in line with commenters, the Compliance Registry Guidelines, the Functional Model and the NERC Glossary. The standard ~~is still applicable to~~ does not preclude arrangements between Distribution Providers and Transmission Owners to ~~cover the situation where~~ provide load shedding ~~is provided~~ at transmission voltage levels.

~~-~~A precedent for ~~T~~the "group" ~~precedent~~ approach ~~had~~ already has been developed and used in the current FERC approved BAL-002-0 which states requirements and compliance elements that direct responsibility to a Reserve Sharing Group composed of Balancing Authorities. In addition the "group" concept was first proven under the predecessor Phase 1 through 3 field testing standards procedure in the early 2000s. The purpose is to exert peer pressure on all individual responsible entities by judging the results of the group effort. This is apparent in the development of simulation model base cases for the Eastern Interconnection. In the event the overall program fails to meet the performance characteristics, each member of the group is deemed non-compliant.

2. **The SDT has strived to draft the applicability in a manner that includes all load while avoiding assigning applicability to more than one entity for the same load. The Functional Model indicates the Distribution Provider is not defined by a specific voltage, but rather as performing the Distribution function at any voltage. Considering the Functional Model definition of Distribution Providers please indicate whether you believe it is necessary to assign applicability to "Transmission Owners with end-use Load connected to their Facilities where such end-use load is not part of a Distribution Provider's load".**

Summary Consideration:

1. The SDT has removed the reference to the "Transmission Owners with end-use Load connected to their Facilities where such end use load is not part of a Distribution Provider's load" in the Applicability. Industry comments were divided between support for retaining this reference to ensure that all load is covered by a UFLS program and deleting this reference based on definitions in ~~to be in line with commenters,~~ the Compliance Registry ~~Guidelines~~ Criteria, the Functional Model, and the NERC Glossary. The SDT believes these definitions are clear that "Transmission Owners with end-use Load connected to their Facilities" should be registered as Distribution Providers and that all load will be covered by a UFLS program with this change. The SDT also notes that the standard ~~is still applicable to~~ does not preclude arrangements between Distribution Providers and Transmission Owners to ~~cover the situation where~~ provide load shedding ~~is provided~~ at transmission voltage levels.
2. ~~From a practical standpoint, automatic UFLS tripping at 100kV or above is just not the normal – much of the UFLS tripping is initiated at less than 100kV.~~ Since the Distribution Provider (DP) is the entity that connects end-user load to the electrical system, making the Distribution Provider the applicable entity will ensure all load is covered. This is confirmed by the Functional Model and the interim changes made to the NERC Compliance Registry Guidelines. While the standard assigns responsibility to the Distribution Provider it is not prescriptive in defining how the load shedding is to be implemented. The standard ~~already allows~~ does not preclude aggregation by the Distribution Providers ~~and~~ or arrangements with Transmission Owners for tripping at different voltage levels on different systems~~, but still holds the DP as the responsible entity~~.

Organization	Yes or No	Question 2 Comments:

Organization	Yes or No	Question 2 Comments:
TRE UFLS Standard Drafting Team	Yes	The TRE UFLS SDT believes the applicable entities provided for in the proposed standard are appropriate. However, the TRE UFLS SDT believes that the only group that may not be clearly understood to have assigned applicability are self-served customers that can shut down generation and pull from the grid without activating their own underfrequency load shedding. Assigning applicability to Transmission Owners with end-use load may make this clearer but we are not sure it is clear enough for self-served industrials. Additional specific wording to address this may be needed.
Response: The SDT has removed the reference to the "Transmission Owners with end-use Load connected to their Facilities where such end use load is not part of a Distribution Provider's load" in the Applicability to be in line with commenters, the Compliance Registry Guidelines, the Functional Model and the NERC Glossary. The SDT does not believe that including Transmission Owners in the Applicability clarifies responsibilities for self-served customers. The SDT believes that, from a NERC Reliability Standard perspective, such customers must be addressed and included in an effective UFLS program. The SDT is unaware of any provision for such customers to be exempt from functional registration by the Regional Entity. With regard to coordination of generation tripping by frequency level or with regard to load tripping by frequency level, such installations are equally important with regard to their potential impact upon the reliability of the bulk power system.		
Pepco Holdings, Inc - Affiliates	Yes	PHI agrees that including the Transmission Owners with end-use Load connected to their Facilities where such end use load is not part of a Distribution Provider's load eliminates the ambiguity that could result if Transmission Owners were not included in the Applicability list.
Response: The SDT has removed the reference to the "Transmission Owners with end-use Load connected to their Facilities where such end use load is not part of a Distribution Provider's load" in the Applicability to be in line with commenters, the Compliance Registry Guidelines, the Functional Model and the NERC Glossary. The standard ~~is still applicable to~~ does not preclude arrangements between Distribution Providers and Transmission Owners to ~~cover the situation where~~ provide load shedding ~~is provided~~ at transmission voltage levels.		
Bonneville Power Administration	Yes	It addresses DSI and other large loads that are directly connected to the BES.
Response: The SDT has removed the reference to the "Transmission Owners with end-use Load connected to their Facilities where such end use load is not part of a Distribution Provider's load" in the Applicability to be in line with commenters, the Compliance Registry Guidelines, the Functional Model and the NERC Glossary. The standard ~~is still applicable to~~ does not preclude arrangements between Distribution Providers and Transmission Owners to ~~cover the situation where~~ provide load shedding ~~is provided~~ at transmission voltage levels.		
Northeast Power Coordinating Council	No	Based on the definition of Distribution Provider in the Functional Model we believe that the applicability should be limited to Distribution Providers. All load should be accounted for by a registered Distribution Provider. The standard should not be written to correct for deficiencies resulting from incorrect registration of entities, and proper registration is vital to the

Organization	Yes or No	Question 2 Comments:
		reliability of the UFLS program.
Response: The SDT has removed the reference to the “Transmission Owners with end-use Load connected to their Facilities where such end use load is not part of a Distribution Provider’s load” in the Applicability to be in line with commenters, the Compliance Registry Guidelines, the Functional Model and the NERC Glossary. The standard ~~is still applicable to~~ does not preclude arrangements between Distribution Providers and Transmission Owners to ~~cover the situation where~~ provide load shedding ~~is provided~~ at transmission voltage levels.		
Southern Company	No	The applicability should be assigned to the TO only (not to DP). The Transmission Owner (TO) is the most appropriate entity to be responsible for implementation of the UFLS scheme. The TO generally has a wider area of responsibility, thus ensuring all load would be included in the implementation. This approach would allow the Distribution Providers (DP) to participate, if they choose, to implement the UFLS scheme providing the most selective load tripping, while at the same time, allowing for more efficient aggregation of smaller DPs' load into the overall scheme.
Response: ~~From a practical standpoint, automatic UFLS tripping at 100kV or above is just not the normal – much of the UFLS tripping is initiated at less than 100kV.~~ Since the Distribution Provider (DP) is the entity that connects end-user load to the electrical system, making the Distribution Provider the applicable entity will ensure all load is covered. This is confirmed by the Functional Model and the interim changes made to the NERC Compliance Registry Guidelines. While the standard assigns responsibility to the Distribution Provider it is not prescriptive in defining how the load shedding is to be implemented. The standard ~~already allows~~ does not preclude aggregation by the Distribution Providers ~~and~~ or arrangements with Transmission Owners for tripping at different voltage levels on different systems~~, but still holds the DP as the responsible entity~~.		
ERCOT ISO	Yes	All loads within the region should be accounted for when designing an UFLS program.
Response: The SDT agrees and had intended that all load be covered. The SDT has removed the reference to the “Transmission Owners with end-use Load connected to their Facilities where such end use load is not part of a Distribution Provider’s load” in the Applicability to be in line with commenters, the Compliance Registry Guidelines, the Functional Model and the NERC Glossary. The standard does not preclude arrangements between Distribution Providers and ~~is still applicable to~~ Transmission Owners to ~~cover the situation where~~provide load shedding ~~is provided~~ at transmission voltage levels.		
Electric Market Policy	No	The definition of Distribution Provider is adequate.
Response: The SDT has removed the reference to the “Transmission Owners with end-use Load connected to their Facilities where such end use load is not part of a Distribution Provider’s load” in the Applicability to be in line with commenters, the Compliance Registry Guidelines, the Functional Model and the NERC Glossary. The standard does not preclude arrangements between Distribution Providers and ~~is still applicable~~ to Transmission Owners to ~~cover the situation where~~ provide load shedding ~~is provided~~ at transmission voltage levels.		
Midwest ISO Stakeholders	No	We do not believe it is necessary to assign applicability to Transmission Owners with end-use Load connected to their Facilities where such end-use load is not part of the Distribution Providers load. We believe this clause is describing a

Organization	Yes or No	Question 2 Comments:
Standards Collaborators		distribution provider and these TOs should be registered as DPs. Furthermore, Standards should not attempt to create new classifications of registered entities. This is the function of the compliance registration process.
Response: The SDT has removed the reference to the “Transmission Owners with end-use Load connected to their Facilities where such end use load is not part of a Distribution Provider’s load” in the Applicability to be in line with commenters, the Compliance Registry Guidelines, the Functional Model and the NERC Glossary. The standard does not preclude arrangements between Distribution Providers and ~~is still applicable to~~ Transmission Owners to ~~cover the situation where~~ provide load shedding ~~is provided~~ at transmission voltage levels. **Assuming the commenter is referring to the “group of Planning Coordinators” as a new classification, the SDT believes that a new category is not required since the standard simply points to each Planning Coordinator working together as a group. As such each shares group responsibility for fulfilling the task. A precedent for ~~T~~the “group” ~~precedent~~ approach ~~had~~ already has been developed and used in the current FERC approved BAL-002-0 which states requirements and compliance elements that direct responsibility to a Reserve Sharing Group composed of Balancing Authorities. In addition the “group” concept was first proven under the predecessor Phase 1 through 3 field testing standards procedure in the early 2000s. The purpose is to exert peer pressure on all individual responsible entities by judging the results of the group effort. This is apparent in the development of simulation model base cases for the Eastern Interconnection. In the event the overall program fails to meet the performance characteristics, each member of the group is deemed non-compliant.**		
SERC UFLS Standards Drafting Team	No	The applicability should be assigned to the TO only (not to DP). The Transmission Owner (TO) is the most appropriate entity to be responsible for implementation of the UFLS scheme. The TO generally has a wider area of responsibility, thus ensuring all load would be included in the implementation. This approach would allow the Distribution Providers (DP) to participate if they choose to implement the UFLS scheme providing the most selective load tripping, while at the same time allowing for more efficient aggregation of smaller DPs' load into the overall scheme.
Response: ~~From a practical standpoint, automatic UFLS tripping at 100KV or above is just not the normal – much UFLS tripping is initiated at less than 100kV.~~ Since the Distribution Provider (DP) is the entity that connects end-user load to the electrical system, making the Distribution Provider the applicable~~ility~~ entity will ensure all load is covered. This is confirmed by the Functional Model and the interim changes made to the NERC Compliance Registry Guidelines. While the standard assigns responsibility to the Distribution Provider it is not prescriptive in defining how the load shedding is to be implemented. The standard ~~already allows~~ does not preclude aggregation by the Distribution Providers ~~and~~ or arrangements with Transmission Owners for tripping at different voltage levels on different systems~~, but still holds the DP as the responsible entity~~.		
FRCC Standards & Operations Departments	Yes	We believe that it is necessary to assign applicability to 'Load Serving Entities'. The Compliance Registry Criteria states: Load-serving entity is designated as the responsible entity for facilities that are part of a required underfrequency load shedding (UFLS) program designed, installed, and operated for the protection of the bulk power system.[pjt2] Therefore their applicability is appropriate.In addition we recommend adding a caveat within the applicability section that reads The TO, LSE or DP may meet these requirements through participation in an aggregated UFLS Program as permitted by

Organization	Yes or No	Question 2 Comments:
		the Regional UFLS program. This would allow smaller systems to aggregate load requirements and more effectively meet Regional UFLS requirements. Furthermore, we recommend an additional caveat within the applicability section that reads, "Compliance with an approved Regional Reliability Standard which defines the requirements of the Regional UFLS program satisfies the compliance requirements associated with this continent wide standard." This assumption can be made based on the defined attributes of a Regional Reliability Standard (i. e. Regional Reliability Standards go beyond, add detail to, or implement NERC Reliability Standards. Regional Reliability Standards shall not be inconsistent with or less stringent than NERC Reliability Standards.).
Response: Since the Distribution Provider (DP) is the entity that connects end-user load to the electrical system, making the Distribution Provider the applicable~~ility~~ entity will ensure all load is covered. This is confirmed by the Functional Model and the interim changes made to the NERC Statement of Compliance Registry Criteria. The interim changes were made to reflect concerns about the definition of the LSE as a "facility owning entity" as opposed to the Distribution Provider. As demonstrated in the NERC LSE workshop, currently approved Functional Model and the interim Registry Criteria changes, for standards purposes the DP is the "wires" connection to the electric system and owner of the UFLS tripping equipment. This may be inconsistent with previous usage of the same terms in some parts of the country. The Version 0 applicability for UFLS was set prior to the Registry and determined on the then general understanding of the Functional Model and industry usage. The current Functional Model is much clearer on this issue and designates the DP as the facility owner. Since NERC has stated that the Registry Criteria now has an interim step to correct the issue, it is expected that the Registry Criteria will change as the standards are re-evaluated for appropriateness. The SDT believes that this standard is in line with the direction taken by the interim changes and the approved Functional Model. **The standard ~~already allows~~ does not preclude aggregation by the Distribution Providers ~~and~~ or arrangements with Transmission Owners for tripping at different voltage levels on different systems~~, but still holds the DP as the responsible entity~~.** **The applicability of one standard does not reference another; each standard when approved by FERC stands on its own merit. This standard allows the development of a regional standard. It is up to the region to decide whether a regional standard can be justified or if a regional variance is appropriate. The SDT is ready to consider and accept any regional requests for variances.**		
Florida Municipal Power Agency and Select Members	Yes	Yes, we agree, but, want to be sure the implications are understood. As written, it would seem that the proposed language would make Transmission Owners responsible for adding up the load connected to their system, and if the total load scheduled to trip by UFLS does not meet the percentage of total load connected to that TO required, then, the TO would seem to be the ones responsible for making up the difference. We have to call into question whether capturing all of the load is worth the effort and whether it truly makes a significant difference to the reliability of the Bulk Electric System.We would suggest the added flexibility of including Load Serving Entities (LSEs) to the applicability section as well as including the ability for LSEs to represent multiple Distribution Providers. The Compliance Registry Criteria states: Load-serving entity is designated as the responsible entity for facilities that are part of a required underfrequency load shedding (UFLS) program designed, installed, and operated for the protection of the bulk power system. Therefore their applicability is appropriate.In addition we recommend adding the ability to aggregate within the applicability section that reads The LSE or

Organization	Yes or No	Question 2 Comments:
		DP may meet these requirements through participation in an aggregated UFLS Program. This would allow small systems to aggregate load requirements and more effectively meet Regional UFLS forecast load tripping requirements. The aggregation provides better resolution to the Regional plan requirements. Or alternatively, create a new function that allows aggregation similar to a Reserve Sharing Group.
Response: The SDT has changed the reference to the Transmission Owner to the Distribution Provider to be in line with commenters, the Compliance Registry Guidelines, the Functional Model and the NERC Glossary. ~~SDT MUST AGREE TO THIS AT MEETING~~ **Since the Distribution Provider (DP) is the entity that connects end-user load to the electrical system, making the Distribution Provider the applicable~~ility~~ entity will ensure all load is covered. This is confirmed by the Functional Model and the interim changes made to the NERC Statement of Compliance Registry Criteria. The interim changes were made to reflect concerns about the definition of the LSE as a “facility owning entity” as opposed to the Distribution Provider. As demonstrated in the NERC LSE workshop, currently approved Functional Model and the interim Registry Criteria changes, for standards purposes the DP is the “wires” connection to the electric system and owner of the UFLS tripping equipment. This may be inconsistent with previous usage of the same terms in some parts of the country. The Version 0 applicability for UFLS was set prior to the Registry and determined on general understanding of the Functional Model and industry usage. The current Functional Model is much clearer on this issue and designates the DP as the facility owner. Since NERC has stated that the Registry Criteria now has an interim step to correct the issue. It is expected that the Registry Criteria will change as the standards are re-evaluated for appropriateness. The SDT believes that this standard is in line with the direction taken by the interim changes and the approved Functional Model.** **~~-~~The standard ~~already allows~~ does not preclude aggregation by the Distribution Providers ~~and~~ or arrangements with Transmission Owners for tripping at different voltage levels on different systems~~, but still holds the DP as the responsible entity~~.** **~~The applicability of one standard does not reference another; each standard when approved by FERC stands on its own merit. This standard allows the development of a regional standard. It is up to the region to decide whether a regional standard can be justified or if a regional variance is appropriate. The SDT is ready to consider and accept any regional requests for variances.~~**		
MRO NERC Standards Review Subcommittee	No	The MRO NSRS believes that the definition of Distribution Provider assures that there are no gaps or holes in coverage of the applicable load. As noted in the response to Question 1, it is unnecessary to also assign applicability to Transmission Owners with end-use Load connected to their Facilities because according to the NERC Compliance Registry Criteria Rev 5.0 (Sections II.b and III.b.2) these entities must register as a Distribution Provider or transfer the responsibility for applicable UFLS requirements to a registered Distribution Provider by written agreement.
Response: The SDT has removed the reference to the “Transmission Owners with end-use Load connected to their Facilities where such end use load is not part of a Distribution Provider’s load” in the Applicability to be in line with commenters, the Compliance Registry Guidelines, the Functional Model and the NERC Glossary. The standard does not preclude arrangements between Distribution Providers and ~~is still applicable to~~ Transmission Owners to ~~cover the situation where~~ provide load shedding ~~is provided~~ at transmission voltage levels.		
Kansas City Power &	No	No, it is not necessary to include Transmission Provider with end-use load.

Organization	Yes or No	Question 2 Comments:
Light		
Response: The SDT has removed the reference to the "Transmission Owners with end-use Load connected to their Facilities where such end use load is not part of a Distribution Provider's load" in the Applicability to be in line with commenters, the Compliance Registry Guidelines, the Functional Model and the NERC Glossary. The standard ~~is still applicable to~~ does not preclude arrangements between Distribution Providers and Transmission Owners to ~~cover the situation where~~ provide load shedding ~~is provided~~ at transmission voltage levels.		
IRC Standards Review Comittee	No	NERC standards and requirements should not attempt to further define the functional entities. For those transmission owners that have facilities that meet the NERC definition of Distribution Provider, they should be registered in the compliance registry as such. If the interpretation of the current definition is that it does not include Transmission Owners with end-use Load connected to their facilities, we recommend the definition of Distribution Provider be updated.The Functional Model does not preclude assigning this responsibility to the Transmission Owners with end-use Load connected to their facilities where such end-use load is not part of a Distribution Provider's load. Excerpt from Chapter 14 of the Version 4 Functional Model Technical Document, below, describes this process:[When a Transmission Operator sees a need for non-voluntary load curtailment to relieve transmission constraints, such as an actual or expected exceedance of an operating limit, it implements load shedding that is under its control, or directs a Distribution Provider to physically implement the curtailment.]Loads that are connected to the transmission facilities and where such loads are not part of the DP's loads can and should be curtailed by the TOP action (to relieve constraints) or by the UFLS relays provided by the TOs (to arrest frequency decline).If the SDT is still undecided on this issue, we suggest the SDT consult the FMWG
Response: The SDT has removed the reference to the "Transmission Owners with end-use Load connected to their Facilities where such end use load is not part of a Distribution Provider's load" in the Applicability to be in line with commenters, the Compliance Registry Guidelines, the Functional Model and the NERC Glossary. The standard ~~is still applicable to~~ does not preclude arrangements between Distribution Providers and Transmission Owners to ~~cover the situation where~~ provide load shedding ~~is provided~~ at transmission voltage levels.		
Cowlitz County PUD	Yes	Yes, but for a different reason: many times the TO will be the owner of the UFLS equipment (e.g. Bonneville Power Administration), not the DP. There are many DP's who do not own UFLS equipment and should not be forced in this position if there is a willing TO to take on the responsibility.
Response: The SDT has removed the reference to the "Transmission Owners with end-use Load connected to their Facilities where such end use load is not part of a Distribution Provider's load" in the Applicability to be in line with commenters, the Compliance Registry Guidelines, the Functional Model and the NERC Glossary. The SDT has based the applicability in the standard on the functions performed by each entity. Where equipment may be owned by a Transmission Owner, ~~T~~the standard ~~is still applicable to~~ does not preclude arrangements between the Distribution Provider and Transmission Owners to ~~cover the situation where~~ provide load shedding ~~is provided~~ at transmission voltage levels. **~~From a practical standpoint, automatic UFLS tripping at 100kV or above is just not the normal – much of the UFLS tripping is initiated at less than 100kV. Since the Distribution Provider (DP) is the entity that connects end-user load to the electrical system, making the DP applicable will ensure all load is~~**		

Organization	Yes or No	Question 2 Comments:
~~covered. This is confirmed by the Functional Model and the interim changes made to the NERC Compliance Registry Guidelines. The standard already allows aggregation by the DPs and arrangements for tripping at different voltage levels on different systems, but still holds the DP as the responsible entity.~~		
Edward C. Stein		
Colmac Clarion	Yes	
City of Bedford	Yes	
Alabama Municipal Electric Authority	Yes	
US Army Corps of Engineers	Yes	
NIPSCO	Yes	
Public Service Electric and Gas Company	No	The Distribution Provider can in most cases identify all the load that is included in the UFLS Program.
Response: The SDT has removed the reference to the "Transmission Owners with end-use Load connected to their Facilities where such end use load is not part of a Distribution Provider's load" in the Applicability to be in line with commenters, the Compliance Registry Guidelines, the Functional Model and the NERC Glossary. The standard ~~is still applicable to~~ does not preclude arrangements between Distribution Providers and Transmission Owners to ~~cover the situation where~~ provide load shedding ~~is provided~~ at transmission voltage levels. **~~From a practical standpoint, automatic UFLS tripping at 100kV or above is just not the normal – much of the UFLS tripping is initiated at less than 100kV. Since the Distribution Provider (DP) is the entity that connects end-user load to the electrical system, making the DP applicable will ensure all load is covered. This is confirmed by the Functional Model and the interim changes made to the NERC Compliance Registry Guidelines. The standard already allows aggregation by the DPs and arrangements for tripping at different voltage levels on different systems, but still holds the DP as the responsible entity.~~**		
Central Lincoln	No	But please see Q1b comments.
Response:		

Organization	Yes or No	Question 2 Comments:
SPP System Protection and Control Working Group	No	For those transmission owners that have facilities that meet the NERC definition of Distribution Provider, they should be registered in the compliance registry as such.
Response: The SDT has removed the reference to the "Transmission Owners with end-use Load connected to their Facilities where such end use load is not part of a Distribution Provider's load" in the Applicability to be in line with commenters, the Compliance Registry Guidelines, the Functional Model and the NERC Glossary. The standard ~~is still applicable to~~ does not preclude arrangements between Distribution Providers and Transmission Owners to ~~cover the situation where~~ provide load shedding ~~is provided~~ at transmission voltage levels.		
Long island power Authority	No	
Exelon	Yes	Need to verify all end use load participates regardless of supply voltage level.
Response: The SDT had intended that all load be covered. The SDT has removed the reference to the "Transmission Owners with end-use Load connected to their Facilities where such end use load is not part of a Distribution Provider's load" in the Applicability to be in line with commenters, the Compliance Registry Guidelines, the Functional Model and the NERC Glossary. The standard ~~is still applicable to~~ does not preclude arrangements between Distribution Providers and Transmission Owners to ~~cover the situation where~~ provide load shedding ~~is provided~~ at transmission voltage levels. **~~From a practical standpoint, automatic UFLS tripping at 100kV or above is just not the normal – much of the UFLS tripping is initiated at less than 100kV. Since the Distribution Provider (DP) is the entity that connects end-user load to the electrical system, making the DP applicable will ensure all load is covered. This is confirmed by the Functional Model and the interim changes made to the NERC Compliance Registry Guidelines. The standard already allows aggregation by the DPs and arrangements for tripping at different voltage levels on different systems, but still holds the DP as the responsible entity.~~**		
ReliabilityFirst Corporation	Yes	
Arkansas Electric Cooperative Corporation	Yes	
System Protection & Control	Yes	
Duke Energy		

Organization	Yes or No	Question 2 Comments:
ReliabilityFirst	No	The Transmision Owner with end use load connected ... is out of line with the NERC Functional Model knowing that if a Transmision Owner has end use load connected, by definition, the Transmision Owner must register as a Distribution Provider. Therefore, using just the Distribution Provider in the UFLS standard is adequate and complete.
Response: The SDT has removed the reference to the "Transmission Owners with end-use Load connected to their Facilities where such end use load is not part of a Distribution Provider's load" in the Applicability to be in line with commenters, the Compliance Registry Guidelines, the Functional Model and the NERC Glossary. The standard ~~is still applicable to~~ does not preclude arrangements between Distribution Providers and Transmission Owners to ~~cover the situation where~~ provide load shedding ~~is provided~~ at transmission voltage levels.		
Illinois Municipal Electric Agency	No	IMEA believes it is not necessary to assign applicability to the TO function since the NERC Statement of Compliance Registry Criteria (Revision 5.0) already specifies that for end-use customers who are served at transmission voltages, the TO also serves as the DP (i.e., such a TO should already be registered as a DP).
Response: The SDT has removed the reference to the "Transmission Owners with end-use Load connected to their Facilities where such end use load is not part of a Distribution Provider's load" in the Applicability to be in line with commenters, the Compliance Registry Guidelines, the Functional Model and the NERC Glossary. The standard ~~is still applicable to~~ does not preclude arrangements between Distribution Providers and Transmission Owners to ~~cover the situation where~~ provide load shedding ~~is provided~~ at transmission voltage levels.		
Hydro-Québec TransEnergie (HQT)	No	Based on the definition of Distribution Provider in the Functional Model we believe that the applicability should be limited to Distribution Providers. All load should be accounted for by a registered Distribution Provider. The standard should not be written to correct for deficiencies resulting from incorrect registration of entities, and proper registration is vital to the reliability of the UFLS program.
Response: The SDT has removed the reference to the "Transmission Owners with end-use Load connected to their Facilities where such end use load is not part of a Distribution Provider's load" in the Applicability to be in line with commenters, the Compliance Registry Guidelines, the Functional Model and the NERC Glossary. The standard ~~is still applicable to~~ does not preclude arrangements between Distribution Providers and Transmission Owners to ~~cover the situation where~~ provide load shedding ~~is provided~~ at transmission voltage levels.		
AEP	Yes	This is a useful method for identifying those TOs where this situation occurs, instead of making the standard unnecessarily apply to all TOs.
Response: The SDT has removed the reference to the "Transmission Owners with end-use Load connected to their Facilities where such end use load is not part of a Distribution Provider's load" in the Applicability to be in line with commenters, the Compliance Registry Guidelines, the Functional Model and the NERC Glossary. The standard ~~is still applicable to~~ does not preclude arrangements between Distribution Providers and Transmission Owners to ~~cover the situation where~~ provide load shedding ~~is provided~~ at transmission voltage levels.		

Organization	Yes or No	Question 2 Comments:
Ontario Power Generation	Yes	
We Energies	No	
PacifiCorp	Yes	The simulations done by a group of Planning Coordinators must include all load in designing the UFLS program. However, there should be no obligation that all entities be required to shed any of their load at any particular frequency as long as sufficient load is shed in the area under study. The UFLS program could exempt Distribution Providers with peak loads less than an agreed upon threshold from shedding any load as long as sufficient load is shed in the area under study.
Response: The SDT has removed the reference to the "Transmission Owners with end-use Load connected to their Facilities where such end use load is not part of a Distribution Provider's load" in the Applicability to be in line with commenters, the Compliance Registry Guidelines, the Functional Model and the NERC Glossary. Note that the proposed standard only requires that a Distribution Provider provide load tripping in accordance with the UFLS program designed by the Planning Coordinators in its region. The proposed standard does not preclude the group of Planning Coordinators from exempting Distribution Providers with peak loads less than an agreed upon threshold. The SDT believes such details are best addressed by the Planning Coordinators within each region to utilize existing expertise and accommodate existing practices where possible. ~~**From a practical standpoint, automatic UFLS tripping at 100kV or above is just not the normal – much of the UFLS tripping is initiated at less than 100kV. Since the Distribution Provider (DP) is the entity that connects end-user load to the electrical system, making the DP applicable will ensure all load is covered. This is confirmed by the Functional Model and the interim changes made to the NERC Compliance Registry Guidelines. The standard already allows aggregation by the DPs and arrangements for tripping at different voltage levels on different systems, but still holds the DP as the responsible entity.**~~		
NextEra Energy Resources, LLC		No comment.
American Transmission Company	No	As noted in the response to Question 1, per NERC Compliance Registry Criteria Rev. 5.0 (Sections II.b and III.b.2), any Transmission Owner with end-use load connected to their facilities must register as a Distribution Provider or transferred the responsibility for applicable UFLS requirements to a registered Distribution Provider by written agreement. So, all applicable end-use load will be covered by the standard and the assignment of applicability to Transmission Owners with end-use load connected to their facilties is superflous and redundant.
Response: The SDT has removed the reference to the "Transmission Owners with end-use Load connected to their Facilities where such end use load is not part of a Distribution Provider's load" in the Applicability to be in line with commenters, the Compliance Registry Guidelines, the Functional Model and the NERC Glossary. The standard ~~is still applicable to~~ does not preclude arrangements between Distribution Providers and Transmission Owners to ~~cover the situation where~~ provide load shedding ~~is provided~~ at transmission voltage levels.		

Organization	Yes or No	Question 2 Comments:
Luminant Power	Yes	
Ameren	Yes	There may be loads that have no association or relationship with a Distribution Provider that would allow their load to be interrupted and thus be considered for the UFLS program.
Response: The SDT has removed the reference to the "Transmission Owners with end-use Load connected to their Facilities where such end use load is not part of a Distribution Provider's load" in the Applicability to be in line with commenters, the Compliance Registry Guidelines, the Functional Model and the NERC Glossary. The standard ~~is still applicable to~~ does not preclude arrangements between Distribution Providers and Transmission Owners to ~~cover the situation where~~ provide load shedding ~~is provided~~ at transmission voltage levels. **~~From a practical standpoint, automatic UFLS tripping at 100kV or above is just not the normal – much of the UFLS tripping is initiated at less than 100kV. Since the Distribution Provider (DP) is the entity that connects end-user load to the electrical system, making the DP applicable will ensure all load is covered. This is confirmed by the Functional Model and the interim changes made to the NERC Compliance Registry Guidelines. The standard already allows aggregation by the DPs and arrangements for tripping at different voltage levels on different systems, but still holds the DP as the responsible entity.~~**		
FirstEnergy Corp	No	The Distribution Provider sufficiently covers the end-use load subject to UFLS requirements and we do not believe the Transmission Owner needs to be included within the applicability of this standard.
Response: The SDT has removed the reference to the "Transmission Owners with end-use Load connected to their Facilities where such end use load is not part of a Distribution Provider's load" in the Applicability to be in line with commenters, the Compliance Registry Guidelines, the Functional Model and the NERC Glossary. The standard ~~is still applicable to~~ does not preclude arrangements between Distribution Providers and Transmission Owners to ~~cover the situation where~~ provide load shedding ~~is provided~~ at transmission voltage levels.		
CenterPoint Energy	No	For many years, CenterPoint Energy has complied with regional UFLS criteria for distribution load tripping. CenterPoint Energy does not believe it is necessary to include any requirements within PRC-006 for applicability to Transmission Owners and, therefore, recommends deleting Transmission Owner from Requirements 9 and 10. CenterPoint Energy commends the SDT for addressing the difficult issue of Applicability. By definition, Transmission Owners do not serve any load, whether distribution voltage or end-use transmission voltage. There may also be legalities that can preclude a Transmission Owner from serving any load. It would be problematic for a Transmission Owner to determine what transmission end-use load to trip when such loads can be refineries, chemical plants, water plants, and national space agency facilities. Tripping of such loads may have environmental and safety impacts. In addition, a Transmission Owner may not have any ownership of a transmission voltage end-use facility, nor control over such a facility. CenterPoint Energy believes the NERC Functional Model correctly reflects that Distribution Providers, not Transmission Owners, would be the responsible entity for load tripping.

Organization	Yes or No	Question 2 Comments:
Response: The SDT has removed the reference to the "Transmission Owners with end-use Load connected to their Facilities where such end use load is not part of a Distribution Provider's load" in the Applicability to be in line with commenters, the Compliance Registry Guidelines, the Functional Model and the NERC Glossary. The standard ~~is still applicable to~~ does not preclude arrangements between Distribution Providers and Transmission Owners to ~~cover the situation where~~ provide load shedding ~~is provided~~ at transmission voltage levels. **~~From a practical standpoint, automatic UFLS tripping at 100kV or above is just not the normal – much of the UFLS tripping is initiated at less than 100kV. Since the Distribution Provider (DP) is the entity that connects end-user load to the electrical system, making the DP applicable will ensure all load is covered. This is confirmed by the Functional Model and the interim changes made to the NERC Compliance Registry Guidelines. The standard already allows aggregation by the DPs and arrangements for tripping at different voltage levels on different systems, but still holds the DP as the responsible entity.~~**		
Independent Electricity System Operator	Yes	We agree that it is necessary to assign applicability to Transmission Owners with end-use Load connected to their facilities where such end-use load is not part of a Distribution Providers load. This assignment is in principle consistent with the perceived process presented in the Functional Model pertaining to the Transmission Operator having a role to curtail loads that are under its control to relieve transmission constraint. Excerpt from Chapter 14 of the Version 4 Functional Model Technical Document, below, describes this process:[When a Transmission Operator sees a need for non-voluntary load curtailment to relieve transmission constraints, such as an actual or expected exceedence of an operating limit, it implements load shedding that is under its control, or directs a Distribution Provider to physically implement the curtailment.]Loads that are connected to the transmission facilities and where such loads are not part of the DPs loads can and should be curtailed by the TOP action (to relieve constraints) or by the UFLS relays provided by the TOs (to arrest frequency decline).
Response: The SDT has removed the reference to the "Transmission Owners with end-use Load connected to their Facilities where such end use load is not part of a Distribution Provider's load" in the Applicability to be in line with commenters, the Compliance Registry Guidelines, the Functional Model and the NERC Glossary. The standard ~~is still applicable to~~ does not preclude arrangements between Distribution Providers and Transmission Owners to ~~cover the situation where~~ provide load shedding ~~is provided~~ at transmission voltage levels. **~~From a practical standpoint, automatic UFLS tripping at 100kV or above is just not the normal – much of the UFLS tripping is initiated at less than 100kV. Since the Distribution Provider (DP) is the entity that connects end-user load to the electrical system, making the DP applicable will ensure all load is covered. This is confirmed by the Functional Model and the interim changes made to the NERC Compliance Registry Guidelines. The standard already allows aggregation by the DPs and arrangements for tripping at different voltage levels on different systems, but still holds the DP as the responsible entity.~~**		
Xcel Energy	No	We feel 4.3 should be removed.
Response: The SDT has removed the reference to the "Transmission Owners with end-use Load connected to their Facilities where such end use load is not part of a Distribution Provider's load" in the Applicability to be in line with commenters, the Compliance Registry Guidelines, the Functional Model		

Organization	Yes or No	Question 2 Comments:
and the NERC Glossary. The standard ~~is still applicable to~~ does not preclude arrangements between Distribution Providers and Transmission Owners to ~~cover the situation where~~ provide load shedding ~~is provided~~ at transmission voltage levels.		

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Consideration of Comments on the Second Draft of the Underfrequency Load Shedding Program Requirements — Project 2007-01

The Underfrequency Load Shedding Standard Drafting Team thanks all commenters who submitted comments on the UFLS Program Requirements. This document was posted for a 30-day public comment period from April 20, 2009 through May 21, 2009. The stakeholders were asked to provide feedback on the document through a special Electronic Standard Comment Form. There were 45 sets of comments, including comments from more than 120 different people from over 80 companies representing all of the 10 Industry Segments as shown in the table on the following pages.

http://www.nerc.com/filez/standards/Underfrequency_Load_Shedding.html

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, Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

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

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Brian Bartos	TRE UFLS Standard Drafting Team	X	X			X		X			

	Additional Member	Additional Organization	Region	Segment Selection
1.	Randy Jones	Calpine	ERCOT	5
2.	Raborn Reader	EPCO	ERCOT	NA
3.	Eddy Reece	Rayburn Country Electric Coop.	ERCOT	NA
4.	Barry Kremling	Guadalupe Valley Electric Coop.	ERCOT	NA
5.	Sergio Garza	Lower Colorado River Authority	ERCOT	5
6.	Steve Myers	ERCOT ISO	ERCOT	2
7.	Ken McIntyre	ERCOT ISO	ERCOT	2
8.	Dennis Kunkel	AEP	ERCOT	1
9.	Matt Pawlowski	NextEra	ERCOT	5

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2.	Group	Richard Kafka	Pepco Holdings, Inc - Affiliates	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	David O'Connor	Potomac Electric Power Co	RFC	1
2.	Dave Thorne	Potomac Electric Power Co	RFC	1
3.	Vic Davis	Delmarva Power & Light	RFC	1

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10

4. John Keller	Atlantic City Electric	RFC	1
5. Walt Blackwell	Potomac Electric Power Co	RFC	1
6. Alvin Depew	Potomac Electric Power Co	RFC	1

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3.	Group	Denise Koehn	Bonneville Power Administration	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Kelly Johnson	Transmission Customer Service Engineering	WECC	1
2. Greg Vasallo	Transmission Customer Service Engineering	WECC	1
3. Larry Furumasu	Transmission Planning	WECC	1

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ralph Rufrano	New York Power Authority	NPCC	5
2.	Alan Adamson	New York State Reliability Council	NPCC	10
3.	Greg Campoli	New York Independent System Operator	NPCC	2
4.	Roger Champagne	Hydro-Quebec TransEnergie	NPCC	2
5.	Kurtis Chong	Independent Electricity System Operator	NPCC	2
6.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
7.	Manuel Couto	National Grid	NPCC	1
8.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
9.	Brian Evans-Mongeon	Utility Services	NPCC	8
10.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
11.	Michael Gildea	Constellation Energy	NPCC	6
12.	Brian Gooder	Ontario Power Generation Incorporated	NPCC	5
13.	Kathleen Goodman	ISO - New England	NPCC	2
14.	David Kiguel	Hydro One Networks Inc.	NPCC	1
15.	Michael Lombardi	Northeast Utilities	NPCC	1
16.	Randy MacDonald	New Brunswick System Operator	NPCC	2
17.	Bruce Metruck	New York PowerAuthority	NPCC	6

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10

18.	Robert Pellegrini	The United Illuminating Company	NPCC	1
19.	Michael Schiavone	National Grid	NPCC	1
20.	Michael Sonnelitter	FPL Energy/NextEra Energy	NPCC	5
21.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
22.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
23.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
5.	Group	Jim Busbin	Southern Company	X		X		X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	J. T. Wood	Southern Company Services, Inc.	SERC	1
2.	Hugh Francis	Southern Company Services, Inc.	SERC	1
3.	Bill Shultz	Southern Company Services, Inc.	SERC	5
4.	Phil Winston	Georgia Power Company	SERC	3
5.	Jonathan Glidewell	Southern Company Services, Inc.	SERC	1
6.	Marc Butts	Southern Company Services, Inc.	SERC	1

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6.	Group	Ken McIntyre	ERCOT ISO		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Steve Myers	ERCOT ISO	ERCOT	2
2.	John Schmall	ERCOT ISO	ERCOT	

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7.	Group	Jalal Babik	Electric Market Policy	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Louis Slade		SERC	6
2.	Mike Garton		NPCC	5

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8.	Group	Jason L. Marshall	Midwest ISO Stakeholders Standards Collaborators		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Lee Kittleson	Otter Tail Power	MRO	1

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

	Additional Member	Additional Organization	Region	Segment Selection
2.	Michael Ayotte	ITC Holdings	RFC	1

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9.	Group	Bob Jones	SERC UFLS Standards Drafting Team	X									

	Additional Member	Additional Organization	Region	Segment Selection
1.	Rick Foster	Ameren Services Co.	SERC	1
2.	John O'Connor	Progress Energy Carolinas	SERC	1
3.	Pat Huntley	SERC Reliability Corp.	SERC	10
4.	Jonathan Glidewell	Southern Co. Services	SERC	1
5.	Tom Cain	TVA	SERC	1

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10.	Group	Peter A. Heidrich	FRCC Standards & Operations Departments										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Linda Campbell	Florida Reliability Coordinating Council	FRCC	10
2.	Eric Senkowicz	Florida Reliability Coordinating Council	FRCC	10

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
11.	Group	Frank Gaffney	Florida Municipal Power Agency and Select Members	X		X	X	X				X	

	Additional Member	Additional Organization	Region	Segment Selection
1.	Rich Kinas	Orlando Utilities Commission	FRCC	1, 3, 5
2.	Jim Howard	Lakeland Electric	FRCC	1, 3, 5
3.	Greg Woessner	Kissimmee Utilities Authority	FRCC	1, 3, 5
4.	Cairo Venegas	Fort Pierce Utilities	FRCC	1, 3, 5

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
12.	Group	Michael Brytowski	MRO NERC Standards Review Subcommittee										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Carol Gerou	MRO	MRO	10
2.	Neal Balu	WPS	MRO	3, 4, 5, 6
3.	Joe DePoorter	MGE	MRO	3, 4, 5, 6
4.	Ken Goldsmith	ALTW	MRO	4
5.	Jim Haigh	WAPA	MRO	1, 6

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10

6. Terry Harbour	MEC	MRO	1, 3, 5, 6
7. Joseph Knight	GRE	MRO	1, 3, 5, 6
8. Scott Nickels	RPU	MRO	3, 4, 5, 6
9. Dave Rudolph	BEPC	MRO	3, 4, 5, 6
10. Eric Ruskamp	LES	MRO	1, 3, 5, 6
11. Terry Bilke	MISO	MRO	2

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
13.	Group	Michael Gammon	Kansas City Power & Light	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Tim Hinken	Kansas City Power & Light	SPP	1, 3, 5, 6
2. Nick McCarty	Kansas City Power & Light	SPP	1, 3, 5, 6
3. Jerry Hatfield	Kansas City Power & Light	SPP	1, 3, 5, 6

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
14.	Group	Ben Li	IRC Standards Review Committee		X								

Additional Member	Additional Organization	Region	Segment Selection
1. James Castle	NYISO		2
2. Anita Lee	AESO		2
3. Charles Yeung	SPP		2
4. Bill Phillips	MISO		2
5. Matt Goldberg	ISO-NE		2
6. Steve Myers	ERCOT		2
7. Patrick Brown	PJM		2

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
15.	Individual	Russell A. Noble	Cowlitz County PUD			X							
16.	Individual	Edward C. Stein	Edward C. Stein - Self								X		
17.	Individual	Harvie Beavers	Colmac Clarion					X					
18.	Individual	Elvin Epting	City of Bedford			X							

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
19.	Individual	Ray Phillips	Alabama Municipal Electric Authority				X						
20.	Individual	Karl Bryan	US Army Corps of Engineers					X					
21.	Individual	Tom Nappi	NIPSCO	X		X		X					
22.	Individual	Kenneth D. Brown b/h Joseph Lalier, Design Engineer Electric Delivery Planning	Public Service Electric and Gas Company	X		X							
23.	Individual	Steve Alexanderson	Central Lincoln			X							
24.	Individual	Shawn Jacobs	SPP System Protection and Control Working Group	X	X	X							X
25.	Individual	Jonathan Appelbaum	Long island power Authority	X									
26.	Individual	Eric Mortenson	Exelon	X		X		X					
27.	Individual	Rao Somayajula	ReliabilityFirst Corporation										X
28.	Individual	Ronnie Frizzell	Arkansas Electric Cooperative Corporation				X						
29.	Individual	Greg Davis	System Protection & Control	X		X							
30.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
31.	Individual	Anthony Jablonski	Reliability First										X
32.	Individual	Bob Thomas, Kevin Wagner, Troy Fodor, Scott Robison	Illinois Municipal Electric Agency				X						

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
33.	Individual	Roger Champagne	Hydro-Québec TransEnergie (HQT)	X									
34.	Individual	Jim Sorrels	AEP	X		X		X	X				
35.	Individual	Vladimir Stanisic	Ontario Power Generation					X	X				
36.	Individual	Joe Springhetti	We Energies			X	X	X					
37.	Individual	Sandra Shaffer	PacifiCorp	X		X		X	X				
38.	Individual	Mike Sonnelitter	NextEra Energy Resources, LLC					X					
39.	Individual	Jason Shaver	American Transmission Company	X									
40.	Individual	Rick Terrill	Luminant Power					X					
41.	Individual	Kirit Shah	Ameren	X		X		X	X				
42.	Individual	Doug Hohlbaugh	FirstEnergy Corp	X		X	X	X	X				
43.	Individual	Armin Klusman	CenterPoint Energy	X									
44.	Individual	Dan Rochester	Independent Electricity System Operator		X								
45.	Individual	Alice Murdock	Xcel Energy	X		X		X	X				

1. **The UFLS programs typically have been developed within each Region by representatives from the vertically integrated utilities, Control Areas, power pools, etc. in that Region. The SDT initially proposed that all UFLS requirements be contained within regional UFLS standards to utilize specific expertise within the regions and recognize that UFLS programs can be successfully coordinated if they are designed to achieve the same system performance characteristics, even across interconnected regions. However, based on the rationale contained in the background, the SDT has developed a continent wide standard consistent with the historical practice that promotes the utilization of previous experience and expertise. As proposed, the continent-wide standard requires that all Planning Coordinators within a Region work together as a group to develop the UFLS program for that Region that conforms to the performance characteristics.**

    a. Do you agree that creating a continent wide standard preserves the intent of utilizing specific expertise within the regions to develop UFLS programs that meet common performance characteristics?

Summary Consideration:

Organization	Yes or No	Question 1a Comments:
TRE UFLS Standard Drafting Team	Yes	The Texas Regional Entity Underfrequency Load Shedding Standard Drafting Team (TRE UFLS SDT) is pleased to provide these comments. These comments reflect the consensus of this specific regional standard drafting team and do not reflect the position of the Texas Regional Entity or ERCOT. The TRE UFLS SDT agrees that the basic common characteristics associated with the proposed UFLS standard provides for an appropriate level of required coordination within and, where applicable, between regions.
Response:		
Pepco Holdings, Inc - Affiliates	Yes	The PHI Affiliates agree that the Planning Coordinators have their own expertise and access to the expertise of the TOs and DPs in their area.
Response:		
Bonneville Power Administration	Yes	The continent-wide standard is a MINIMUM. Regions may still apply a higher standard.
Response:		
Northeast Power	Yes	

Organization	Yes or No	Question 1a Comments:
Coordinating Council		
Southern Company	Yes	Southern Company agrees with the comments submitted by the SERC Region for all questions in this comment form. Submitted SERC responses are essentially replicated in the responses we submit for Southern Company for questions 1-8.**We agree that creating a continent wide standard will preserve the intent of utilizing specific expertise within the region to develop UFLS schemes. First of all, this approach will provide uniformity among the regions for developing UFLS schemes, as all the regions will follow consistent performance characteristics specified in the standard. At the same time, the regions will have the flexibility to develop their own requirements to meet their specific needs.
Response:		
ERCOT ISO	Yes	
Electric Market Policy	Yes	
Midwest ISO Stakeholders Standards Collaborators	Yes	
SERC UFLS Standards Drafting Team	Yes	We agree that creating a continent wide standard will preserve the intent of utilizing specific expertise within the region to develop UFLS schemes. First of all, this approach will provide uniformity among the regions for developing UFLS schemes, as all the regions will follow a consistent performance characteristics specified in the standard. At the same time, the regions will have the flexibility to develop their own requirements to meet their specific needs.
Response:		
FRCC Standards & Operations Departments	Yes	We agree with the concept of the development of a Regional UFLS program that conforms to the common performance characteristics contained in the draft standard; however it is not clear what constitutes a 'region'. The SDT has repeatedly used the capitalized version ('Region') of the word in all of the associated documents (i.e. background, comment form) and reverted back to lower case version (region) in the standard. We believe that 'region' should be defined in the standard and incorporated into the NERC Glossary of Terms. This will ensure that the appropriate scope is applied in the development of Regional UFLS programs.
Response:		

Organization	Yes or No	Question 1a Comments:
Florida Municipal Power Agency and Select Members	Yes	
MRO NERC Standards Review Subcommittee	Yes	
Kansas City Power & Light	Yes	
IRC Standards Review Comittee	No	By definition, a continent wide standard intends to direct all regions into a consistent requirement and requires regions with varying practices to agree to a single standard. We support the approach taken in PRC-006-01 that specifies only the upper and lower bounds of UFLS protection requirements. We believe this is a reasonable approach to establish continent-wide requirements and allow regional expertise to design their regional UFLS programs.We agree with the proposal to preserve the intent of utilizing specific expertise within the regions to develop UFLS programs, but do not agree with the applicability and the way the standard is written to hold the Group of Planning Coordinators responsible for the requirements. Please see our comments under Q1b
Response:		
Cowlitz County PUD	Yes	
Edward C. Stein	Yes	
Colmac Clarion	Yes	
City of Bedford	Yes	
Alabama Municipal Electric Authority	Yes	
US Army Corps of Engineers	Yes	The continent wide standard establishes the performance characteristics that must be met and requiring the PCs within a Region to develop the specifics allows the implementation of the Rel Stndrd to also include local variances and has the added benefit of maintaining planning expertise.

Organization	Yes or No	Question 1a Comments:
Response:		
NIPSCO	No	It really depends on how this is accomplished.
Response:		
Public Service Electric and Gas Company	Yes	The creation of a continent wide standard is acceptable as long as the responsibility for developing a UFLS program remains with the Planning Coordinators/Authorities in the Regions.
Response:		
Central Lincoln	Yes	
SPP System Protection and Control Working Group	Yes	
Long island power Authority	Yes	
Exelon	Yes	
ReliabilityFirst Corporation	Yes	
Arkansas Electric Cooperative Corporation	Yes	
System Protection & Control	Yes	A continent wide standard will create desired system performance criteria, while allowing flexibility within the regions.
Response:		

Organization	Yes or No	Question 1a Comments:
Duke Energy	No	R2 requires consistent application across the region. As long as R6 is met, there should be no requirement for all systems within the region to be consistent. This will create unnecessary work to redesign systems that could meet R6 just because they are not consistent with other systems in the region. Recommend deleting the words consistent application across from R2. This is similar to not requiring the regions to be consistent as long as R6 is met.
Response:		
ReliabilityFirst	Yes	
Illinois Municipal Electric Agency	Yes	
Hydro-Québec TransEnergie (HQT)	Yes	
AEP	Yes	As each Reliability Coordinator has it's own UFLS requirements, the UFLS programs between the Reliability Coordinator's need to work together.
Response:		
Ontario Power Generation	Yes	
We Energies	No	We agree that a continent wide standard should be developed. However, we disagree with the approach taken with this draft of the standard. See our question 8 comments for more detail.
Response:		
PacifiCorp	Yes	PacifiCorp believes that the standard language is general enough to allow for regional differences. It is appropriate that the standard addresses what the parameters are, not how the parameters are to be implemented.
Response:		
NextEra Energy Resources, LLC	Yes	

Organization	Yes or No	Question 1a Comments:
American Transmission Company	Yes	
Luminant Power	Yes	
Ameren	No	It seems that regional standards with continent-wide performance characteristics would be the best mechanism to achieve this purpose. The only reason to have a continent wide standard to is to subscribe to the NERC process. There seems to be more focus on the process than the ultimate goal.
Response:		
FirstEnergy Corp	Yes	
CenterPoint Energy		
Independent Electricity System Operator	No	Further, we propose the scope of the standard be revised to clearly indicate that it focuses on the global events, as follows:To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency and assist recovery of frequency following widespread underfrequency events.
Response:		
Xcel Energy	Yes	

b. Do you agree that the SDT has assigned responsibility to the appropriate entity?

Summary Consideration:

Organization	Yes or No	Question 1b Comments:
TRE UFLS Standard Drafting Team	Yes	The TRE UFLS SDT believes specifically that data collection and assessments are most effectively carried out at the regional level. However, it is important to note one issue that will have to be dealt with in the regional standard and/or programs is how to account for the small load-serving systems (e.g., less than 25 MW) that are not NERC-registered.
Response:		
Pepco Holdings, Inc - Affiliates	Yes	
Bonneville Power Administration	Yes	BPA will have to have delegation agreements with DP's when BPA is covering their loads with BPA-UFLS relays or through other UFLS armed load in our BAA.
Response:		
Northeast Power Coordinating Council	No	We agree that the Planning Coordinator is the correct Functional Model entity based on having a wide-area view and the planning expertise to perform UFLS assessments. However, it is not clear to us whether applicability can be assigned to a group of Planning Coordinators as opposed to individual Planning Coordinators.
Response:		
Southern Company	No	No, because the Planning Coordinator(PC) role is implemented differently across the regions. The Transmission Planner(TP) is the most appropriate entity to design the UFLS scheme since the TP has the detailed system knowledge and is generally better positioned to develop the scheme.Also, the Transmission Owner (TO) is the most appropriate entity to be responsible for implementation of the UFLS scheme. The TO generally has a wider area of responsibility, thus ensuring all load would be included in the implementation. This approach would allow the Distribution Providers (DP) to participate if they choose to implement the UFLS scheme providing the most selective load tripping, while at the same time allowing for more efficient aggregation of smaller DPs' load into the overall scheme.

Organization	Yes or No	Question 1b Comments:
Response:		
ERCOT ISO	Yes	ERCOT ISO believes the Planning Coordinator is the correct responsible entity.
Response:		
Electric Market Policy	Yes	
Midwest ISO Stakeholders Standards Collaborators	No	We can understand the assignment of certain responsibilities to a Planning Coordinator. However, attempting to force Planning Coordinators to develop groups and then holding the entire group accountable for one another's compliance is unworkable.
Response:		
SERC UFLS Standards Drafting Team	No	No, because Planning Coordinator(PC) role is implemented differently across the regions. The Transmission Planner(TP) is the most appropriate entity to design the UFLS scheme since the TP has the detailed system knowledge and is generally better positioned to develop the scheme. Also, the Transmission Owner (TO) is the most appropriate entity to be responsible for implementation of the UFLS scheme. The TO generally has a wider area of responsibility, thus ensuring all load would be included in the implementation. This approach would allow the Distribution Providers (DP) to participate if they choose to implement the UFLS scheme providing the most selective load tripping, while at the same time allowing for more efficient aggregation of smaller DPs' load into the overall scheme.
Response:		
FRCC Standards & Operations Departments	No	Although we agree with the concept of the coordinated effort to design an underfrequency load shedding program, we believe that there is a need to establish an entity with the overall responsibility of coordinating the efforts of the Planning Coordinators. We recommend that the Regional Entity be responsible for overseeing the development of the Regional UFLS program while requiring the Planning Coordinators to participate in the process. Although the provided background material dismisses the idea of expanding the applicability to include the Regional Entity, the precedent has been established by assigning applicability to the Regional Entity in the CIP standards.
Response:		
Florida Municipal	No	While we agree that the responsibility resides with a regional planning coordinator type of Entity, a group of Planning

Organization	Yes or No	Question 1b Comments:
Power Agency and Select Members		Coordinators is a somewhat nebulous term and calls into question the enforceability of the standard, and therefore calls into question whether FERC will approve it or not. If the group of Planning Coordinators is noncompliant, who is noncompliant? Who negotiates settlement? Who would pay a potential fine? If one of the Entities does not provide data for the database required in R8, are all of the PCs noncompliant? As with nearly all things, in order to get something done, leadership is necessary, so, although this is certainly a team effort, one Entity ought to be designated to offer that leadership. Why not keep it the Regional Entity? Alternatively, is there sufficient justification to create a new function called the Regional Planning Coordinator? Or to change the definitions of Planning Coordinator, Transmission Planner and Resource Planner to essentially cause Transmission Planners and Resource Planners to focus on more local issues whereas the Planning Coordinator by definition becomes regional (and hence eliminates the need for the term a group of Planning Coordinators?)
Response:		
MRO NERC Standards Review Subcommittee	No	We agree with the assignment of selected responsibilities to the Planning Coordinator (PC) and suggest that the NERC Compliance Registry Criteria be revised to add the Planning Coordinator function and the Regional Entities be directed to register applicable entities to this function. Responsibility for several requirements are assigned to a "group" of Planning Coordinators. However, these groups do not presently exist and are not registered or legal entities. Perhaps a Planning Coordinator Group (PCG) should be added to the Applicability section and the NERC Compliance Registry Criteria be revised to add the PCG function, similar to the Reserve Sharing Group (RSG) function. Then, Regional Entities might be directed to register applicable entities to this function. Establishing PCGs would help PCs clarify how the group's responsibilities for compliance and liabilities would be assigned to each of its members.If a registered PCG function is not established, then drafting team should revise R1 to require all Planning Coordinators in a region to form a joint agreement to cover fulfillment of the subsequent UFLS requirements. See details in response to question 8.Transmission Owners function should be removed because it is unnecessary and redundant with the Distribution Provider function. Per NERC Compliance Registry Criteria Rev. 5.0 (Sections II.b and III.b.2), any Transmission Owner that provides and operates the ?wires? to end-use Load served at transmission voltages must register as a Distribution Provider or transfer the responsibility for applicable UFLS requirements to a registered Distribution Provider by written agreement. However, the TO function should be retained if SDT adopts the suggestion of adding R11 and R12 reguarding reactive power devices (in Q8).Generator Owners should be assigned responsibility for coordinating any generator off nominal frequency protection with any applicable UFLS relaying and for providing generator off nominal frequency protection information to the Planning Coordinator. So, the Generator Owner function should be added to the Applicability section. The SDT should coordinate with PRC-024 so that requirements do not overlap.
Response:		
Kansas City Power & Light	No	It is unnecessary to designate a Transmission Provider with end-use load. That is a Distribution Provider. Generator Owners should be added since generator data will be required to be provided for modeling purposes.

Organization	Yes or No	Question 1b Comments:
Response:		
IRC Standards Review Comittee	No	We do not agree with the SDT to remove the Regional Entities from being assigned requirements on the basis that: ?? the Regional Entities are not user, owners, or operators of the Bulk Electric System and should not be assigned responsibility for requirements.? There are a number of existing standards, for examples: CIP standards, BAL-002, EOP-004, EOP-007, FAC-013, FAC-012, to name a few, that hold the Regional Entities (Regional Reliability Organizations, as written) responsible for standard requirements. Unless and until an assessment is conducted to conclude that all such requirements can be replaced with an alternative responsible entity(ies), we do not see a problem with the Regional Entities being held responsible for complying with standards.The way the requirements are assigned in this draft standard (each group of Planning Coordinators shall) leaves room for confusion to the industry and debates in the compliance audit process. Unless the Group of PCs is registered as an entity, we are unable to see how the pertinent requirements can be legally enforced. An alternative is to assign these requirements to the Regional Entities, OR, develop a requirement for each PC to have an agreement with its Regional Entity to engage in the design of a UFLS program and coordinate settings with other PCs? programs to achieve consistent application across the region. This way, the requirements can be written to hold Each Planning Coordinator rather than Each group of Planning Coordinators. If this approach is adopted, R1 and R2 could be combined as follows:R1. Each Planning Coordinator shall have an agreement with its Regional Entity to participate with other Planning Coordinators within the region in coordinating the design of an underfrequency load shedding program for consistent application across the region.With this change, R3 may be combined with R1 or be a separate requirement holding each PC responsible for engaging in the development of the criteria.And R3 to R8 can be revised to ?Each Planning Coordinator, in meeting the intent of R1, shall?The proposed changes provide clarity to the PC?s responsibility and removes gray areas in the compliance audit process.
Response:		
Cowlitz County PUD	Yes	I would defer to the opinion of the Planning Coordinators, but am wondering why the RC is not involved. As far as the TO and DP responsibility I see no problem as long as it is clear what data and load tripping is required.
Response:		
Edward C. Stein	Yes	
Colmac Clarion	Yes	
City of Bedford	Yes	

Organization	Yes or No	Question 1b Comments:
Alabama Municipal Electric Authority	Yes	
US Army Corps of Engineers	Yes	
NIPSCO	Yes	The planning groups yes
Response:		
Public Service Electric and Gas Company	Yes	
Central Lincoln	No	"Transmission Owners with end-use Load connected to their Facilities where suchend use load is not part of a Distribution Providers load"TOs that meet the registry criteria for DP should be registered as such. If they don't meet the criteria, they are not required to have UFLS and this standard is not applicable to the small unregistered distribution system in question.Instead, I propose that TOs be included with no qualification, or a qualification that expresses the following situation: A DP and a TO may jointly decide the most effective location for UFLS may be on the TO's system, where it may be easier to reach the load shedding target. It would then be the TO that would be required to meet R9 and R10.
Response:		
SPP System Protection and Control Working Group	Yes	
Long island power Authority	Yes	
Exelon	No	GOs should be included as applicable entities because they play an important role in matching load and generation in periods of frequency excursion. That being said, the standard should not require the installation of under frequency relays at generators that would remain on line beyond these minimum requirements.

Organization	Yes or No	Question 1b Comments:
Response:		
ReliabilityFirst Corporation	Yes	
Arkansas Electric Cooperative Corporation	No	I agree with the Planning Coordinator Group concept but this group should be required to solicit the input from other functional entities such as the GO, TO, TOP, DP, and LSE when developing the criteria and plans. These other entities will have valuable insight as to what should and should not be included in the UFlS programs and need to have a voice during the development of these programs. I would suggest adding the following sentence to R2 and R3 "The design(R2)/criteria(R3)shall be developed taking into consideration the input and feedback from the Generator Owners, Transmission Owners, Transmission Operators, Distribution Providers and Load Serving Entities to which the design/critria shall apply." While the Distribution Provider may own the equipment the LSE will play a valuable role in determining which equipment should be used to shed load. The LSE and not necessarily the DP has a better knowledge of the load makeup served by the DP's equipment and thus may be in a better position to identify the best location for UF relays. For example the LSE would know if a circuit has a critical load where the DP may or may not have this knowledge. Since load is what is being dropped, the LSE is the best one to make the determation of which load is to be shed. The LSE may not need be an applicable entity but the UF programs and plans should not be developed without their input.It may be that the standard applicability needs to be expanded to these other entities by adding something to the effect of: GO, TO, TOP, DP, and LSE will participate in the development of the UFLS program and plans by providing input and feedback.
Response:		
System Protection & Control	Yes	
Duke Energy	No	The proposed standard’s requirements R1-R8 are applicable to Planning Coordinator, which isn’t a registered function in NERC’s compliance registry. Without applicability to a registered entity such as the Planning Authority or Transmission Planner, there is no clear responsibility for compliance. Also it is unclear how compliance can reasonably be enforced when responsibility is shared by a group of entities. It is not clear how non-compliance with R6 is addressed given that all PCs in the region are combined by R1. Somehow, each PC must be allowed to demonstrate compliance to the standard independently so compliant PCs are not penalized along with the non-compliant one(s).
Response:		
ReliabilityFirst	No	The Transmision Owner with end use load connected ... is out of line with the NERC Functional Model knowing that if a Transmision Owner has end use load connected, by definition, the Transmision Owner must register as a Distribution

Organization	Yes or No	Question 1b Comments:
		Provider. Therefore, using just the Distribution Provider in the UFLS standard is adequate and complete.
Response:		
Illinois Municipal Electric Agency		
Hydro-Québec TransEnergie (HQT)	No	HQT agree that the Planning Coordinator is the correct Functional Model entity based on having a wide-area view and the planning expertise to perform UFLS assessments. However, it is not clear whether applicability can be assigned to a group of Planning Coordinators as opposed to individual Planning Coordinator.
Response:		
AEP	No	Reliability Coordinators have set up specifics standards on the set points for UFLS. The proposed standard misses this circumstance by not including the Reliability Coordinator in the standard. How would this be reconciled?
Response:		
Ontario Power Generation	Yes	
We Energies	No	See our question 8 comments for more detail.
Response:		
PacifiCorp	Yes	While PacifiCorp agrees that coordination between Planning Coordinators is necessary in order to design and implement an effective UFLS program, it has some concern regarding the assignment of responsibility for compliance with this standard to a currently undefined group of Planning Coordinators. There is no such entity in the Functional Model and it is therefore unclear as to how this group will function and by whom it will be governed. The way the standard is currently drafted raises significant questions regarding how the requirements will be enforced, how a Planning Coordinator will know what group to participate in, how its participation in such group will be evaluated, how disagreements between group participants will be resolved, and which entity, among such group of Planning Coordinators, will be responsible for any potential violations. PacifiCorp recommends that either 1) the SDT assign the UFLS coordination responsibility and governance to the Regional Entity; or 2) the SDT re-draft the standard in such a way that allows Planning Coordinators to assign their compliance responsibility and activity to an agent Planning Coordinator Group similar to the group concept utilized in BAL-002-0 that

Organization	Yes or No	Question 1b Comments:
		allows Balancing Authorities to assign compliance responsibility to a Reserve Sharing Group.
Response:		
NextEra Energy Resources, LLC		No comment.
American Transmission Company	No	We agree with the assignment of selected responsibilities to the Planning Coordinator (PC) and suggest that NERC revise the Compliance Registry Criteria to add the Planning Coordinator and direct the Regional Entities to register applicable entities to this function. Responsibility for several requirements are assigned to a "group" of Planning Coordinators, but Planning Coordinator Group (PCG) does not appear in the list of applicable entities. We agree with leaving the PCG entity off of the list. However, without a PCG entity in the list, the applicable requirements should be reworded to make each Planing Coordinator individually responsible for their contribution to the group actions. Suggested wording for each applicable requirement is provided in the response to Question 8.If the drafting team decides to apply requirement responsiblities to a PCG, then NERC should revise the Compliance Registry Criteria to add the PSG and direct the Regional Entities to register the applicable entities to this function. Since regional PSGs have not been formed as legal entities in the past, then going this direction would require PC to establish contracts to form these groups in order to clearly define the compliance and sanction liabilities of each PC in the group. Transmission Owners should be removed because it is redundant with Distribution Provider. Per NERC Compliance Registry Criteria Rev. 5.0 (Sections II.b and III.b.2), any Transmission Owner that provides and operates the wires to end-use Load served at transmission voltages must register as a Distribution Provider or transferred the responsibility for applicable UFLS requirements to a registered Distribution Provider by written agreement. Therefore, we suggest the removal of Transmission Owner from the Applicability section.Generator Owners (GO) should be included in the Applicable entities section and requirements should be added that assign GOs the responsibility for providing generator off nominal frequency protection information to the Planning Coordinator and for coordinating any generator off nominal frequency protection with any applicable UFLS program.
Response:		
Luminant Power	Yes	
Ameren	No	It seems that the Transmission Planner would be a better choice than the Planning Coordinator for the design of the UFLS programs. The Transmission Planner is more knowledgeable about the how the load and generation interact and how best to model these impacts on the frequency.
Response:		

Organization	Yes or No	Question 1b Comments:
FirstEnergy Corp	No	We support the removal of the Transmission Owner with end-use Load connected to their Facilities. The Distribution Provider entity adequately covers all load that is subject to this standard. The Generator Owner should be added to better coordinate their frequency protection with UFLS.
Response:		
CenterPoint Energy		
Independent Electricity System Operator	No	We do not agree with the SDT to remove the Regional Entities from being assigned requirements on the basis that: ?? the Regional Entities are not user, owners, or operators of the Bulk Electric System and should not be assigned responsibility for requirements. There are a number of existing standards, for examples: CIP standards, BAL-002, EOP-004, EOP-007, FAC-013, FAC-012, to name a few, that hold the Regional Entities (Regional Reliability Organizations, as written) responsible for standard requirements. Unless and until an assessment is conducted to conclude that all such requirements can be replaced with an alternative responsible entity(ies), we do not see a problem with the Regional Entities being held responsible for complying with standards.The way the requirements are assigned in this draft standard (each group of Planning Coordinators shall) leaves room for confusion to the industry and debates in the compliance audit process. Unless the Group of PCs is registered as an entity, we are unable to see how the pertinent requirements can be legally enforced. An alternative is to assign these requirements to the Regional Entities, OR, develop a requirement for each PC to have an agreement with its Regional Entity to engage in the design of a UFLS program and coordinate settings with other PCs programs to achieve consistent application across the region. This way, the requirements can be written to hold Each Planning Coordinator rather than Each group of Planning Coordinators. If this approach is adopted, R1 and R2 could be combined as follows:R1. Each Planning Coordinator shall have an agreement with its Regional Entity to participate with other Planning Coordinators within the region in coordinating the design of an underfrequency load shedding program for consistent application across the region.With this change, R3 may be combined with R1 or be a separate requirement holding each PC responsible for engaging in the development of the criteria.And R3 to R8 can be revised to ?Each Planning Coordinator, in meeting the intent of R1, shall??The proposed changes provide clarity to the PC?s responsibility and removes gray areas in the compliance audit process.
Response:		
Xcel Energy	No	We feel 4.3 should be removed. Additionally, we feel that the informal formation of a group for the Planning Coordinators in non-RTO areas is problematic. We feel a new registered entity should be created, perhaps called the Planning Coordinator Group. This group would develop a governing document that spells out roles, responsibilities, etc. like a Reserve Sharing Group does. We feel this approach would best resolve issues surrounding coordination, compliance audits, entity identification in situations of potential non-compliance, penalty assessment, etc. The individual Planning Coordinators would still be required to join a group in their region, per R1. But, the remainder of the requirements should only refer to the

Organization	Yes or No	Question 1b Comments:
		Planning Coordinator Group.If the Regional Entity is not going to play a role in coordinating the Planning Coordinators, then we are unsure how an entity would join a group or attach itself to a group. We feel that in non-RTO areas, the Regional Entity should at least serve as a single point of contact for all Planning Coordinators in that region.
Response:		

2. **The SDT has strived to draft the applicability in a manner that includes all load while avoiding assigning applicability to more than one entity for the same load. The Functional Model indicates the Distribution Provider is not defined by a specific voltage, but rather as performing the Distribution function at any voltage. Considering the Functional Model definition of Distribution Providers please indicate whether you believe it is necessary to assign applicability to "Transmission Owners with end-use Load connected to their Facilities where such end-use load is not part of a Distribution Provider's load".**

Summary Consideration:

Organization	Yes or No	Question 2 Comments:
TRE UFLS Standard Drafting Team	Yes	The TRE UFLS SDT believes the applicable entities provided for in the proposed standard are appropriate. However, the TRE UFLS SDT believes that the only group that may not be clearly understood to have assigned applicability are self-served customers that can shut down generation and pull from the grid without activating their own underfrequency load shedding. Assigning applicability to Transmission Owners with end-use load may make this clearer but we are not sure it is clear enough for self-served industrials. Additional specific wording to address this may be needed.
Response:		
Pepco Holdings, Inc - Affiliates	Yes	PHI agrees that including the Transmission Owners with end-use Load connected to their Facilities where such end use load is not part of a Distribution Provider's load eliminates the ambiguity that could result if Transmission Owners were not included in the Applicability list.
Response:		
Bonneville Power Administration	Yes	It addresses DSI and other large loads that are directly connected to the BES.
Response:		
Northeast Power Coordinating Council	No	Based on the definition of Distribution Provider in the Functional Model we believe that the applicability should be limited to Distribution Providers. All load should be accounted for by a registered Distribution Provider. The standard should not be written to correct for deficiencies resulting from incorrect registration of entities, and proper registration is vital to the reliability of the UFLS program.

Organization	Yes or No	Question 2 Comments:
Southern Company	No	The applicability should be assigned to the TO only (not to DP). The Transmission Owner (TO) is the most appropriate entity to be responsible for implementation of the UFLS scheme. The TO generally has a wider area of responsibility, thus ensuring all load would be included in the implementation. This approach would allow the Distribution Providers (DP) to participate, if they choose, to implement the UFLS scheme providing the most selective load tripping, while at the same time, allowing for more efficient aggregation of smaller DPs' load into the overall scheme.
Response:		
ERCOT ISO	Yes	All loads within the region should be accounted for when designing an UFLS program.
Response:		
Electric Market Policy	No	The definition of Distribution Provider is adequate.
Response:		
Midwest ISO Stakeholders Standards Collaborators	No	We do not believe it is necessary to assign applicability to Transmission Owners with end-use Load connected to their Facilities where such end-use load is not part of the Distribution Providers load. We believe this clause is describing a distribution provider and these TOs should be registered as DPs. Furthermore, Standards should not attempt to create new classifications of registered entities. This is the function of the compliance registration process.
Response:		
SERC UFLS Standards Drafting Team	No	The applicability should be assigned to the TO only (not to DP). The Transmission Owner (TO) is the most appropriate entity to be responsible for implementation of the UFLS scheme. The TO generally has a wider area of responsibility, thus ensuring all load would be included in the implementation. This approach would allow the Distribution Providers (DP) to participate if they choose to implement the UFLS scheme providing the most selective load tripping, while at the same time allowing for more efficient aggregation of smaller DPs' load into the overall scheme.
Response:		
FRCC Standards & Operations Departments	Yes	We believe that it is necessary to assign applicability to 'Load Serving Entities'. The Compliance Registry Criteria states: Load-serving entity is designated as the responsible entity for facilities that are part of a required underfrequency load shedding (UFLS) program designed, installed, and operated for the protection of the bulk power system. Therefore their applicability is appropriate.In addition we recommend adding a caveat within the applicability section that reads The TO,

Organization	Yes or No	Question 2 Comments:
		LSE or DP may meet these requirements through participation in an aggregated UFLS Program as permitted by the Regional UFLS program. This would allow smaller systems to aggregate load requirements and more effectively meet Regional UFLS requirements.Furthermore, we recommend an additional caveat within the applicability section that reads, "Compliance with an approved Regional Reliability Standard which defines the requirements of the Regional UFLS program satisfies the compliance requirements associated with this continent wide standard." This assumption can be made based on the defined attributes of a Regional Reliability Standard (i. e. Regional Reliability Standards go beyond, add detail to, or implement NERC Reliability Standards. Regional Reliability Standards shall not be inconsistent with or less stringent than NERC Reliability Standards.).
Response:		
Florida Municipal Power Agency and Select Members	Yes	Yes, we agree, but, want to be sure the implications are understood. As written, it would seem that the proposed language would make Transmission Owners responsible for adding up the load connected to their system, and if the total load scheduled to trip by UFLS does not meet the percentage of total load connected to that TO required, then, the TO would seem to be the ones responsible for making up the difference. We have to call into question whether capturing all of the load is worth the effort and whether it truly makes a significant difference to the reliability of the Bulk Electric System.We would suggest the added flexibility of including Load Serving Entities (LSEs) to the applicability section as well as including the ability for LSEs to represent multiple Distribution Providers. The Compliance Registry Criteria states: Load-serving entity is designated as the responsible entity for facilities that are part of a required underfrequency load shedding (UFLS) program designed, installed, and operated for the protection of the bulk power system. Therefore their applicability is appropriate.In addition we recommend adding the ability to aggregate within the applicability section that reads The LSE or DP may meet these requirements through participation in an aggregated UFLS Program. This would allow small systems to aggregate load requirements and more effectively meet Regional UFLS forecast load tripping requirements. The aggregation provides better resolution to the Regional plan requirements. Or alternatively, create a new function that allows aggregation similar to a Reserve Sharing Group.
Response:		
MRO NERC Standards Review Subcommittee	No	The MRO NSRS believes that the definition of Distribution Provider assures that there are no gaps or holes in coverage of the applicable load. As noted in the response to Question 1, it is unnecessary to also assign applicability to Transmission Owners with end-use Load connected to their Facilities because according to the NERC Compliance Registry Criteria Rev 5.0 (Sections II.b and III.b.2) these entities must register as a Distribution Provider or transfer the responsibility for applicable UFLS requirements to a registered Distribution Provider by written agreement.
Response:		

Organization	Yes or No	Question 2 Comments:
Kansas City Power & Light	No	No, it is not necessary to include Transmission Provider with end-use load.
Response:		
IRC Standards Review Comittee	No	NERC standards and requirements should not attempt to further define the functional entities. For those transmission owners that have facilities that meet the NERC definition of Distribution Provider, they should be registered in the compliance registry as such. If the interpretation of the current definition is that it does not include Transmission Owners with end-use Load connected to their facilities, we recommend the definition of Distribution Provider be updated.The Functional Model does not preclude assigning this responsibility to the Transmission Owners with end-use Load connected to their facilities where such end-use load is not part of a Distribution Provider's load. Excerpt from Chapter 14 of the Version 4 Functional Model Technical Document, below, describes this process:[When a Transmission Operator sees a need for non-voluntary load curtailment to relieve transmission constraints, such as an actual or expected exceedance of an operating limit, it implements load shedding that is under its control, or directs a Distribution Provider to physically implement the curtailment.]Loads that are connected to the transmission facilities and where such loads are not part of the DP's loads can and should be curtailed by the TOP action (to relieve constraints) or by the UFLS relays provided by the TOs (to arrest frequency decline).If the SDT is still undecided on this issue, we suggest the SDT consult the FMWG
Response:		
Cowlitz County PUD	Yes	Yes, but for a different reason: many times the TO will be the owner of the UFLS equipment (e.g. Bonneville Power Administration), not the DP. There are many DP's who do not own UFLS equipment and should not be forced in this position if there is a willing TO to take on the responsibility.
Response:		
Edward C. Stein		
Colmac Clarion	Yes	
City of Bedford	Yes	
Alabama Municipal Electric Authority	Yes	

Organization	Yes or No	Question 2 Comments:
US Army Corps of Engineers	Yes	
NIPSCO	Yes	
Public Service Electric and Gas Company	No	The Distribution Provider can in most cases identify all the load that is included in the UFLS Program.
Response:		
Central Lincoln	No	But please see Q1b comments.
Response:		
SPP System Protection and Control Working Group	No	For those transmission owners that have facilities that meet the NERC definition of Distribution Provider, they should be registered in the compliance registry as such.
Response:		
Long island power Authority	No	
Exelon	Yes	Need to verify all end use load participates regardless of supply voltage level.
Response:		
ReliabilityFirst Corporation	Yes	
Arkansas Electric Cooperative Corporation	Yes	

Organization	Yes or No	Question 2 Comments:
System Protection & Control	Yes	
Duke Energy		
ReliabilityFirst	No	The Transmision Owner with end use load connected ... is out of line with the NERC Functional Model knowing that if a Transmision Owner has end use load connected, by definition, the Transmision Owner must register as a Distribution Provider. Therefore, using just the Distribution Provider in the UFLS standard is adequate and complete.
Response:		
Illinois Municipal Electric Agency	No	IMEA believes it is not necessary to assign applicability to the TO function since the NERC Statement of Compliance Registry Criteria (Revision 5.0) already specifies that for end-use customers who are served at transmission voltages, the TO also serves as the DP (i.e., such a TO should already be registered as a DP).
Response:		
Hydro-Québec TransEnergie (HQT)	No	Based on the definition of Distribution Provider in the Functional Model we believe that the applicability should be limited to Distribution Providers. All load should be accounted for by a registered Distribution Provider. The standard should not be written to correct for deficiencies resulting from incorrect registration of entities, and proper registration is vital to the reliability of the UFLS program.
Response:		
AEP	Yes	This is a useful method for identifying those TOs where this situation occurs, instead of making the standard unnecessarily apply to all TOs.
Response:		
Ontario Power Generation	Yes	
We Energies	No	
PacifiCorp	Yes	The simulations done by a group of Planning Coordinators must include all load in designing the UFLS program. However,

Organization	Yes or No	Question 2 Comments:
		there should be no obligation that all entities be required to shed any of their load at any particular frequency as long as sufficient load is shed in the area under study. The UFLS program could exempt Distribution Providers with peak loads less than an agreed upon threshold from shedding any load as long as sufficient load is shed in the area under study.
Response:		
NextEra Energy Resources, LLC		No comment.
American Transmission Company	No	As noted in the response to Question 1, per NERC Compliance Registry Criteria Rev. 5.0 (Sections II.b and III.b.2), any Transmission Owner with end-use load connected to their facilities must register as a Distribution Provider or transferred the responsibility for applicable UFLS requirements to a registered Distribution Provider by written agreement. So, all applicable end-use load will be covered by the standard and the assignment of applicability to Transmission Owners with end-use load connected to their facilties is superflous and redundant.
Response:		
Luminant Power	Yes	
Ameren	Yes	There may be loads that have no association or relationship with a Distribution Provider that would allow their load to be interrupted and thus be considered for the UFLS program.
Response:		
FirstEnergy Corp	No	The Distribution Provider sufficiently covers the end-use load subject to UFLS requirements and we do not believe the Transmission Owner needs to be included within the applicability of this standard.
Response:		
CenterPoint Energy	No	For many years, CenterPoint Energy has complied with regional UFLS criteria for distribution load tripping. CenterPoint Energy does not believe it is necessary to include any requirements within PRC-006 for applicability to Transmission Owners and, therefore, recommends deleting Transmission Owner from Requirements 9 and 10. CenterPoint Energy commends the SDT for addressing the difficult issue of Applicability. By definition, Transmission Owners do not serve any load, whether distribution voltage or end-use transmission voltage. There may also be legalities that can preclude a Transmission Owner from serving any load. It would be problematic for a Transmission Owner to determine what transmission end-use load to trip when such loads can be refineries, chemical plants, water plants, and national space

Organization	Yes or No	Question 2 Comments:
		agency facilities. Tripping of such loads may have environmental and safety impacts. In addition, a Transmission Owner may not have any ownership of a transmission voltage end-use facility, nor control over such a facility. CenterPoint Energy believes the NERC Functional Model correctly reflects that Distribution Providers, not Transmission Owners, would be the responsible entity for load tripping.
Response:		
Independent Electricity System Operator	Yes	We agree that it is necessary to assign applicability to Transmission Owners with end-use Load connected to their facilities where such end-use load is not part of a Distribution Providers load. This assignment is in principle consistent with the perceived process presented in the Functional Model pertaining to the Transmission Operator having a role to curtail loads that are under its control to relieve transmission constraint. Excerpt from Chapter 14 of the Version 4 Functional Model Technical Document, below, describes this process:[When a Transmission Operator sees a need for non-voluntary load curtailment to relieve transmission constraints, such as an actual or expected exceedence of an operating limit, it implements load shedding that is under its control, or directs a Distribution Provider to physically implement the curtailment.]Loads that are connected to the transmission facilities and where such loads are not part of the DPs loads can and should be curtailed by the TOP action (to relieve constraints) or by the UFLS relays provided by the TOs (to arrest frequency decline).
Response:		
Xcel Energy	No	We feel 4.3 should be removed.
Response:		

3. **The proposed continent-wide standard requires that Planning Coordinators model the trip settings of any generators that trip at or above 58.0 Hz (Requirement R8) when verifying through dynamic simulation that the UFLS program design is adequate to meet the continent-wide performance characteristics specified in Requirement R6.**

   Do you agree with this approach to ensure that effectiveness of the UFLS program is not jeopardized by units that trip at or above the minimum frequency (58.0 Hz) at which the UFLS program may arrest frequency decline?

Summary Consideration:

Most commenters agree with modeling the trip setting of any generators that trip above 58.0 Hz per R7.

A few commenters want to *reduce* the possible number of units modeled:

1) only include units set up to trip within the first 30 seconds

2) only include units which are set to trip before any UFLS relays for that region

A few entities want to *increase* the possible number of units modeled:

1) By including smaller units, however this is being addressed by PRC-024-1, attachment 1

2) By widening the performance envelope with regard to generator trip settings in order to provide for evaluating UFLS program sensitivities to extreme events

There were a couple of comments concerned with modeling inaccuracies (MOD issues?)

One commenter felt that UFLS ride through is set too low. (This is really a PRC-024 issue)

One commenter wants generators that drive the need for compensatory load shedding to contract for that additional load to be shed.

1. **Per R5 of the first draft of PRC-024-~~0~~1, the Planning Coordinators will have information on generator under-frequency trip settings that fall outside the acceptable boundary defined by PRC-024-1, Attachment 1 and may include this in their database. The SDT agrees that the Generator Owner is already required by draft PRC-024-~~0~~1 to supply this information to the Planning Coordinator and has removed this requirement from the draft standard.**

2. **R7 has been modified to ~~more closely~~ follow the generator tripping boundaries proposed in PRC-024-~~0~~1, Attachment 1, for which the 58.0 Hz threshold was originally meant as a proxy. Temporary excursions below the UFLS set points and time delays of a UFLS program could occur ~~due to generator oscillations~~ and the SDT wants to be sure that the assessments do not overlook any generator settings just below or beyond the UFLS relay settings that may still be reached.**

Organization	Yes or No	Question 3 Comments:
TRE UFLS Standard Drafting Team	Yes	It would appear to be essential that the Planning Coordinators data base include trip settings and time delay to tripping for resources that trip above the 58.0 Hz point. The effective simulation and design of a regional UFLS plan must definitively show the targeted islanding of the region. By not including the modeling of the trip points and time delays for machines that trip above 58.0, Hz, the Planning Coordinator cannot ensure the simulation and plan for effective and survivable islands that can be forecasted to exist post separation.The time criteria in R6.2, particularly the first two cumulative steps, require the effective modeling of machines set to trip above 58.0 Hz.
Response: Thank you for your support. Per R5 of the first draft of PRC-024-~~0~~1, the Planning Coordinators will have information on generator under-frequency trip settings that fall outside the acceptable boundary defined by PRC-024-1, Attachment 1 and may include this in their database.		
Pepco Holdings, Inc – Affiliates	Yes	
Bonneville Power Administration	Yes	
Northeast Power Coordinating Council	Yes	
Southern Company	Yes	The generators must be modeled to reflect the way they perform.
Response: Thank you for your support.		
ERCOT ISO	Yes	ERCOT ISO believes it is necessary to consider all automatic tripping schemes or protection schemes when designing an UFLS program to meet the requirements of this standard. However, explicit modeling of generator frequency trip settings

Organization	Yes or No	Question 3 Comments:
		(above 58.0Hz/below 61.8Hz) should only be required when they are relevant to satisfying the performance requirements of the standard (i.e. if generator trips are initiated for excursions lasting less than 30 seconds).
Response: ~~**Thank you for your support.**~~ ~~**[Note to SDT: since we cannot reference PRC-024-01 or other R's, in R7.1 and 7.2 should we spell out the specific values in R6.2 and R6.3?]**~~ **The standard has been modified to address your comment by including curves above and below which generator underfrequency and overfrequency protection respectively must be modeled. These curves reflect the frequency-time relationship associated with the performance characteristics and are based on the proposed curves in PRC-024-1.**		
Electric Market Policy	Yes	
Midwest ISO Stakeholders Standards Collaborators	Yes	Generation owners certainly have the right to set relays to protect their equipment from damage and are actually speeding restoration by doing so. Any units that will trip before frequency triggers UFLS relays should certainly be considered in the dynamic simulations.
Response: Thank you for your support.		
SERC UFLS Standards Drafting Team	Yes	he generators must be modeled to reflect the way they perform.
Response: Thank you for your support.		
FRCC Standards & Operations Departments	Yes	
Florida Municipal Power Agency and Select Members	Yes	
MRO NERC Standards Review Subcommittee	No	[This question actually applies to Requirement R7, not R8.]We agree that PCs should model the trip settings of any generators that may be tripped during the simulated operation of the UFLS program. However, the applicable generator trip settings may vary depending on the set points and time delays of the underfrequency relays of the UFLS program for a given island. We suggest that R7.1 be reworded to "that trip at or above the minimum frequency set points and time delays of the applicable island's UFLS program". This approach gives consideration to the time delay aspect and allows the frequency limit to be higher (or lower), if it is permitted by the applicable island's UFLS program.We suggest similar

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 3 Comments:</th></tr>
<tr><td></td><td></td><td>rewording for R7.2, "that trip at or above the maximum frequency set points and time delays of the applicable island's UFLS program".On a related matter, the existing Requirement R7 states "conduct a UFLS assessment . . . through dynamic simulations". Therefore, we suggest that the following rewording for R7, "shall conduct a UFLS assessment . . . that determines whether the UFLS program design meets . . . R6. The assessment shall include: " This would allow other analytical methods, such as the Equivalent Inertia Analysis, to be used to perform an appropriate UFLS assessment. The Equivalent Inertia method can also be used to check for proper coordination between the underfrequecy relay settings and the generator trip settings. R7.1 "Analysis of the trip settings of any generators that . . ."R7.2 "Analysis of the trip settings of any generators that . . ." R7.3 "Analysis of any automatic load restoration that . . ."See response to comment 8 regarding the 58 Hz limit.</td></tr>
<tr><td colspan="3">**Response: The SDT apologizes for the incorrect reference to R8. Temporary excursions below the UFLS program set points and time delays ~~of a UFLS program~~ could occur ~~due to generator oscillations~~ and the SDT wants to be sure that the assessments do not overlook any generator settings just below or beyond the UFLS relay settings that may still be reached. Nothing in the standard precludes the use of Equivalent Inertia Analysis in the UFLS design process, but the SDT believes that dynamic simulations are the most dependable means of assessing compliance to the performance characteristics in R6. Equivalent inertia analysis would not include the effects of island initiating disturbances on localized frequency and voltage, inter-machine oscillations, or the particular response of individual unit governors.**</td></tr>
<tr><td>Kansas City Power & Light</td><td>No</td><td>This question is actually referring to requirement R6. What is the engineering basis for 58Hz? The frequency threshold should be based on the prevention of damage to generating equipment, operating equipment, customer loads, etc. Regardless of frequency threshold, all generator protection settings that involve frequency and voltage should be modeled in the simulation studies for UFLS programs.</td></tr>
<tr><td colspan="3">**Response: The SDT apologizes for the incorrect reference to R8. The intent of R6 is to establish UFLS program requirements that coordinate with the acceptable generator tripping boundary defined by PRC-024-1, Attachment 1, and the intent of R7 is to include generator trip settings that fall outside the acceptable boundary defined by R6~~PRC-024-1, Attachment 1~~. R6 has been modified to specify a continuous curve rather than discrete points and R7 has been modified to ~~clarify this intent~~ include the frequency-time relationship by referring to the curve defined in R6~~without referencing that standard~~. ~~[Note to SDT: if agreed, this would be the same modification that satisfies ERCOT ISO comment above]~~ The SDT disagrees that it is necessary to require that protection settings involving voltage need to be modeled in UFLS assessments though that may be advisable when simulating islanding scenarios resulting from severe disturbances.**</td></tr>
<tr><td>IRC Standards Review Committee</td><td>Yes</td><td>We agree but we think you meant R7, not R8. And assuming that the expected loss of generation (for generators tripping at or above 58.0 Hz) is to be compensated by selecting an additional, equivalent amount of load in the UFLS program, the additional load reduction would also need to be simulated.</td></tr>
<tr><td colspan="3">**Response: Thank you for your support. The SDT apologizes for the incorrect reference to R8. The SDT agrees that any extra load shedding necessary for the UFLS program to comply with the performance characteristics in R6 would need to be simulated.**</td></tr>
</table>

Organization	Yes or No	Question 3 Comments:
Cowlitz County PUD	Yes	This seems fair to me. There is no mandate not to allow trip settings above 58 Hz, but there must be very good reasons for such settings, and that such settings will not require greater than necessary load shedding efforts to stabilize the BPS. DPs and LSEs are sensitive to reliable service to their customers. Unnecessary load shedding would add insult to injury.
Response: Thank you for your support. Per R5 and R6 of the first draft of PRC-024-~~0~~1, Generator Owners will need to document, subject to peer review, any generator under-frequency trip settings that fall outside the acceptable boundary defined by PRC-024-1, Attachment 1.		
Edward C. Stein		
Colmac Clarion	No	Some U/F setpoints currently in use above 58.0 Hz were mandated by Generator OEM vice Transmission Operator. All U/F setpoint 'mandates' should be made not to violate design setpoints for specific generators OEM requirements when conducting analysis of setpoints.
Response: The proposed standard does not preclude settings above 58.0 Hz; it only requires such settings be modeled by the Planning Coordinators in their UFLS assessments. Please refer to Project 2007-09 and PRC-024-~~0~~1 for requirements on generator under-frequency settings.		
City of Bedford	Yes	
Alabama Municipal Electric Authority	Yes	
US Army Corps of Engineers	No	Without actually testing the UFLS, how do you know that the simulation testing adequately represents real world events? There needs to be more concrete assurance or testing of the generation side to show that the unis will not trip off. I realize that this assurance should be covered under the MOD Reliability Standards, but I don't think it has been completely addressed.
Response: There is always a question about how well simulation studies represent the real world. Model validation and event replication studies over several decades have increased industry confidence that simulation studies can, in principle, reasonably represent the dynamic behavior of real world power systems. As with any study, assumptions need to be carefully reviewed and validated. We still need to discuss Bob Snow's comment regarding requirements presently in PRC-009. If we include a requirement for model validation following actual disturbances, then we can include a reference to the new requirement in this response. Causes other than frequency-sensing relays may also trip generation outside the acceptable tripping boundaries being proposed in draft PRC-024-~~0~~1, Attachment 1. Unfortunately, you are right in that this possibility is not being addressed. Since PRC-006-01 is not addressing generator tripping requirements, the SDT recommends that this matter be brought to the attention of the Project 2007-09, Generator Verification SDT responsible for PRC-024-~~0~~1.		

Organization	Yes or No	Question 3 Comments:
NIPSCO	No	The existing trip points with out time delay is 58.2 - To protect against turbine blade damage.I believe any under frequency event that allows the frequency to get to 58 HZ is to late/ and to slow.
Response: The SDT disagrees. While it is true that ECAR Document 3 listed 58.2 Hz as the point to expect immediate generator tripping, according to major generator manufacturer's documents, generators can tolerate frequency excursions for limited time below this level. Please refer to Project 2007-09 and PRC-024-~~0~~1 for further information.		
Public Service Electric and Gas Company	No	No, however, while the effort to determine if the UFLS program is effective if generators trip at or above a minimum frequency, we are not sure that any simulations are accurate enough to validate this. Every event is different, but if it can be accurately modeled, then it is a good approach.
Response: There is always a question about how well simulation studies represent the real world. Model validation and event replication studies over several decades have increased industry confidence that simulation studies can, in principle, reasonably represent the dynamic behavior of real world power systems. As with any study, assumptions need to be carefully reviewed and validated.		
Central Lincoln	Yes	
SPP System Protection and Control Working Group	No	What is the basis for 58.0 Hz? If the region's lowest UFLS setting is designed for 58.7 Hz, is 58.0 Hz requirement critical from the Regional UFLS program point of view?
Response: The SDT chose 58.0 Hz as the minimum acceptable frequency to observe for purposes of designing a regional UFLS program. This value also coordinates with the under-frequency generator trip curve in PRC-024-~~0~~1 currently under draft. If a region's lowest UFLS stage is 58.7 Hz, then 58.0 Hz may not be ~~is probably not~~ critical. However, it is possible that temporary excursions below the UFLS program set points and time delays could occur and the SDT wants to be sure that the assessments do not overlook any generator settings just below or beyond the UFLS relay settings that may still be reached.		
Long island power Authority	Yes	
Exelon	Yes	
ReliabilityFirst Corporation	Yes	

Organization	Yes or No	Question 3 Comments:
Arkansas Electric Cooperative Corporation	Yes	
System Protection & Control	Yes	
Duke Energy		
ReliabilityFirst	Yes	
Illinois Municipal Electric Agency		
Hydro-Québec TransEnergie (HQT)	Yes	See also our answer to Q8 in regards to the minimum frequency treshold.
Response: Thank you for your support.		
AEP	Yes	Please note that the reference to R8 in the question appears to an error.
Response: Thank you for your support. The SDT apologizes for the incorrect reference to R8.		
Ontario Power Generation	Yes	
We Energies	Yes	
PacifiCorp	Yes	
NextEra Energy Resources, LLC	Yes	
American Transmission	No	[This question actually applies to Requirement R7, not R8.]We agree that PCs should model the trip settings of any generators that may be trip during the simulated operation of the UFLS program. The applicable generator trip settings will

Organization	Yes or No	Question 3 Comments:
Company		depend on the set points and time delays of the underfrequency relays in the UFLS program. We suggest that R7.1 be reworded to "that trip at or above the minimum frequency set points and time delays of the applicable island's UFLS program". This approach gives consideration to the time delay aspect and allows the frequency limit to be higher (or lower), if it is permitted by the applicable island's UFLS program.We suggest similar rewording for R7.2, "that trip at or above the maximum frequency set points and time delays of the applicable island's UFLS program".On a related matter, the root Requirement R7 states "conduct a UFLS assessment . . . through dynamic simulations". However, other analytical methods, such as Equivalent Inertia Anaysis, can also be used to perform an appropriate UFLS assessment and may check for proper coordination between the underfrequecy relay settings and the generator trip settings. Therefore, we suggest that the following rewording for R7, "shall conduct a UFLS assessment . . . that determines whether the UFLS program design meets . . . R6. The assessment shall inlcude:"R7.1 "Analysis of the trip settings of any generators that . . ."R7.2 "Analysis of the trip settings of any generators that . . ." R7.3 "Analysis of any automatic load restoration that . . ."See the response to Question 8 for comment on the 58.0 Hz and 61.8 Hz limits.
Response: The SDT apologizes for the incorrect reference to R8. Temporary excursions below the UFLS program set points and time delays ~~of a UFLS program~~ could occur ~~due to generator oscillations~~ and the SDT wants to be sure that the assessments do not overlook any generator settings just below or beyond the UFLS relay settings that may still be reached. Nothing in the standard precludes the use of Equivalent Inertia Analysis in the UFLS design process, but the SDT believes that dynamic simulations are the most dependable means of assessing compliance to the performance characteristics in R6. Equivalent inertia analysis would not include the effects of island initiating disturbances on localized frequency and voltage, inter-machine oscillations, or the particular response of individual unit governors.		
Luminant Power	Yes	Luminant agrees with the UFLS SDT that the Planning Coordinators should model the generators that would trip at or above 58.0 Hz, as required by R7. However, Requirement R8 of PRC-006 requires the Planning Coordinator to maintain a database of relay information only from Transmission Owners and Distribution Providers. The Planning Coordinator database in Requirement R8 should also include relay information from Generator Owners. The UFLS SDT does not need to include a requirement in PRC-006 for Generator Owners to provide the information, as the draft NERC Standard PRC-024 requires Generator Owners to provide frequency and voltage relay setting information to the Planning Coordinator.
Response: Thank you for your support. Per R5 of the first draft of PRC-024-~~0~~1, the Planning Coordinators will have information on generator under-frequency trip settings that fall outside the acceptable boundary defined by PRC-024-1, Attachment 1 and may include this in their database. The SDT agrees that the Generator Owner is already required by draft PRC-024-~~0~~1 to supply this information to the Planning Coordinator and has removed this requirement from the draft standard.		
Ameren	Yes	Yes, such generators should have their trip settings modeled to determine the additional load that must be shed because they do not meet performance characteristics. The cost to include this additional load shed should be allocated to these generators.

Organization	Yes or No	Question 3 Comments:
Response: Thank you for your support. Cost allocation is outside the scope of reliability standards.		
FirstEnergy Corp	No	The Planning Coordinator should be required to model somewhat below the 58.0 Hz level, we suggest down to 57.5 Hz, so that a sensitivity analysis is performed evaluating the severity of frequency disturbance that is not fully arrested at or above the 58 Hz level. This information could be used to assess if additional load dropping may be needed for more severe frequency events.
Response: ~~[Note to SDT: I think I will have to agree with this, but maybe we only need to go as far as 57.8 Hz which is where PRC-024 curve begins.]~~ The standard has been modified to address your comment~~, though the SDT believes it is only necessary to go as far as 57.8 Hz, which is where the draft PRC-024-01 curve begins~~. The SDT has included curves above and below which generator underfrequency and overfrequency protection respectively must be modeled. These curves reflect the frequency-time relationship associated with the performance characteristics and are based on the proposed curves in PRC-024-1. As such, the minimum trip threshold that must be modeled is 57.8 Hz rather than 57.5 Hz, which the SDT believes provides adequate margin.		
CenterPoint Energy		
Independent Electricity System Operator	Yes	We agree but I think you meant R7, not R8. And assuming that the expected loss of generation (for generators tripping at or above 58.0 Hz) is to be compensated by selecting an additional, equivalent amount of load in the UFLS program, the additional load reduction would also need to be simulated. If this requirement is to be added, depending on how this is to be complied with the Applicability Section may need to be expanded.
Response: Thank you for your support. The SDT apologizes for the incorrect reference to R8. The SDT agrees that any extra load shedding necessary for the UFLS program to comply with the performance characteristics in R6 would need to be simulated. The applicability section does not need to be expanded because Planning Coordinators would still be the applicable entities to demonstrate compliance with R6 in R7.		
Xcel Energy	Yes	The dynamic simulation would need to include any small generators (<20MVA or <75MVA aggregate) that are not required to register, but together, could have a material impact on the BES. Additionally, it would need to be clear who is responsible for ensuring those material impacts are included in models/simulations.
Response: Thank you for your support. The SDT agrees. The Planning Coordinators are the responsible entity for ensuring that material impacts are included. The applicability of smaller generators to report under-frequency trip settings outside the acceptable boundary of PRC-024-~~0~~1, Attachment 1 is being addressed in that standard.		

4. The SDT added a requirement that requires the Planning Coordinators model, in the five year assessments, any automatic load restoration that is designed to assist in stabilizing system frequency (Requirement R9). The team decided to add this requirement as a result of a comment during the first posting. Do you agree that this requirement is necessary for reliability?

Summary Consideration:

Most entities support this requirement.

Some want exceptions to be allowed to be excluded from program design if the automatic load restoration is "insignificant".

Some feel this requirement does not go far enough to include ***ALL*** automatic load restoration schemes which may impact UFLS, not just the ones ***designed*** to impact UFLS.

Some feel that automatic load restoration is generally a bad idea for use with UFLS.

Organization	Yes or No	Question 4 Comments:
TRE UFLS Standard Drafting Team	Yes	The TRE UFLS SDT believes that successful deployment of a UFLS is dependent on two concepts. The first is automatic reaction of the UFLS when frequency triggers its response to dump load. The second is load shall not be brought back until the Reliability Coordinator instructs each entity to do so in whatever order is appropriate for adequate recovery. Therefore modeling of any applicable automatic load restoration should be included in a region's UFLS program.
Response: Thank you for your support.		
Pepco Holdings, Inc - Affiliates	Yes	
Bonneville Power Administration	Yes	It addresses automatic load restoration for frequency over-shoot.
Response: Thank you for your support.		
Northeast Power Coordinating Council	Yes	We believe that any automatic action that impacts recovery and stabilization of frequency must be modeled.

Organization	Yes or No	Question 4 Comments:
Response: Thank you for your support.		
Southern Company	Yes	Yes, but with the ability to specify exceptions. Each regional entity should be required to identify the amount of automatic load restoration in their region that is designed to assist in stabilizing system frequency. If the region determines that this amount is insignificant (e.g. 1%) and will not materially impact the design of the region's UFLS scheme, then they should be allowed to exclude this load from their simulations.
Response: ~~Note to SDT: Should we allow for an exception? Possible change: R7.3. Modeling any automatic load restoration which will restore 1% or more of load included in the island under study.~~ The SDT has revised Requirement R7.3 to require modeling of any automatic load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the UFLS assessment.		
ERCOT ISO	Yes	At this time ERCOT ISO does not know of any automatic load restoration schemes within the ERCOT Interconnection. But as previously stated in question 3, it is necessary to consider all automatic tripping schemes when developing an UFLS program to meet the requirements of this standard, and therefore ERCOT ISO agrees this is necessary.
Response: Thank you for your support.		
Electric Market Policy	Yes	However, Question 4 reference to Requirement R9 should be R7.
Response: The SDT apologizes for the incorrect reference to R9.		
Midwest ISO Stakeholders Standards Collaborators	Yes	Generally, automatic load restoration is a bad idea. It could interfere with restoration. What if too much load is restored and actually causes frequency to decline significantly?
Response: The SDT ~~believes that the purpose of including~~ included modeling of automatic load restoration in UFLS program ~~design is intended~~ assessments to ~~prevent~~ identify any unintended consequences of using automatic load restoration.		
SERC UFLS Standards Drafting Team	Yes	Yes, but with the ability to specify exceptions. Each regional should be required to identify the amount of automatic load restoration in their region that is design to assist in stabilizing system frequency. If the region determines that this amount is insignificant (e.g. 1%) and will not materially impact the design of the region's UFLS scheme, then they should be allowed to excluded this load from their simulations.
Response: ~~Note to SDT: Should we allow for an exception? Possible change: R7.3. Modeling any automatic load restoration which will restore 1% or more of load included in the island under study.~~ The SDT has revised Requirement R7.3 to require modeling of any automatic load restoration that		

Organization	Yes or No	Question 4 Comments:
impacts frequency stabilization and operates within the duration of the simulations run for the UFLS assessment.		
FRCC Standards & Operations Departments	Yes	
Florida Municipal Power Agency and Select Members	Yes	
MRO NERC Standards Review Subcommittee	Yes	This question actually applies to Requirement R7.3, not R9.]We agree that any automatic load restoration that is designed to assist in stabilizing the system frequency should be modeled in the ULFS Program assessment.
Response: The SDT apologizes for the incorrect reference to R9. Thank you for your support.		
Kansas City Power & Light	Yes	
IRC Standards Review Comittee	Yes	We agree with this requirement but believe there should be more specific language on what schemes should be included in the study. There may also be automatic load restoration schemes that have an impact on stabilizing system frequency but was not installed with that intent. The study should also consider the effects of these automatic restoration schemes. Again, we think you meant R7, not R9. We agree. Any pre-determined actions such as tripping of additional load for generator tripping at or above 58.0 Hz as discussed in Q3, above, and automatic restoration of load, etc. should be modeled and assessed via simulations to evaluate frequency performance of potential islands.
Response: ~~Possible change: R7.3. Modeling any automatic load restoration which will restore 1% or more of load included in the island under study.~~ The SDT agrees that all automatic load restoration that may affect frequency stabilization should be modeled regardless of the design intent. The SDT has revised Requirement R7.3 to require modeling of any automatic load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the UFLS assessment. **The SDT apologizes for the incorrect reference to R9.** **Thank you for your support.**		
Cowlitz County PUD	Yes	You meant Requirment R7.3? This seems to be an excellent idea to me. Anything that both stabilizes the BPS and

Organization	Yes or No	Question 4 Comments:
		improves on customer service is a winner.
Response: The SDT apologizes for the incorrect reference to R9. Thank you for your support.		
Edward C. Stein		
Colmac Clarion	Yes	
City of Bedford	Yes	
Alabama Municipal Electric Authority	No	If the automatic load was induced by inductors I would have voted yes because this is part of good planning. I voted "no" because there is no way to determine or predict that "all" of the load for a load restoration activity would be "available" if the automatic load restoration was for user or customer load.
Response: The SDT makes no reference to the origination of the load to be included for automatic restoration in the UFLS program design. Where such automatic load restoration is utilized, ~~This designation must be left to~~ the Planning Coordinators are required to model, in ~~for inclusion in~~ their UFLS program assessments, ~~design~~ the actual scheme as implemented.		
US Army Corps of Engineers	Yes	Modeling automatic load restoration on a 5 year cycle should capture the changes/modifications that the individual Registered Entities have done to their system. Too often the minor tweaks to a system get lost in the cracks and the cumulative modifications do have an impact on system studies.
Response: Thank you for your comments.		
NIPSCO	Yes	
Public Service Electric and Gas Company	No	It would not seem practical to consider automatic load restoration as a method to stabilize a system.
Response: The SDT is not requiring the use of automatic load restoration schemes and acknowledges this may not be a practical method to stabilize some systems. ~~disagrees~~. However, where automatic load restoration schemes are utilized a ~~F~~failure to consider them ~~automatic load restoration schemes included as part~~ in assessments of the UFLS program design may result in unintended consequences during actual UFLS events.		
Central Lincoln	Yes	

Organization	Yes or No	Question 4 Comments:
SPP System Protection and Control Working Group	Yes	We agree with this requirement but believe there should be more specific language on what schemes should be included in the study. There may also be automatic load restoration schemes that have an impact on stabilizing system frequency but was not installed with that intent. The study should also consider the effects of these automatic restoration schemes.
Response: ~~Possible change: R7.3. Modeling any automatic load restoration which will restore 1% or more of load included in the island under study.~~ The SDT agrees that all automatic load restoration that may affect frequency stabilization should be modeled regardless of the design intent. The SDT has revised Requirement R7.3 to require modeling of any automatic load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the UFLS assessment.		
Long island power Authority	Yes	
Exelon	Yes	It should be clear only those restoration systems designed to stabilize system frequency should be included in the standard. Requirement 9 in the proposed standard does not appear to be related to automatic load restoration systems.
Response: The SDT agrees. ~~Thank you for your support OR The SDT disagrees. Possible change: R7.3. Modeling any automatic load restoration which will restore 1% or more of load included in the island under study.~~ The SDT agrees with other commenters who have noted that all automatic load restoration that may affect frequency stabilization should be modeled regardless of the design intent. The SDT has revised Requirement R7.3 to require modeling of any automatic load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the UFLS assessment. **The SDT apologizes for the incorrect reference to R9.**		
ReliabilityFirst Corporation	Yes	
Arkansas Electric Cooperative Corporation	Yes	It stands to reason that any tripping or restoration schemes that are automatic should be modeled and included in the simulations.
Response: Thank you for your support.		
System Protection & Control	Yes	

Organization	Yes or No	Question 4 Comments:
Duke Energy		
ReliabilityFirst	Yes	
Illinois Municipal Electric Agency		
Hydro-Québec TransEnergie (HQT)	Yes	HQT believe that any automatic action that impacts recovery and stabilization of frequency must be modeled.
Response: Thank you for your support.		
AEP	Yes	Please note that we are responding in the context of requirement 7.3, not requirement 9. There appears to be a error in the requirement 9 reference.
Response: The SDT apologizes for the incorrect reference to R9.		
Ontario Power Generation	Yes	
We Energies	Yes	
PacifiCorp	Yes	
NextEra Energy Resources, LLC	Yes	
American Transmission Company	Yes	[This question actually applies to Requirement R7.3, not R9.] We agree that any automatic load restoration that is designed to assist in stabilizing the system frequency should be modeled in the ULFS Program assessment. On the other hand, we suggest that automatic load restoration should be avoided whenever possible.
Response: The SDT apologizes for the incorrect reference to R9. **Thank you for your support.**		

Organization	Yes or No	Question 4 Comments:
Luminant Power	Yes	
Ameren	No	Each region should be required to identify the amount of automatic load restoration in their region that is designed to assist in stabilizing system frequency. If the region determines that this amount is insignificant and will not materially impact the design of the region's UFLS program, then they should be allowed to exclude this load from their simulations.
Response: ~~Note to SDT: Should we allow for an exception? Possible change: R7.3. Modeling any automatic load restoration which will restore 1% or more of load included in the island under study.~~ **The SDT has revised Requirement R7.3 to require modeling of any automatic load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the UFLS assessment.**		
FirstEnergy Corp	Yes	
CenterPoint Energy		
Independent Electricity System Operator	Yes	Again, we think you meant R7, not R9. We agree. Any pre-determined actions such as tripping of additional load for generator tripping at or above 58.0 Hz as discussed in Q3, above, and automatic restoration of load, etc. should be modeled and assessed via simulations to evaluate frequency performance of potential islands.
Response: The SDT apologizes for the incorrect reference to R9. **Thank you for your support.**		
Xcel Energy	Yes	(We assume you meant R7, not R9.)
Response: The SDT apologizes for the incorrect reference to R9.		

5. **The SDT added a requirement in the underfrequency load shedding performance characteristics that requires (in simulations) frequency to not remain below 58.2 Hz for greater than four seconds cumulatively per simulated event (Requirement R6.2). The SDT added this requirement to better coordinate with the Generator Verification Project (PRC-024) tripping curve. Do you agree with this additional requirement?**

Summary Consideration:

Organization	Yes or No	Question 5 Comments:
TRE UFLS Standard Drafting Team	Yes	The TRE UFLS SDT agrees that the UFLS program should coordinate with the performance requirements of the Generation Verification Project (PRC-024-1). The requirement for not remaining below 58.2 Hz for greater than four seconds appears to be within the No Trip Zone area of the Off Normal Frequency Capability Curve in Attachment 1 of PRC-024-1.
Response:		
Pepco Holdings, Inc - Affiliates	Yes	
Bonneville Power Administration	Yes	
Northeast Power Coordinating Council	Yes	We believe it is important to remove this apparent miscoordination between the generator tripping requirements in PRC-024 and the UFLS program performance requirements in PRC-006.
Response:		
Southern Company		We agree this change better coordinates with PRC-024.If coordination with PRC-024 is the ultimate goal, it seems a simple offset would be better. For example, adding 0.1 Hz to the PRC-024 underfrequency requirements would seem more straightforward and provide a more consistent offset (58 Hz at 3 sec and 59.6 Hz at 1800 sec.).
Response:		
ERCOT ISO	Yes	ERCOT ISO agrees that the UFLS program should coordinate with the performance requirements of the Generation Verification Project (PRC-024-1). The requirement for not remaining below 58.2 Hz for greater than four seconds appears

Organization	Yes or No	Question 5 Comments:
		to be within the No Trip Zone area of the Off Normal Frequency Capability Curve in Attachment 1 of PRC-024-1.
Response:		
Electric Market Policy	Yes	
Midwest ISO Stakeholders Standards Collaborators	No	Please provide the technical justification for this performance criterion.We would like to add the statement "Unless generation capability or protection warrants or allows for a lower limit" to the end of the requirement. In the MRO region, this would help Manitoba Hydro and Saskatchewan that need to shed more than 30% of the area load. In these areas, when shedding that much load the frequency would drop below 58.2 Hz for longer than 4 seconds.We understand the SDT wants to ensure load shedding programs achieve quick frequency recovery and minimize underfrequency exposure. However we do not feel this requirement is the right way to go about that. This type of criteria is overly specific and should not be in the NERC standard. The recently developed MRO UFLS program which sheds 30% of system load appears to meet this criteria, but the Canadian portions of MRO which have higher load shedding requirements are unlikely meet this criteria. Aggressive load shedding programs in general will probably not satisfy this requirement. Frequency recovery, overall load shedding performance, and coordination with generation protection, should all be evaluated at the regional level by those who do the technical analysis of regional load shedding programs. In addition to study work, a lot of common sense needs to be applied. Several things need to be discussed to clarify our position.
Response:		
SERC UFLS Standards Drafting Team		We agree this change better coordinates with PRC-024.If coordination with PRC-024 is the ultimate goal, it seems a simple offset would be better. For example, adding 0.1 Hz to the PRC-024 underfrequency requirements would seem more straightforward and provide a more consistent offset (58 Hz at 3 sec and 59.6 Hz at 1800 sec.)
Response:		
FRCC Standards & Operations Departments	Yes	
Florida Municipal Power Agency and Select Members	Yes	
MRO NERC Standards	No	Please provide the technical justification for this performance criteria.We suggest the addition of the statement "Unless

Organization	Yes or No	Question 5 Comments:
Review Subcommittee		generation capability or protection warrants or allows for a lower limit" to the end of Requirement R6.2. In the MRO region, this qualification would help Manitoba Hydro and Saskatchewan that need to shed more than 30% of the area load to achieve reasonable frequency recovery in these islands. In these areas, the shedding of a higher percentage of load may allow the frequency to drop below 58.2 Hz for longer than 4 seconds, but the subsequent impacts on the hydro generator in these islands are acceptable.On a related note, we suggest the addition of the statement "Unless generation capability or protection warrants or allows for a higher limit" to the end of Requirement R6.3, if the impacts of island equipment are acceptable.
Response:		
Kansas City Power & Light	No	Do not have a problem with a frequency threshold or duration, however, 58.2Hz and 4 seconds sounds arbitrary. UFLS systems have been in place for years and would be very difficult and expensive to modify to meet the criteria stated here. To justify any need to go to that expense, it is important to establish the engineering basis for this criteria. What is the engineering basis for the 58.2Hz and 4 seconds?
Response:		
IRC Standards Review Comittee	Yes	We do not have a concern with this requirement if the 0.2 Hz above 58.0 Hz is intended as a margin/buffer to ensure generators do not trip pre-maturely.
Response:		
Cowlitz County PUD	Yes	
Edward C. Stein		
Colmac Clarion	Yes	Agree that it is a reasonable setpoint for consistent evaluation/simulation; may not be reasonable as a 'limit' after evaluation is complete.
Response:		
City of Bedford	Yes	
Alabama Municipal Electric Authority	Yes	The SDT should consider changing the four seconds to six seconds because of the data scanning requirements of other generator functions such as automatic generation control.

Organization	Yes or No	Question 5 Comments:
Response:		
US Army Corps of Engineers	Yes	
NIPSCO	No	4 seconds is to long.
Response:		
Public Service Electric and Gas Company		
Central Lincoln	Yes	
SPP System Protection and Control Working Group	Yes	
Long island power Authority	Yes	
Exelon	No	This should be left up to the regions. Load trip set points are left up to the Regions and thus so should generating unit settings. Unit coordination requirements should be part of the PRC standards (PRC-001 and PRC-024). This requirement leaves the responsibilities of attaining this goal ambiguous. It would not be appropriate to base compliance on an entity performing a study on the study outcome.
Response:		
ReliabilityFirst Corporation	Yes	
Arkansas Electric Cooperative Corporation		

Organization	Yes or No	Question 5 Comments:
System Protection & Control	Yes	
Duke Energy	No	We agree this change better coordinates with PRC-024.If coordination with PRC-024 is the ultimate goal, it seems a simple offset would be better. For example, adding 0.1 Hz to the PRC-024 underfrequency requirements would seem more straightforward and provide a more consistent offset (58 Hz at 3 sec and 59.6 Hz at 1800 sec.) The stair step created by the proposed method greatly reduces the area available above the PRC-024 limit.[SERC UVLS team see chart below]Even with the added requirement, the UFLS curve still does not coordinate with the PRC 024 curve at 59.5 Hz. If the 59.3 Hz proposed by PRC-006 is maintained, then it seems PRC-024 should be approximately 0.1 Hz lower, 59.2 Hz. Otherwise, the upper limit for PRC-006 must be increased to coordinate with the PRC-024 curve (e.g. increase by 0.3 Hz to 59.6 Hz). Similarly, the upper requirement does not coordinate with PRC-024 out in time.
Response:		
ReliabilityFirst	Yes	
Illinois Municipal Electric Agency		
Hydro-Québec TransEnergie (HQT)	Yes	HQT believe it is important to remove this apparent miscoordination between the generator tripping requirements in PRC-024 and the UFLS program performance requirements in PRC-006.See also our answer to Q8 in regards to frequency treshold.
Response:		
AEP	Yes	
Ontario Power Generation	Yes	
We Energies	Yes	
PacifiCorp	Yes	Coordination with PRC-024 is very important. PacifiCorp supports this change.
Response:		

Organization	Yes or No	Question 5 Comments:
NextEra Energy Resources, LLC	Yes	
American Transmission Company	No	Please provide the industry with the technical justification for this performance criteria.We would like to add the statement "Unless generation capability or protection warrants or allows for a lower limit" to the end of Requirement R6.2 and R6.3. In the MRO region, this qualification would help Manitoba Hydro and Saskatchewan that need to shed more than 30% of the area load to achieve reasonable frequency recovery in these islands. In these areas, the shedding this quantity of load may allow the frequency to drop below 58.2 Hz for longer than 4 seconds, but the subsequent impacts on the hydro generators in these islands are acceptable.
Response:		
Luminant Power	Yes	
Ameren	Yes	It is a step in the right direction but additional modifications to the performance characteristics are needed to coordinate effectively with PRC-024. When viewing the frequency and time limits in PRC-024 simultaneously with this draft standard in a graphical manner, there are regions of frequency and time duration for which it is permitted for the generators to operate, but for which it is not permitted for the system as a whole to operate.
Response:		
FirstEnergy Corp	No	The requirement does not exactly match those in PRC-024-1 (Attachment 1) on generator frequency characteristics. In fact, reliability would be better served if the frequency requirements for generators was in PRC-006 rather than PRC-024. For UFLS to be effective, it is a fundamental concept that generation stay connected long enough for load shedding to fully occur. By separating these requirements into different standards, it discounts the need to balance load and generation in a stressed system. PRC-024 allows GO's to be granted exceptions to meeting a fairly generous frequency characteristic but there are no assurances that an equivalent load is shed to balance these exceptions.
Response:		
CenterPoint Energy		
Independent Electricity System Operator	Yes	We do not have a concern with this requirement if the 0.2 Hz above 58.0 Hz is intended as a margin/buffer to ensure generators do not trip pre-maturely. However, we do have a concern with R6.3.During the 2003 blackout, the overfrequency limits in R6.3 were violated without any reported adverse effects on the BES. Why are the overfrequency limits needed?

Organization	Yes or No	Question 5 Comments:
		If they are not needed to protection equipment, then they should be removed.
Response:		
Xcel Energy	Yes	We support the philosophy that load shedding should occur prior to generation tripping. We feel it is important to keep these two projects coordinated.
Response:		

6. **In the first posting, the Characteristics of UFLS Regional Reliability Standards required that UFLS programs be designed to limit the potential for overexcitation (V/Hz) of power system equipment at all Bulk Electric System buses. Based on industry comments, the SDT has revised this requirement in the proposed continent-wide standard to apply only at generator buses and generator step-up transformer high-side buses associated with individual generating units greater than 20 MVA (gross nameplate rating) and generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) that are directly connected to the BES. The SDT believes this change better addresses the need to have UFLS programs designed to coordinate with protection that may trip generators during an underfrequency event. Do you agree with this change?**

Summary Consideration:

Organization	Yes or No	Question 6 Comments:
TRE UFLS Standard Drafting Team	Yes	The TRE UFLS SDT believes this change creates a clear definition for equipment at generator buses and step-up transformer high-side buses for which the standard applies. However, the NERC UFLS SDT may want to consider adapting the definition of applicable generating units to conform to NERC's Compliance Registry Criteria (NERC Statement Compliance Registry Criteria Rev 5.0 (October 16, 2008) www.nerc.com/files/Statement_Compliance_Registry_Criteria-V5-0[1].pdf for Generator Owner/Operator:- Individual generating unit greater than 20 MVA (gross nameplate rating) and is directly connected to the bulk power system;- Generating plant/facility greater than 75 MVA (gross aggregate nameplate rating) or when the entity has responsibility for any facility consisting of one or more units that are connected to the bulk power system at a common bus with total generation above 75 MVA gross nameplate rating.This change would bring consistency to the definition of applicable generating units and would ensure that there is no confusion for wind farms and other generating plants/facilities.
Response:		
Pepco Holdings, Inc - Affiliates	Yes	
Bonneville Power Administration	Yes	
Northeast Power Coordinating Council	No	We agree with the intent of the change to focus the concern on buses where V/Hz protection may trip generators rather than broadly applying to all BES buses. However, reliability of underfrequency load shedding (UFLS) programs is dependent on assurance that the UFLS program will shed load prior to generation tripping in islanded conditions. The

Organization	Yes or No	Question 6 Comments:
		frequency response to generator tripping is primarily a function of the amount of generation tripped and is substantially independent of the location of the generator interconnection. Therefore, the standard should not specify a threshold on interconnection voltage or generating unit/plant nameplate MVA. We recommend that R6.4 apply to all generator buses and generator step-up (GSU) high-side buses similar to R7.1 and R7.2 applying to all generators that trip above 58.0 Hz or below 61.8 Hz.
Response:		
Southern Company	Yes	No additional comment.
ERCOT ISO	Yes	ERCOT ISO agrees with the change.
Response:		
Electric Market Policy	Yes	
Midwest ISO Stakeholders Standards Collaborators	No	Please provide the technical justification for this performance criteria. We are presently unaware of any UFLS event where V/Hz tripped a unit.This requirement should not be included with this standard because it cannot be properly simulated because the voltage regulator V/Hz controls are not presently included in generator exciter/voltage regulator models that are used for stability simulation.The volts per hertz language does not belong in this load shedding document. Voltage regulators automatically reduce voltage according to volts per hertz when in automatic mode. Industry recommendations/standards (IEEE C37.102 or IEEE C37.106, ANSI C50.13-1989, IEEE C57.12.00-2000) already exist to address volts/Hz. If voltage regulators fail, or are in manual control, then there is additional volts/Hz relaying to trip generation if needed. We believe the volts per hertz issues are already taken care of outside of this UFLS standards document. During an under frequency event, generators should be working to pull voltages down anyway.Please see response to question 8 regarding overvoltages related to tripping load without tripping capacitors.
Response:		
SERC UFLS Standards Drafting Team	Yes	
FRCC Standards & Operations Departments	Yes	

Organization	Yes or No	Question 6 Comments:
Florida Municipal Power Agency and Select Members	Yes	
MRO NERC Standards Review Subcommittee	No	Please provide the technical justification for this performance criteria. We are unaware of any UFLS event where V/Hz protection tripped a generator unit.This requirement should not be included with this standard because it cannot be properly simulated. The voltage regulator V/Hz controls are not presently included in generator exciter/voltage regulator models of the present power system modeling programs that are used for dynamic power system simulation.The volts per hertz language does not belong in this load shedding document. Voltage regulators automatically reduce voltage according to volts per hertz when in automatic mode. Industry recommendations/standards (IEEE C37.102 or IEEE C37.106, ANSI C50.13-1989, IEEE C57.12.00-2000) already exist to address volts/Hz. If voltage regulators fail, or are in manual control, then there is additional volts/Hz relaying to trip generation if needed. We believe the volts per hertz issues are already taken care of outside of this UFLS standards document.
Response:		
Kansas City Power & Light	No	Do not agree with requirement R6.4 regarding the criteria for ensuring control voltage at the generator does not exceed 1.18 V/Hz for a duration longer than 2 seconds. The operating boundaries and control schemes at the generators are in place for the protection and reliable operation of the generator and should be modeled as they are and UFLS design should be modeled around the generator in the attempt to maintain generator connection to the grid.
Response:		
IRC Standards Review Comittee	No	We do not see the need to specify these criteria in the standard. Applicable requirements should be assigned to all generators that meet the compliance registry criteria.
Response:		
Cowlitz County PUD	Yes	
Edward C. Stein		
Colmac Clarion	Yes	Be aware that some small generators (>20 MVA but <75 MVA with 'extended' tielines may have difficulty meeting this requirement with some 'older' voltage regulators and stepup transformer arrangements.

Organization	Yes or No	Question 6 Comments:
Response:		
City of Bedford	Yes	
Alabama Municipal Electric Authority	Yes	The SDT should consider the potential discrepancy with the generator side and their desire to include automatic load reduction. I assume automati load reduction would not take place at a generator bus.
Response:		
US Army Corps of Engineers	Yes	
NIPSCO	No	Since much of the future generation seems to be wind power- they should be included
Response:		
Public Service Electric and Gas Company		
Central Lincoln	Yes	
SPP System Protection and Control Working Group	Yes	Please confirm whether this requirement is applicable for generating stations/ plants connected to BES above 100 kV.
Response:		
Long island power Authority	Yes	
Exelon	No	Don't agree with going into the generator over excitation equipment. This is an issue that is regional in nature and should be addressed at that level.
Response:		

Organization	Yes or No	Question 6 Comments:
ReliabilityFirst Corporation	Yes	
Arkansas Electric Cooperative Corporation		
System Protection & Control	Yes	
Duke Energy		
ReliabilityFirst	Yes	
Illinois Municipal Electric Agency		
Hydro-Québec TransEnergie (HQT)	No	HQT agree with the intent of the change to focus the concern on buses where V/Hz protection may trip generators rather than broadly applying to all BES buses. However, reliability of underfrequency load shedding (UFLS) programs is dependent on assurance that the UFLS program will shed load prior to generation tripping in islanded conditions. The frequency response to generator tripping is primarily a function of the amount of generation tripped and is substantially independent of the location of the generator interconnection. Therefore, the standard should not specify a threshold on interconnection voltage or generating unit/plant nameplate MVA. We recommend that R6.4 apply to all generator buses and generator step-up (GSU) high-side buses similar to R7.1 and R7.2 applying to all generators that trip at particular frequency tresholds. See also our answer to Q8 in regards to frequency treshold.
Response:		
AEP	Yes	
Ontario Power Generation	Yes	
We Energies	Yes	

Organization	Yes or No	Question 6 Comments:
PacifiCorp	Yes	PacifiCorp concurs with the decision of the SDT drafting team. V/Hz capability is generally associated with generating plants, not all buses within a system.
Response:		
NextEra Energy Resources, LLC		No comment.
American Transmission Company	No	Please provide the industry with the technical justification for this performance criteria. We are presently unaware of any UFLS event where V/Hz tripped a generator unit.This requirement should not be included with this standard because it cannot be properly simulated. The voltage regulator V/Hz controls are not presently included in generator exciter/voltage regulator models of the present power system modeling programs that are used for dynamic power system simulation.The volts per hertz language does not belong in this load shedding document. Voltage regulators automatically reduce voltage according to volts per hertz when in automatic mode. Industry recommendations/standards (IEEE C37.102 or IEEE C37.106, ANSI C50.13-1989, IEEE C57.12.00-2000)) already exist to address volts/Hz. If voltage regulators fail, or are in manual control, then there is additional volts/Hz relaying to trip generation if needed. We believe the volts per hertz issues are already taken care of outside of this UFLS standards document.
Response:		
Luminant Power	Yes	Luminant agrees with the direction of the UFLS SDT. Luminant further requests that the drafting team modify Requirement R6.4 to clarify that the per unit V/Hz limits modeled are 1.18 and 1.10 of Nominal transmission system voltage.
Response:		
Ameren	Yes	It is an improvement over the previous draft. However, there are still questions as to whether this requirement is needed. Please provide the technical justification for this performance criteria. We are presently unaware of any UFLS event where V/Hz tripped a unit. This requirement should not be included with this standard because it cannot be properly simulated because the voltage regulator V/Hz controls are not presently included in generator exciter/voltage regulator models that are used for stability simulation.
Response:		
FirstEnergy Corp	No	The requirement has been devised to protect generators and step-up transformers from over-excitation based on traditional protection guidelines. However, other elements in the BES can also become over-excited. Dynamic simulations look at many quantities such as voltage and frequency but Volts/Frequency is not a common output that is reviewed. It is

Organization	Yes or No	Question 6 Comments:
		suggested that it would be better to require that bulk capacitors be tripped if system voltage exceeds equipment limits.
Response:		
CenterPoint Energy		
Independent Electricity System Operator	No	The 20 MVA/unit and 75 MVA per generating plant/facility thresholds are the same as those presented in PRC-024, on which we expressed a disagreement. In an islanded situation, each generator's status is critical to ensuring frequency decline is successfully arrested based on the assumption that all on-line generators would not trip within specific frequency bounds unless prior approval has been sought and granted to allow tripping. Not limiting the potential for overexcitation (V/Hz) at the smaller generators/plants exposes the island to a great uncertainty on the amount of generation that can be relied upon to arrest frequency excursion.
Response:		
Xcel Energy	No	No. Criteria in 6.4.1 and 6.4.2 looks like it is only measuring generators that are required to be registered. Yet, with increasing penetration of small generators (<20MVA, <75 MVA aggregate), we feel the scope is not large enough to consider a material impact on the BES by an aggregate of these small generators. (Same concern carries into R7)
Response:		

7. **If you are aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement, or agreement please identify the conflict in the comments section.**

Summary Consideration:

Organization	Question 7 Comments:
TRE UFLS Standard Drafting Team	At this time, the TRE UFLS SDT does not believe this proposed standard conflicts with any regulatory function, rule, order, tariff, rate schedule, legislative requirement, or other applicable standard of which the team members are aware.
Response:	
Pepco Holdings, Inc - Affiliates	
Bonneville Power Administration	
Northeast Power Coordinating Council	
Southern Company	No Comments for Question #7.
ERCOT ISO	No comment
Electric Market Policy	None
Midwest ISO Stakeholders Standards Collaborators	
SERC UFLS Standards Drafting Team	
FRCC Standards & Operations Departments	

Organization	Question 7 Comments:
Florida Municipal Power Agency and Select Members	
MRO NERC Standards Review Subcommittee	
Kansas City Power & Light	Not aware of any conflicts.
IRC Standards Review Comittee	None
Cowlitz County PUD	
Edward C. Stein	
Colmac Clarion	Requirement differ from some current contract requirements that were 'inclusive' of existing tieline standards when written.
Response:	
City of Bedford	
Alabama Municipal Electric Authority	The SDT should re-look at the timing requirements (4 seconds)in this standard and the timing requirements (such as 6 seconds in the AGC requirement) of other standards.
Response:	
US Army Corps of Engineers	
NIPSCO	
Public Service Electric and Gas Company	Not aware of any conflicts.
Central Lincoln	

Organization	Question 7 Comments:
SPP System Protection and Control Working Group	None at this time.
Long island power Authority	
Exelon	Not aware of any conflicts at this time.
ReliabilityFirst Corporation	
Arkansas Electric Cooperative Corporation	
System Protection & Control	
Duke Energy	
ReliabilityFirst	
Illinois Municipal Electric Agency	
Hydro-Québec TransEnergie (HQT)	
AEP	
Ontario Power Generation	
We Energies	We are not aware of any conflicts.
PacifiCorp	No comment
NextEra Energy Resources, LLC	No comment.
American Transmission Company	

Organization	Question 7 Comments:
Luminant Power	None
Ameren	No
FirstEnergy Corp	We are not aware of any conflicts.
CenterPoint Energy	
Independent Electricity System Operator	None
Xcel Energy	At this time, the TRE UFLS SDT does not believe this proposed standard conflicts with any regulatory function, rule, order, tariff, rate schedule, legislative requirement, or other applicable standard of which the team members are aware.
Response:	

8. Please provide any other comments (that you have not already provided in response to the questions above) that you have on the draft standard PRC-006-1.

Summary Consideration:

Organization	Question 8 Comments:
TRE UFLS Standard Drafting Team	The TRE UFLS SDT appreciates the opportunity to provide these comments and commends the NERC UFLS SDT for its efforts.
Response: Thank you for your support.	
Pepco Holdings, Inc - Affiliates	
Bonneville Power Administration	The Applicability should be Planning Coordinators and Balancing Authorities. BPA suggests that everywhere it currently states Planning Coordinator that it be changed to ?Planning Coordinator/Balancing Authority?. R3. - This needs to say why they are selecting portions of the BES that may form islands. The reason would be "that may form islands to simulate frequency performance and design the UFLS schemes." **The reason is given in R5.** R5. Second bullet - This should include both "relay scheme or special protection system." **The SDT agrees.** Related to R9. - Each Generator Owner also needs to provide data for their under frequency trip settings, if they are within the band specified, 58.0 Hz to 61.8 Hz, since they also need to be considered in the simulations. **Per R5 of the first draft of PRC-024-~~0~~1, the Planning Coordinators will have information on generator under-frequency trip settings that fall outside the acceptable boundary defined by PRC-024-1, Attachment 1 and may include this in their database.**
Response:	

Organization	Question 8 Comments:
Northeast Power Coordinating Council	NPCC has previously commented that the objective to control frequency overshoot cannot be met through UFLS program design alone in the absence of adequate generating unit governing response. Our immediate concern has been addressed by increasing the maximum overshoot limit to 61.8 Hz and we support this modification to the performance requirements. However, we expect this concern will resurface if standards requiring minimum frequency response are not implemented and further declines in system frequency response are observed. NPCC recommends that NERC develop standards for unit governing response that are consistent with and support the reliability objectives of standards PRC-006 (UFLS) and PRC-024 (Generator Performance). **The SDT agrees, though this is outside the scope of its activities.** NPCC also notes that it may not be possible for the Planning Coordinators to design a reliable UFLS program that will arrest and recover declining frequency if an excessive number of generators are exempted from meeting the underfrequency performance requirements in PRC-024. **The SDT agrees, though this needs to be addressed by Project 2007-09 SDT.** Hydro-Quebec TransEnergie has technical parameters that differ from those specified in Requirements R6 and R7. A Variance will be needed to address those specific concerns. **[Add variance to this standard?]**
Response:	
Southern Company	--- R8: It is problematic for a loosely organized group of Planning Coordinators to create and maintain a database. There are several practical and compliance issues with this. This should be assigned to an entity with clear responsibilities and pro
Response: [Looks like comment got chopped off, but may be same as SERC's below.]	
ERCOT ISO	Comment 1- May need to consider defining the meaning of region (Region) in the NERC Glossary so it is clear for the responsible entities for this standard. Comment 2 Will it be necessary for ERCOT ISO to have a procedure for coordinating with groups of Planning Coordinators, since we are essentially a group of one? Maybe language could be added to the standard to clarify for this situation. Comment 3 - It would be appropriate for the load referenced in the imbalance calculation in requirement R6 to include system (island) losses. The standard should be clearer.

Organization	Question 8 Comments:
Response:	
Electric Market Policy	
Midwest ISO Stakeholders Standards Collaborators	R3 requires the Planning Coordinator(s) to consider historical events and system studies that may form islands. Creating islanding scenarios that are not historical events will be highly speculative and require a PC(s) to address hypothetical sequence(s) of events that is unlikely to occur. Further, for larger PCs the number of potential islands could grow significantly if an unlimited number of contingencies are considered. Running dynamic simulations to design coordinated UFLS programs for multiple islanding scenarios would be a huge burden. The SDT should provide criteria for the PC to use in determining UFLS islands similar to that developed for the TPL-004 Category D criteria. **The SDT recognizes the difficulties that could be encountered in identifying islands. Nevertheless, there may be portions of a system that obviously have a higher likelihood of islanding as compared to others. How extensive an analysis to identify islands needs to be is a judgment that cannot be written into a standard and must be left to the discretion of the entities involved. The standard only requires that criteria for identifying islands be developed and applied.** R2 We would suggest removing the word "consistent" because the program can not be applied consistently across the MRO Region. The Canadian systems need to shed more load than the US portion of MRO. We need to focus on coordination issues between geographic areas, not on consistent application across a NERC region. Perhaps what was intended is to state that load shedding should be applied uniformily across any island footprint. **[Note to SDT: I think I agree with this or else give them a regional variance.]** R4 - Revise text so that the "agreement" between all entities is well documented through several examples: meeting minutes, a formal agreement to work together, results of common drills, examples of coordination of UFLS models, etc.) We would propose that the assessment for non compliance would be located in the formal agreement to work together since all parties should understand the risk or consequences of the group effort. These standards do not appear to consider or address if capacitors should be automatically tripped during UFLS to avoid overvoltage conditions. Do other standards address this or does this draft standard need to be modified? **Please see R6.4. The SDT does not believe that requiring capacitor tripping in the standard is necessary.**
Response:	

Organization	Question 8 Comments:
SERC UFLS Standards Drafting Team	R8: It is problematic for a loosely organized group of Planning Coordinators to create and maintain a database. There are several practical and compliance issues with this. This should be assigned to an entity with clear responsibilities and processes to accomplish the task. Additionally, annually and database is unnecessarily restrictive given the study is only required on a 5 year basis and in light of existing data collection processes. Recommend revision R8 as follows: shall compile/assemble information provided by their Transmission Owners and Distribution Providers for use in UFLS assessments and event analyses. Databases should add value and not create extra work that does not directly contribute to the completion of the study.--- R7.1 and 7.2 could have the effect of shifting the generators burden of staying on line to the load customer who must be shed to account for the generators less-than-expected frequency performance. The generators must be modeled because that is the way they perform, but an exception for frequency support must be difficult for a generator to obtain.--- **Per R5 of the first draft of PRC-024-~~0~~1, Generator Owners will need to document, subject to peer review, any generator under-frequency trip settings that fall outside the acceptable boundary defined by PRC-024-1, Attachment 1.** R10 should say ?shall implement the UFLS program rather than shall provide load tripping in accordance with the UFLS program because the phrase ?provide load tripping could be confusing.--- R1 through R8: The concept of PC's joining a group to design a UFLS scheme is flawed. Compliance should never be assessed on a group basis. Each PC (or TP) must be allowed to demonstrate compliance to the standard independently so compliant PCs/TPs are not penalized along with the non-compliant one(s). The standard should be applicable to individual PC's/TPs to design their UFLS scheme to meet the other requirements. The performance characteristics insure that the schemes from different PC's/TPs will coordinate. However, if a group approach is mandated, then sub-regional groups must be allowed in lieu of regional groups.--- R4 is an unnecessary complication, and should be deleted. A procedure for identifying islands between Regions is not necessary. What if there are no credible islands between Regions? R5 ensures that when credible islands between Regions are identified that all affected entities jointly study UFLS scheme effectiveness within the island.--- R6: Does this requirement say that performance requirements must be met only at a 25% imbalance? Or is it requiring performance requirements to be met at lower imbalances too? If yes, we recommend performing both a 25% and a 15% imbalance test to add clarification.--- **Any percentage between 0 and 25.** R10: Does each DP have to specifically meet the UFLS scheme? For example, if the UFLS scheme is for 30% load in 3 steps of 10% each, some small DP's may not be able to achieve that fine a resolution. Some allowance should be made for aggregating DP's to meet the overall scheme. This allowance should be achieved by making the TO responsible for implementing the UFLS scheme. The TO has a wider area of control and responsibility and is therefore in a better position to coordinate the

Organization	Question 8 Comments:
	implementation.--- **Any allowance is acceptable as long as compliance with the performance characteristics in R6 is achieved.** Unless there is a high bar in PRC-024 to obtain an exception, this passes the responsibility for generators to support frequency on to the loads (to support frequency by shedding). To compensate this standard needs a requirement for generators which do not coordinate with the R6 requirements to arrange for load to be shed to make up for their generator tripping.--- **As mentioned above, per R5 of the first draft of PRC-024-~~0~~1, Generator Owners will need to document, subject to peer review, any generator under-frequency trip settings that fall outside the acceptable boundary defined by PRC-024-1, Attachment 1. Since this standard does not apply to Generator Owners, the preceding comment should be directed to Project 2007-09 which covers PRC-024-~~0~~1.** R7.1: This should not require the modeling trip settings of all generators that trip at or above 58.0 Hz. Since most generators have trip settings for reduced frequency that holds for long periods (e.g. 30 minutes), this would require modeling trip settings of almost all generators. It should only require the modeling trip settings of generators that would trip within the performance envelope defined by R6.1 and R6.2.--- R7.2: This should not require the modeling trip settings of all generators that trip at or below 61.8 Hz. Since most generators have trip settings for higher frequency that holds for long periods (e.g. 30 minutes), this would require modeling trip settings of almost all generators. It should only require the modeling trip settings of generators that would trip within the performance envelope defined by R6.3.--- It is not clear if the standard requires one specific UFLS scheme for the entire Region. One scheme for the Region should not be mandated. Flexibility should be allowed for different schemes within the Region as long as each scheme meets the performance requirements. **[Note to SDT: I think I agree with this or else give them a regional variance.]**
Response:	
FRCC Standards & Operations Departments	We appreciate the Drafting Teams efforts on this very difficult standard and would offer the following suggested clarifications:R8. Each group of Planning Coordinators shall create and annually maintain a UFLS database containing relay information provided by their Transmission Owners and Distribution Providers for use in UFLS assessments and event analyses.Suggest rewording R8 as follow: R8. Each group of Planning Coordinators shall maintain a UFLS database which identifies the participating Planning Coordinators, contributing entities and contains information (as defined in R9) provided by their Transmission Owners, Distribution Providers and Load Serving Entities for use in UFLS assessments and event analyses.Suggest adding Load Serving Entities to R9.R10. Each Transmission Owner and Distribution Provider shall provide load tripping in accordance with the UFLS program designed by the group of Planning Coordinators for each region in which it operates.Suggest rewording R10 as follows: Each Transmission Owner, Distribution Provider and Load Serving Entity shall provide forecast load tripping in accordance with

Organization	Question 8 Comments:
	the UFLS program designed by the group of Planning Coordinators for each region in which it operates.
Response:	
Florida Municipal Power Agency and Select Members	
MRO NERC Standards Review Subcommittee	R1 - Reword the requirement to state the Planning Coordinators within a region shall have an agreement with all the Planning Coordinators rather than creating a new group. (For example similar to agreement requirements between BAs in EOP-001, between GOs and transmission entites in NUC-001, and RCs to form an agreement in IRO-001 R7.) Proposed wording for R1: "Planning Coordinators shall have agreements with all Planning Coordinators in the region, that shall, at a minimum, contain provisions for cover fulfillment of the subsequent UFLS requirements in the standard."This agreement would clarify how "group" responsibilites for compliance and penalties would be assigned to its member entities. For example, would all Planning Coordinators be non-compliant, if one or more members of the group is non-compliant or if a group could not come to consensus on elements needed to fullfill a requirement? Would the financial penalty be shared among the group or would each member be assessed separate penalties? R2 We suggest the following revised wording, "shall design a load shedding program or multiple load shedding programs so that all areas of the region are covered." In the MRO, the Canadian portions of the system need to shed more load than the U.S. portion of the system. There needs to be coordination within each potential island, but not necessarily consistent across each, entire NERC region. Perhaps what was intended is to state that load shedding should be applied uniformly across an island footprint. R4 - Revise text so that the "agreement" between all entities is well documented through several examples: meeting minutes, a formal agreement to work together, results of common drills, examples of coordination of UFLS models, etc.) We would propose that the assessment for non-compliance would be located in the formal agreement to work together since all parties should understand the risk or consequences of the group effort. R6.1 To match the design emphasis that is included in R6.2 and R6.3, we suggest . . . no less that 58.0 Hz per simulated event. R8 - Since the interpretation of "annually" can vary widely, we suggest this rewording, "each calendar year and within 15 months

Organization	Question 8 Comments:
	of the last update".
	R9 If the inclusion of Transmission Owner is determined to be redundant, reword to, Each Distribution Provider shall provide. . ., as noted in response to Q1.b.
	R10 If the inclusion of Transmission Owner is determined to be redundant, reword to, Each Distribution Provider shall provide . . ., as noted in repsonse to Q1.b.
	add R11 - Since reactive power device overvoltage or underfrequency protection may be included to the UFLS program assessment, we suggest adding the Requirement, "R11. Each Distribution Provider and Transmission Owner shall provide its reactive power device overvoltage or underfrequency protection information in the format and according to the schedule specified by the applicable Planning Coordinator." [If this requirement is added and includes the Transmission Owner, then the Transmission Owner should be included in the Applicability section.]
	add R12 - Since reactive power device overvoltage or underfrequency protection should be included in the UFLS program design for a specific island, we suggest adding the Requirement, "R12. Each Distribution Provider and Transmission Owner shall provide reactive power device tripping in accordance with the UFLS program designed by the applicable Planning Coordinator for each region in which they operate." [If this requirement is added and includes the Transmission Owner, then the Transmission Owner should be included in the Applicability section.]
	The SDT does not believe such requirements are necessary. Any reactive power device overvoltage or under-frequency protection needed to comply with R6.4 would need to be included in the assessment.
	add R13 - Since generator off nominal frequency protection information may be included to the UFLS program assessment, we suggest adding the Requirement, "R13. Each Generator Owner shall provide its off nominal frequency protection information in the format and according to the schedule specified by the applicable regional group of Planning Coordinators."
	The SDT does not believe this requirement is necessary. Per R5 of the first draft of PRC-024-~~0~~1, the Planning Coordinators will have information on generator under-frequency trip settings that fall outside the acceptable boundary defined by PRC-024-1, Attachment 1 and may include this in their database.
	add R14 - Since the coordination of generator off nominal frequency protection should be included to the UFLS program design for a specific island, we suggest adding this Requirement "R14. Each Generator Owner shall have evidence that they provided any coordination that is required by the applicable regional group of Planning Coordinators to meet UFLS program specifications."
	The SDT does not believe this requirement is necessary. Coordination between generator off-nominal frequency

Organization	Question 8 Comments:
	tripping and UFLS is already being achieved between this standard and draft PRC-024-~~0~~1. The need for different design criteria (performance characteristics) for sub-regions requiring UFLS percentages substantially larger than 25 percent will need to be addressed through regional variances. It is not clear if the standard requires one specific UFLS scheme for the entire Region. One scheme for the Region should not be mandated.Flexibility should be allowed for different schemes within the Region as long as each scheme meets the performance characteristics. ~~[Note to SDT: I think I agree with this or else give them a regional variance.]~~ Below is a list of technical requirements or issues the MRO NSRS would like the UFLS DT to consider for either a reference document or for regional variences. A. Limited Number of Island Loads - What allowance should made for Distribution Providers with a limited number of loads in a designated island? **Any allowance is acceptable as long as compliance with the performance characteristics in R6 is achieved.** B. 58 Hz Limit - Consideration should be given to circumstances in some islands where a lower frequency limit would allow better UFLS program performance. For instance the the Canadian example mentioned above. **Please propose a regional variance.** C. Coordination with the Proposed PRC-024 Standard - Consideration should be given for proper coordination for of this standard (UFLS) with the PRC-024 standard especially with reguard to off-nominal frequency settings for generation. **As mentioned above, this standard is being coordinated with PRC-024-~~0~~1.** D. Reference Document - We think it would be valuable to develop a companion reference document that may contain the following expectations and intentions: - The intent of this standard is to ensure UFLS programs are effective, and to the extent possible, that potential problems have been addressed in the design phase.- This standard should achieve an appropriate level of reliability and not just the least common denominator. An evaluation should be made to determine if the minimum load shedding requirement is sufficient and appropriate for a given geographic region. Although no geographic region (potential island) is obligated to exceed the minimum load shedding requirement, load shedding beyond the minumum requirement is encouraged when there is an identified advantage of doing so. - Overall coordination issues are easier to satisfy for programs that shed the minimum amount of load. Such programs will be better behaved over the smaller range of overloads, but the system will collapse if loss of generation (or import) exceeds the amount of load shed. Larger, more aggressive load shedding programs will provide a larger safety net at the expense of wider voltage and frequency deviations, and generation in those areas will need to accept more off-nominal frequency exposure to achieve coordination with load shedding. - UFLS analysis has to deal with considerable uncertainty in a multitude of variables. It is assumed that conflicting performance requirements and tradeoffs will be documented and resolved through application of engineering judgment.- This standard acknowledges that performance measures such as frequency and voltage deviation are subjective. Both voltage and frequency are influenced by hard-to-quantify

Organization	Question 8 Comments:
	factors that vary in real time, such as load damping, the net governor response, and inertia of spinning on-line units. Such performance measures can only be applied in consistent fashion to a tightly defined set of qualifying assumptions. - This standard acknowledges that UFLS is basically a last ditch effort to prevent system collapse and that it has limits. It is not possible to achieve desired performance for all of the unlikely events that may occur in real life. - Performance characteristics given in this standard should be treated as design targets or design guidelines. Studies run to develop UFLS programs may indicate different design criteria is appropriate as part of the overall compromise that has to be struck between performance and the level of load shedding coverage that is desired.- There is no perfect tool for studying UFLS, and this standard is not meant to prescribe any particular engineering approach to system analysis and review of UFLS performance. For example, the equivalent inertia method allows for sensitivity analysis and broader insight into the frequency decay dynamics. Likewise, the full transient stability case is more useful for simulating actual disturbance conditions including voltage transients. **The SDT agrees with many of the guiding principles described above, but does not agree that a reference document is necessary or that standard requirements should be viewed as design targets or guidelines. The SDT assumes that reasonable assumptions pertaining to load damping and governor response will be made in the UFLS assessments, and that inertia will be representative of the systems studied. As mentioned above, the need for different design criteria (performance characteristics) for sub-regions requiring UFLS percentages substantially larger than 25 percent will need to be addressed through regional variances. Nothing in the standard precludes the use of Equivalent Inertia Analysis in the UFLS design process, but the SDT believes that dynamic simulations are the only appropriate means of assessing compliance to the performance characteristics in R6.**
Response:	
Kansas City Power & Light	1. What is the engineering basis for any of the boundary and threshold criteria established by requirement 6 and its sub-requirements? These prescribed requirements may not fit with already established UFLS systems and to justify the expense of changes there should be a sound engineering basis for doing so.2. R9 requires Transmission Owners and Distribution Providers according to a schedule and format specified by the Planning Coordinator, but does not require Generator Owners to provide generator protection information. Recommend the SDT consider the inclusion of generator information in the appropriate places in these requirements.
Response:	
IRC Standards Review Comittee	R3 requires the Planning Coordinator(s) to consider historical events and system studies that may form islands. Creating islanding scenarios that are not historical events will be highly speculative and require a PC(s) to address hypothetical sequence(s) of events that is unlikely to occur. Further, for larger PCs the number of potential islands could grow significantly if an unlimited number of contingencies are considered. Running dynamic simulations to design coordinated UFLS programs for multiple islanding scenarios would be a huge burden. The SDT should provide criteria for the PC to use in determining UFLS islands similar to that developed for the TPL-004 Category D criteria. The fourth bullet in R5 is unnecessary since (all assets)

Organization	Question 8 Comments:
	(assets in Island 1) (assets in island 2) - .. = (remaining assets not in any other island)Alternatively, the SDT may want to consider a requirement to perform one or more ad hoc stress tests that can be used to define islanding conditions. If PC passes the stress test, than there is no obligation to define an island within the PC; if the PC fails the stress test, than the PC must use the results as a partial (or complete) basis for defining one or more PC islands
Response:	
Cowlitz County PUD	Past experience has proved from efforts to comply with other data request mandated standards a disconnect on what specific data needs to be on hand for proper modeling. Keep in mind that the DP usually does not have the expertise, including many TOs, on what data will be needed. I would suggest there be a requirement that the PC not only develop the data set required, but actively (not passively) communicate to its DPs and TOs what is required. Simply expecting entities to stumble around in a web site and find the requirements complicates compliance efforts. Please note that I am not an expert in UFLS schemes and offer my limited knowledge as a compliance and distribution engineer. Thank you for the opportunity to join in this venue.
Response:	
Edward C. Stein	
Colmac Clarion	
City of Bedford	Distribution providers with fewer than 10,000 meter should be exempted for the UFLS program because their ability to effect the stability of the electrical grid is minimal and the cost of installing and maintaining the system would excessive.
Response:	
Alabama Municipal Electric Authority	In requirement 10, "R10. Each Transmission Owner and Distribution Provider shall provide load tripping in accordance with the UFLS program designed by the group of Planning Coordinatorsfor each region in which it operates.", it requires the Distribution Provider to provide load tripping. This seems to imply that the Distribution Provider would not be able to satisfy this obligation in aggregate from its Balancing Authority or Transmission Operator through its power supply contracts. The requiement to provide load tripping is especially troublesome for small entities that have only one feeder supplying the load of its end use customers. Additionally a small entity that is registered as a Distribution Provider that has less than 100 MWs of load will provide little help in affecting the frequency of the BES. The SDT should consider a class of Distribution Providers and not all Distribution Providers.
Response:	

Organization	Question 8 Comments:
US Army Corps of Engineers	
NIPSCO	Any standard neededs to be very general- should include the effect of load on frequency;Define what amount of load they require to trip; Include rate of frequency change protection.Only require planned load tripping; Actual load is much more difficult to predict on lower voltagecircuits.
Response:	
Public Service Electric and Gas Company	
Central Lincoln	
SPP System Protection and Control Working Group	None at this time.
Long island power Authority	Consider rewoeding R10 to better limit the Compliance aspect for the DP to implement setting UFLS relays based on the forecasted loads projected for the peak period. Suggest this R10 - The DP once per calendar year shall review the forecasted loads it is serving and provide for UFLS in accordance with the UFLS program designed by the group of planning Coordinators for each region in which it operates.
Response:	
Exelon	There is a concern with high frequency requirements because they are not clear as to what should occur or how it should be mitigated. If island frequency is greater then 60.7 HZ for more than 30 seconds what type of action needs to occur? What is the technical justification for these levels? In the previous Characteristics document the high voltage levels were different than the levels in this draft standard. Due to the inherent difficulty in accurately postulating load and generation islands, establishing frequency limits for such islands is even more difficult. There should be a criteria as to how the studies are done (including islanding criteria and size) if there are going to be bounds placed on the frequency result of the simulation. If the timing components (4,10,20 seconds) are removed, then regions should establish minimum generator tripping standards for load shedding. Unit tripping should be a balance between limiting cumulative damage while at the same time coordinating with load shedding levels in order to arrest frequency decline.Disagree with requirement 5. Criteria for island formation and the resulting requirements for mitigation should be included in a standard where affected parties may participate through the open and fair NERC process. There should not be some unspecified criteria left up to various entities with no oversight or standaridized

Organization	Question 8 Comments:
	development process. It would be very difficult if not impossible to determine how islands will be formed and where load will remain intact.
Response:	
ReliabilityFirst Corporation	SDT has to develop a mechanism to make sure all the loads are accounted for.
Response:	
Arkansas Electric Cooperative Corporation	R7.2 the wording "... trip at or below 61.8 Hz" implies that any generator with a trip setting below 61.8 must be modeled. If a generator has an UNDER-frequency trip setting below 58 Hz then it falls into this catagory. Was this the intent? If the intent was to capture those units with OVER-frequency trip setting above 61.8 Hz then the wording needs to be changed to "trip at or above 61.8Hz".The drafting team did a good job.
Response:	
System Protection & Control	There needs to be clarification as to loads and generation in this standard. If the intent is for the System to be secure for loss of xx amount of generation at summer peak and at winter peak in the planning model then that should be stated. In short, there needs to be further clarification on the relationship in regards to compliance within the Planning Model and the actual System Loads and Generation. Some entities in some regions require compliance with load shed percentages real time, 24/7. Others, only for the summer peak, and others for both summer and winter peaks. While these questions relate to measurements, it would be beneficial to know beforehand the SDT's thinking on these before implementation begins.
Response:	
Duke Energy	--- Similar to the response for 5, the team should consider simplifying the requirements by stating points that are just an offset of the PRC-024 requirements. As noted in the webinar, the overfrequency points do not coordinate with the PRC-024 curve at
Response:	
ReliabilityFirst	
Illinois Municipal Electric Agency	IMEA recommends the following language from the Background/Information section of the comment form be included under Section B. Requirements, R2: Planning Coordinators may elect to use their Regional Standards Development process to develop the programs (but this is not required) or they may determine that their existing programs fully meet the requirements of this

Organization	Question 8 Comments:
	proposed continent wide standard. IMEA believes the standard should only apply to areas where there are required UFLS programs that are in existence and not applied to all load if those loads are already covered in an existing UFLS program.IMEA also recommends that Regional Entities be directed to not include registered functions other than PC, TP, and DP in the applicability section of their region-specific PRC-006 standard.
Response:	
Hydro-Québec TransEnergie (HQT)	HQT recommends that NERC develop standards for unit governing response that are consistent with and support the reliability objectives of standards PRC-006 (UFLS) and PRC-024 (Generator Performance).HQT also notes that it may not be possible for the Planning Coordinators to design a reliable UFLS program that will arrest and recover declining frequency if an excessive number of generators are exempted from meeting the underfrequency performance requirements in PRC-024.HQT, being in the Québec Interconnection, has technical parameters that differ from those specified in Requirements R6 and R7. A Variance will be needed to address those specific concerns in regards to frequency tresholds and parameters.
Response:	
AEP	Wouldn't PRC-006-01 R5 be a SPS with all of it's attendant liabilities. Isn't NERC trying to minimize SPS schemes? PRC-006-01 R5 and EOP 003-1 philosophy would need to agree. PRC-006-01 R5 is written from the standpoint that one is able to predict island formation whereas EOP 003-1 is written to respond to island formation in whatever form it takes by shedding load (EOP 003-1 R6). EOP 003-1's purpose is to protect the interconnection whereas PRC-006-01 R5 would seem to require opening up ties. There seems to be a disconnect here. However, if the UFLSDT does goes forward with this thinking, then AEP would suggest small island formation as likely being more successful than large island formation.Another interpretation of the two standards would be that PRC-006-01 R5 is intended to be designed as an automatic first option. If that option fails, then EOP 003-1 is to be followed by the transmission operator.
Response:	
Ontario Power Generation	The SDT should be commended for producing a very good standard. There is one issue however that may negate the outcome of UFLS effort. Maximum permissible frequency overshoot of 61.8 Hz specified in R6.3 appears too high. It would quite likely result in hard to predict loss of many large fossil and nuclear units. Past system disturbances provide enough evidence of such thermal power plant response that typically leads to system collapse. This is a fundamental issue for the design of an effective UFLS scheme. What was the reason for not adopting a lower frequency overshoot value, especially considering that multi-step UFLS schemes should be able to accommodate that?
Response:	

Organization	Question 8 Comments:
We Energies	We Energies disagrees with the overall approach that the Standard Drafting Team (SDT) has taken with the latest draft of the continent-wide UFLS standard. FERC rejected the original PRC-006 due to its fill-in-the-blank nature. The continent-wide standard is still a fill-in-the-blank standard with the Planning Coordinator (PC) required to fill in the blanks. In addition, the standard does not require the PC to involve the Distribution Provider (DP) and Transmission Owner (TO) in the development of the UFLS program. Also, the standard requires the DP and TO to implement without question whatever UFLS program has been designed by the PC. We are concerned that the standard places a burden on the DP and TO to shed additional load to make up for generators which trip outside of the criteria specified in draft NERC standard PRC-024.A continent wide UFLS standard must set the minimum level of UF tripping for each Interconnection. The continent wide standard must do this by specifying the minimum amount of loadshed, trip frequency steps, and time delay criteria for UFLS relays. The continent wide standard must remain silent on criteria, such as islanding, that is above and beyond the minimum amount of loadshed, trip frequency steps, and time delay criteria. Regional UFLS standards must be the vehicle for going above and beyond the minimum requirements of the continent wide UFLS standard. Islanding is one aspect that can be addressed in regional standards if necessary. If the above comments are not adopted by the SDT, the following additional comments address the standard as written. As mentioned previously, this standard does not have a requirement for the PC to involve the DP and TO in the design of the UFLS program. In addition, the standard requires the DP and TO to implement without question whatever program the PCs design without any concurrence from the DPs and TOs. There must not be any loopholes in this standard which would force the DP or TO to shed additional load for a generator that could meet the criteria specified in draft NERC standard PRC-024. Therefore, R2 must be revised to add a sentence that requires the PC to involve the DP and TO in the design of a mutually agreeable UFLS program. Similarly, R10 must be revised such that it states that the DP and TO will implement the mutually agreed to UFLS program. Lastly, in the RFC region there are only three PCs. This standard is placing a burden and regulatory risk on these three entities in RFC. It is not consensus for three entities to dictate a UFLS program for an entire region. The last sentence of R4 needs two clarifications. First, the text neighboring entities needs to be defined. It is unclear if the text neighboring entities refers to a neighboring PC, DP, TO, GO, Region, etc. Second, the term assessment needs to be referenced in a more specific manner. Does the term assessment refer to island assessments or the UFLS program assessment required in R7 The last bullet item in R5 needs clarification. First, what is meant by the text at least one island? Does this mean the default island is the Region's electrical boundaries? Second, if a DP or TO's load is part of multiple islands, what mechanism will prevent the DP or TO being issued conflicting UFLS trip settings (e.g. Island 1 requires the DP to set its relays to trip at 59.0 Hz, while Island 2 requires that same DP to set its relays to trip at 58.7 Hz)? R7.1 and R7.2 need to be revised since as these sub-requirements are currently written all units with automatic UF tripping installed would be required to be simulated. Specifically, R7.1 requires units that trip between 58.0 Hz to positive infinity to be simulated and R7.2 requires units that trip between 61.8 Hz and 0 Hz to be simulated.
Response:	
PacifiCorp	No comment.
NextEra Energy	No comment.

Organization	Question 8 Comments:
Resources, LLC	
American Transmission Company	ATC believes that the SDT should develop official definitions for the following three terms used throughout the document: a) "under-frequency load shedding" (along with under-frequency load shedding program) b) island and region. All three terms warrant a definition in order to be able to assess whether the plans developed pursuant to the standards are consistent between and among the Planning Coordinators. Although these terms may have some generally accepted meaning, there likely is a difference among Planning Coordinators and those differences could potentially lead to enforcement issues. The failure to define these terms by NERC will result in each Planning Coordinator providing their individual perspective that could result in either gaps in the region or difference in what is meant by an island within a region, and what constitutes an under-frequency load shedding program. R2 To make the requirement apply to each PC rather than a group, we suggest this rewording, Each Planning Coordinator shall design . . . that was developed in coordination with the applicable regional group(s). R2 - To allow appropriate UFLS program differences amoung islands within a single Regional Entity, we suggest this rewording, " . . . under frequency load shedding programs for consistent application across each island within the Region." Some islands in the MRO need to shed more load than other to achieve reasonable frequency recovery. R3 To make the requirement apply to each PC rather than a group, we suggest this rewording, Each Planning Coordinator shall develop . . . in coordination with the applicable regional group(s) to apply to select portions of the Bulk Electric System that are designated as islands?.R4 To make the requirement apply to each PC rather than a group and include corordination within the Region, we suggest this rewording, Each Planning Coordinator shall develop a procedure for coordinating with groups of Planning Coordinators within its Region(s) and groups of Planning Coordinators in neighboring regions . . .R5 To make the requirement apply to each PC rather than a group, we suggest this rewording, Each Planning Coordinator shall identify . . . as a basis for designing a UFLS program with the applicable regional group(s) R6 To make the requirement apply to each PC rather than a group, we suggest this rewording, Each Planning Coordinator shall specify . . . load shedding program in coordination with the applicable regional group(s) that are required to meet the following . . .R6.1 To match the design emphasis that is included in R6.2 and R6.3, we suggest . . . no less that 58.0 Hz per simulated event. R7 To make the requirement apply to each PC rather than a group, we suggest this rewording, Each Planning Coordinator shall conduct . . . with its applicable regional group(s). R8 To make the requirement apply to each PC rather than a group, we suggest this rewording, Each Planning Coordinator shall create . . . in coordination with its applicable regional group(s) . . R8 - Since the interpretation of "annually" can vary widely, we suggest this rewording, "each calendar year and within 15 months of the last update".R9 Since the Transmission Owner reference is redundant, we suggest this rewording, Each Distribution Provider shall provide.. .. R10 Since the Transmission Owner reference is redundant, we suggest this rewording Each Distribution Provider shall provide . . . R11 - Since reactive power device overvoltage or underfrequency protection may be essential to the UFLS program assessment, we suggest adding the Requirement, "R11. Each Distribution Provider and Transmission Owner shall provide its reactive power device overvoltage or underfrequency protection information in the format and according to the schedule specified by the applicable regional group of Planning Coordinators." [If this requirement is added and includes the Transmission Owner, then the Transmission Owner should be included in the Applicability section.R12 - Since reactive power device overvoltage or underfrequency protection may be essential to the UFLS program design, we suggest adding the Requirement, "R12. Each Distribution Provider and Transmission Owner shall reactive power device tripping in accordance with the UFLS program desinged by the group of Planning Coordinator for each region in which

Organization	Question 8 Comments:
	they operate."R13 - Since generator off nominal frequency protection information may be essential to the UFLS program assessment, we suggest adding the Requirement, "R13. Each Generator Owner shall provide its off nominal frequency protection information in the format and according to the schedule specified by the applicable regional group of Planning Coordinators."R14 - Since the coordination of generator off nominal frequency protection is essential to the UFLS program design, we suggest adding this Requirement "R14. Each Generator Owner shall have evidence that they provided any coordination that is required by the applicable regional group of Planning Coordinators to meet UFLS program specifications." Reference Document - Due the number and complexity of the elements that need to be considered to develop effective UFLS program designs and for fulfilling the requirements in this standard (e.g. island identification, number of load tripping steps, frequency settings, time delays, percentage of load per step, system inertia, governor response, etc.), we suggest that a reference document be developed to provide useful information regarding automatic UFLS programs to the applicable entities.
Response:	
Luminant Power	Several of the requirements are for a group of Planning Coordinators. From a Compliance perspective, how will the actual requirements be enforced on the group, or will the requirements be enforced on each individual Planning Coordinator?
Response:	
Ameren	There is nothing in the standard that provides direction in terms of measuring whether an entity has effectively implemented a UFLS program.
Response:	
FirstEnergy Corp	1) On requirement R7.1 we suggest adding the words under-frequency before the phrase trip settings for clarity.2) On requirement R7.2 we suggest adding the words over-frequency before the phrase trip settings for clarity.3) As stated in question 5, the frequency requirements for generators should be in this standard PRC-006 not PRC-024.4) The new standard does not properly address the requirements of PRC-009 to analyze the performance of an UFLS program following an under frequency event. If the standard is retire PRC-009, it needs to properly cover the analysis of these events and not refer them to ERO Rules of Procedures. Since PRC-004 covers the analysis of System Protection misoperations and PRC-016 covers SPS misoperations, UFLS events including misoperations also must be covered in a standard to ensure review.5) On requirement R.1 the use of the word region should be replaced with Regional Enity territory for clarity so that region may not be misinterpreted to be RTO region or some other sub-region of a Regional Entity territory. We suggest the requirement be written to say Each Planning Coordinator shall join a group consisting of all Planning Coordinators within the Regional Entity territory it performs the Planning Coordinator function.6) We support the following MISO comment. R3 requires the Planning Coordinator(s) to consider historical events and system studies that may form islands. Creating islanding scenarios that are not historical events will be highly speculative and require a PC(s) to address hypothetical sequence(s) of events that is unlikely to occur. Further, for larger

Organization	Question 8 Comments:
	PCs the number of potential islands could grow significantly if an unlimited number of contingencies are considered. Running dynamic simulations to design coordinated UFLS programs for multiple islanding scenarios would be a huge burden. The SDT should provide criteria for the PC to use in determining UFLS islands similar to that developed for the TPL-004 Category D criteria.
Response:	
CenterPoint Energy	1. CenterPoint Energy again commends the SDT for addressing the difficult issue of Applicability. CenterPoint Energy suggests the SDT also address the difficult issue of placing requirements within the proper category of reliability standard. CenterPoint Energy recommends placing Requirement 9, dealing with submittal of UFLS data, within a MOD standard (Modeling, Data, and Analysis). CenterPoint Energy believes the UFLS data will be used for modeling to facilitate dynamic simulation studies and, therefore, should be included in an MOD standard. 2. CenterPoint Energy appreciates the SDT attempt to clarify islanding. However, the SDT may have misinterpreted CenterPoint Energy comments on Draft 1. Reiterating our comment, CenterPoint Energy believes regional and/or predetermined islanding is not always applicable in an interconnection-wide region. In addition, the requirements dealing with a group of Planning Coordinators are also not applicable to an interconnection-wide region, such as WECC and ERCOT. With eight of the ten proposed requirements applicable to a group of Planning Coordinators, it appears eight requirements will be problematic for WECC and ERCOT. CenterPoint Energy recommends the following wording be included in Requirements 1 through 8: This requirement is not applicable in an interconnection-wide region.
Response:	
Independent Electricity System Operator	(1) We propose R5 to be expanded to require the Planning Coordinators to develop criteria for identifying potential islands, as follows:Each Planning Coordinator shall develop criteria, considering historical events and system studies, to select portions of the Bulk Electric System (BES) that can form an island(s) as a basis for designing a UFLS program. The identified island(s) shall include: .(2) R6 needs to be more precise regarding load. Suppose a station with 100MW of load has 20MW of distributed generation added that is anticipated to be in service during the ULFS calculation period (e.g. summer peak hour). Is the ULFS arming determined on basis of 100MW or 80MW of load This will make a big difference in Ontario if the GEA attracts significant amounts of the distributed generation.(3) The standard should include a requirement for mandatory testing/re-calibration period for both ULFS relays and generator under and over frequency relays. The Generator Operator/Owner needs an obligation to provide this information.(4) Governor action can help mitigate adverse effects of disturbances that affect frequency. Should this standard include some requirements for governor response?
Response:	
Xcel Energy	We feel R6.4 is not complete without consideration of other BES components, such as transformers and reactive devices. To ensure excessive voltage does not cause further damage or perpetuate the situation, we feel these additional components

Organization	Question 8 Comments:
	should be considered. We feel that the use of the word region in R1 is unclear. We assume the SDT intended to refer to the 8 NERC regions? (MRO, SPP, WECC, RFC, SERC, etc.) If so, please make that clear in the requirement.
Response:	

1) Individual or group.
Individual

2) Name
Barry Francis

3) Organization
Basin Electric Power Cooperative

4) Telephone
###-###-####
701-557-5642

5) E-mail
bfrancis@bepc.com

6) NERC Region (check all Regions in which your company operates)
MRO
WECC

7) Registered Ballot body segment (check all industry segments in which your company is registered)
1 - Transmission Owners
3 - Load-serving Entities
5 - Electric Generators

Summary Considerations:

- **Many of his comments seem predicated on an assumption that PRC-006 performance characteristics (R6) would apply to UFLS program percentages and load-gen imbalances over 25 percent as well as 25 percent.**
- **Coordination should be required but unsure how to resolve potential conflicts. Programs should be developed by the Regions. [I agree that coordination with neighboring regions is required, but I do not know how to resolve differences of opinion between regions. Perhaps this is nothing to worry about since it is likely to take care of itself. Are we trying to reach a consensus between regions, or just trying to share information and to create a forum for discussion? Obviously where breakups cause islands that straddle different NERC regions, we need to jointly evaluate that island. Even if this coordination is only to share information, it still allows everyone to learn from each other and is going to be quite valuable.]**
- **This standard seems to be driving towards lowest common denominator**

The SDT believes that what is behind the majority of the commenter's comments is a concern over sub-regional UFLS programs that need to be substantially more than 25[cag1] percent.

First, the SDT would like to clarify a possible misconception held by the commenter: The performance characteristics in R6 of the draft PRC-006 standard would NOT apply to UFLS program percentages and load-generation imbalances over 25 percent. It is correct that the generator off-nominal frequency tripping limits contained in the draft PRC-024 standard would apply at any UFLS percentage and imbalance. However, a UFLS program capable of shedding more than 25 percent of a system's load would only need to comply with the performance characteristics up to a 25 percent load-generation imbalance. Beyond a 25 percent load-generation imbalance, a UFLS program would be on its own, or else the Planning Coordinators within a region could devise other performance characteristics that would apply under load-generation imbalance scenarios greater than 25 percent.

The SDT understands the concern over bigger sub-regional UFLS programs. The SDT recognizes that a 60 percent capable UFLS program, for example, may have trouble complying with the performance characteristics even under a 25 percent load-gen imbalance scenario. The SDT is not convinced that it would be impossible to comply, but can see that it could be more difficult.

The commenter does not seem to acknowledging[cag2] the need for coordination among interconnected regions, a consideration that has weighed heavily in the SDT's deliberations. This may be because coordination can become troublesome in the presence of bigger programs. A bigger program in an exporting sub-region with limited interconnecting transmission, for example, is likely to set up further system separations should a UFLS event occur across a larger area. On the other hand, a bigger program in an importing sub-region should not cause coordination difficulties. The SDT has determined that the approach that is least intrusive on the flexibility to set UFLS design parameters within a region, but that addresses the need for inter-regional coordination, is to establish continent-wide performance characteristics as are now in the draft standard.

The SDT disagrees that there is a need to radically modify the two standards as the commenter is suggesting. Most of the North American systems have UFLS programs in the 25-30 percent of load range and should have no difficulty in complying with the draft performance characteristics. The Planning Coordinators within a region are not obligated by the draft standard to constrain the size of sub-regional programs for the sake of interregional coordination or any other reason. If necessary, a regional variance may be proposed.

The commenter's comments on PRC-024 seem predicated on an assumption that GOs will set their relays on this curve. This may be a valid concern in the unregulated environment. The SDT suggests the commenter comment on the draft PRC-024 standard on this point. Nonetheless, generator UF tripping curves are not new. The MRO region, even today, has such a generator UF curve (stair-step) that fairly closely tracks the draft PRC-024 curve. Therefore, the SDT is not certain that the commenter's comments regarding coordination of UFLS with generator tripping and elimination of these curves have been found necessary even in regions having sub-regional UFLS programs substantially greater than 25 percent. (Note: the commenter should re-review draft PRC-024 Attachment 1, Off-Nominal Frequency Capability Curve, because the time durations are longer than what the commenter has assumed in the commenter's Question 5 comments and in section 2.17 of Question 8 comments.)

8) Question 1a

Do you agree that creating a continent wide standard preserves the intent of utilizing specific expertise within the regions to develop UFLS programs that meet common performance characteristics?

Yes

Summary of Issues - Question 1:

- Technical approach is inappropriate and the team should provide its technical justification for the performance criteria

Response: The SDT disagrees that the technical approach is inappropriate. The technical justification for the performance characteristics lies chiefly in their coordination with generator under-frequency tripping limits in draft standard PRC-024, which in turn are based on turbine manufacturer's permissible life-time durations at off-nominal frequencies.

- Agrees that planning coordinators are the appropriate entity to establish the program; however, there are shortcomings to this approach – limited scope and should include subject matter experts (the planning coordinator may not be the subject matter expert). The Regions should remain involved in the process of developing the programs as they have the committee structure in place to accomplish.

Response: The team thanks the commenter for his support; however, does not see an alternate approach to assigning responsibility to the Planning Coordinator. FERC Order 672 indicates that requirements should be assigned to users, owners, operators and while the drafting agrees that the Regional Entities should be involved, the drafting team assigned the responsibility to the Planning Coordinator (a user, owner, operator). ~~However, t~~The drafting team feels that it has not precluded the involvement of the Regional Entity in the process nor precluded the Planning Coordinator(s) from electing to use their regional standards development (?)[cag3] process (an open and inclusive process) to establish the program.

9) Question 1a Comments:

See my detailed discussion under item 8, in it's entirety, but especially my sections 3.5 and 3.6. I believe a continent wide standard may be possible if we adopt a completely different type of measure but we cannot be setting performance details up front before the study work has been performed. Different sizes of programs have different performance characteristics, so a single set of performance characteristics will not meet the needs of all parts of North America.

Response: See SDT answer under Summary Considerations above. Most North American systems have UFLS programs in the range of 25-30 percent of load. If a sub-regional UFLS program substantially exceeding this range cannot comply with the performance characteristics, a regional variance should be proposed.

10) Question 1b

Do you agree that the SDT has assigned responsibility to the appropriate entity?

No

11) Question 1b Comments:

I do not know for sure if responsibilities are assigned to the appropriate entity, so I answered NO, when "I do not know" might have been more appropriate. To some degree, everyone needs to get involved at some level to ensure we have a loading shedding program in place to act as a saftey net. I am concerned that the transitions associated with "mandatory compliance" appears to actually be decreasing the level of coordination we have traditionally had. Good coordination is the key to ensuring reliability. Among other things, we need to keep the NERC regions involved in this process. They have the committee structure to facilitate coordination matters, and they can bring everyone together to jointly focus on the issues.

Response: See above.

12) Question 2:

The SDT has strived to draft the applicability in a manner that includes all load while avoiding assigning applicability to more than one entity for the same load. The Functional Model indicates the Distribution Provider is not defined by a specific voltage, but rather as performing the Distribution function at any voltage. Considering the Functional Model definition of Distribution Providers please indicate whether you believe it is necessary to assign applicability to "Transmission Owners with end-use Load connected to their Facilities where such end-use load is not part of a Distribution Provider's load".

No

13) Question 2 Comments:

It seems OK to consider transmission owners with end-use load connected to their Facilities as Distribution Providers, but I can see complications. How does a transmission owner with a small amount of end-use load have enough load to work with to satisfy the load shedding program description?[cag4] This implies they would have to coordinate with someone else. Taking this concept further, it seems like we need to ensure the right program is implemented in aggregate, but not worry too much about each responsible party meeting the exact program specification. We can take advantage of one party shedding a little too much at one stage and another shedding a little less to get the right fit in the end. This is sort of taking advantage of offsetting errors. This implies some type of group coordination based on geographic area is needed to ensure the collective load shedding need is fulfilled.

Response: TBD

Summary of Issues – Question 3:

1. Planning Coordinators should determine the appropriate analysis. As written, the implication is that a full transient stability program is needed to do this analysis. There are other equally valid analytical approaches, each with different strengths and weaknesses, and the group of Planning Coordinators should be allowed to use whatever tools they feel are most appropriate for quantifying this risk.

Response: Dig up response to the second posting The Planning Coordinators are permitted to use whatever methods, tools and analyses they wish to use in coming up with the UFLS program design and parameters. The draft standard would only require dynamic simulations of the whole regional system or the islands in the periodic UFLS assessments (R7).

2. Should try to prevent units from tripping off before the UFLS program plays out

Response: We agree but the only way to ensure units don't trip before UFLS plays out is to set requirements in the standard. The drafting team will forward the comments regarding the PRC-024 standard to the Generator Verification team. [cag5]

14) Question 3:
The proposed continent-wide standard requires that Planning Coordinators model the trip settings of any generators that trip at or above 58.0 Hz (Requirement R8) when verifying through dynamic simulation that the UFLS program design is adequate to meet the continent-wide performance characteristics specified in Requirement R6.

Do you agree with this approach to ensure that effectiveness of the UFLS program is not jeopardized by units that trip at or above the minimum frequency (58.0 Hz) at which the UFLS program may arrest frequency decline?
No

15) Question 3 Comments:
Some type of risk assesment is needed, but a dynamic simulation may not always be appropriate if there are other ways to get the answer we are looking for. This subject, and related topics, are addressed in the comprehensive discussion I included under item 8. Please consider all of my comments under item 8 to understand my concerns.

First of all, in some instances a regional (or subregional) load shedding program sheds more than the required minimum of load. A consequence is the expected minimum transient frequency will probably be below 58 Hz, at least for some set of conditions, so we are going to interpret "58 Hz" as 58 Hz or the minimum expected transient frequency of the regional (or subregional) program. This revised definition is what we consider to be important.

Some of the older wind generation will trip early due to inherent instability of that type of induction generation. This is not a planned activity, but it is still loss of additional generation. In MRO we felt the present magnitude of this impact was small (and unpredictable) and it could be included as part of the original assessment of the total load shedding requirement. (This will have to be reconsidered as additional wind generation is added.)

MRO expects that newer wind generation and virtually all of the conventional generation will be able to accommodate the generation off-nominal frequency tripping time delay requirements proposed by MRO. As far as we are aware, it appears the sole exception are owners of one model of gas turbine who may want to trip instantly at frequencies such as 58.2 Hz rather than accept brief dips below 58.2 Hz. In WECC, owners of similar units managed to comply with the comparable WECC generation off-nominal frequency tripping time delay standard. We hope this will be how it plays out in MRO after owners of these types of gas turbines take a closer look and their options.

MRO does not encourage the practice of premature tripping of generation but we made a provision in the MRO UFLS program definition to allow premature tripping on underfrequency provided it meets certain provisions. This provision also applies to small non-utility generation which might be on a feeder that is tripped with load. Basically we require a nearly identical size block of load to be shed at nearly the same time and location to compensate. Owners who wish to do this should have some responsibility to demonstrate they can satisfy this provision. The burden of proof should be on those who want an exclusion.

At this point we believe that the group of Planning Coordinators (or the applicable study group in general) should decide on the appropriate analysis method to review impacts. They can decide if such loss of additional generation is significant or not. If we are only dealing with one or two small units on a large system, then this hardly needs further study other than to demonstrate it is feasible to trip additional load at the time the generation trips. As far as assessments go, we feel there are various approaches that can be taken to do this type of risk assessment. As written, the implication is that a full transient stability program is needed to do this analysis. There are other equally valid analytical approaches, each with different strengths and weaknesses, and the group of Planning Coordinators should be allowed to use whatever tools they feel are most appropriate for quantifying this risk.

There are even ways to assess the risk of having units trip off early that do not rely on simulations, but instead just quantify the additional overload burden this adds to the island.

Let engineers figure out how to study the problems using whatever tools, methods, and calculations they feel are appropriate. However, as a general principle, we should try to prevent units from tripping off before the UFLS program plays out. Even more important, we should not allow any generation to trip via dedicated overfrequency relays (other than tripping actions directly or indirectly related to the inherent factory installed load rejection protection that we do not want to be messing with). The one exception would be when overfrequency tripping of generation is a planned activity that is a feature of the UFLS program used to rebalance load and generation.

16) Question 4:
The SDT added a requirement that requires the Planning Coordinators model, in the five year assessments, any automatic load restoration that is designed to assist in stabilizing system frequency (Requirement R9). The team decided to add this requirement as a result of a comment during the first posting. Do you agree that this requirement is necessary for reliability?
Yes

17) Question 4 Comments:
Any automatic feature of the load shedding program should be modeled in the ULFS Program assessment.

Response: The SDT agrees.

18) Question 5:
The SDT added a requirement in the underfrequency load shedding performance characteristics that requires (in simulations) frequency to not remain below 58.2 Hz for greater than four seconds cumulatively per simulated event (Requirement R6.2). The SDT added this requirement to better coordinate with the Generator Verification Project (PRC-024) tripping curve. Do you agree with this additional requirement?
No

Summary of Issues – Question 5:

1. The team should provide technical justification for the performance criteria

   Response: See SDT response above. The technical justification lies in coordination with generator off-nominal frequency tripping.

2. Overall load shedding performance and coordination with generation protection should be evaluated at the regional level (not continent wide level – inferred)

   Response: The creation of a continent-wide standard does not prohibit the creation of Regional Standards for UFLS. Regional Entities may develop other performance requirements through Regional Standards or Regional Variances as outlined in the NERC Rules of Procedure. This approach still allows each region to develop requirements that meet the specific needs of the region while still maintaining a continent-wide level of reliability.

3. Canadian portion of MRO cannot meet the performance criteria and MRO cannot meet the timeframe established in requirement R6

   Response: The team will be proposing a curve instead of three discrete points. This change may address the concerns with this requirement. Based on the revised requirements (reference revised requirements) MRO should evaluate if a Regional Variance is required. Come back to this…

4. Setting specific off-nominal frequency limits / criteria up front effectively sets the limit on how much load can be shed and drives all load shedding programs to the lowest common denominator which will reduce reliability

Response: For an imbalance up to and including 25% these performance characteristics must be met; however, the proposed standard does not include requirements for imbalances exceeding 25%. For an imbalance exceeding 25% the Regional Entities may develop other performance requirements through Regional Standards, Regional Variances, or Regional Criteria as outlined in the NERC Rules of Procedure.

19) Question 5 Comments:

Please provide the technical justification for this performance criteria.

This subject, and related topics, are addressed in the comprehensive discussion I included under item 8. Please consider all of my comments to understand my concerns.

We understand the SDT wants to ensure load shedding programs achieve quick frequency recovery and minimize underfrequency exposure. However we do not feel this requirement is the right way to go about that. This type of criteria is overly specific and should not be in the NERC standard. The recently developed MRO UFLS program which sheds 30% of system load appears to meet this criteria, but the Canadian portions of MRO which have higher load shedding requirements are unlikely meet this criteria. Aggressive load shedding programs in general will probably not satisfy this requirement. Frequency recovery, overall load shedding performance, and coordination with generation protection, should all be evaluated at the regional level by those who do the technical analysis of regional load shedding programs. In addition to study work, a lot of common sense needs to be applied. Several things need to be discussed to clarify our position.

First of all, we do not agree with the direction taken in PRC-024 to define off-nominal frequency settings for generation. That should never have been included as part of PRC-024. No technical justification was ever provided for the generation protection frequency setpoints and time delays suggested in PRC-024, and those setpoints and delays do not necessarily reflect actual equipment capabilities. NERC should not be defining generation off-nominal frequency protection standards such as those in PRC-024 unless this is only intended to be a starting point that can be adjusted, as needed, based on results of actual study work. It takes study work to define the expected worst case frequency recovery times of the load shedding program and off-nominal frequency exposure is strongly affected by the size of the load shedding program. Setting specific off-nominal frequency limits/criteria up front effectively sets the limit on how much load can be shed and drives all load shedding programs to the lowest common denominator. Obviously that will reduce reliability. Programs which shed more than the minimum required load will inherently experience lower frequencies and spend more time below 58.2 Hz.

We believe that load shedding program design should be based on achieving the quickest frequency recovery that is possible subject to satisfying all of the other conflicting design requirements and constraints, such as minimizing overfrequency problems, and in the end you are left with the engineering realities of what settings are needed on turbine/generator protection to achieve coordination. The folks who do the analysis at the Region level are in the best position to judge what is appropriate in the end. Final recommendations for turbine/generator protection will involve trade offs and compromises that have to be resolved by engineering judgment and a good deal of common sense.

We would like to point out that the risk to generation is somewhat less than implied by the generation underfrequency protection time delay settings and that being too conservative on the generation protection side will be a risk to system reliability. Consider that if premature generation tripping occurs that we are likely to initiate cascading loss of generation and go black. (The real loss of life exposure to power plants might be the restoration process of a black start plan[cag6], a plan which usually calls for this underfrequency protection to be disabled up front so they can pick the pieces back up.) In the context of a load shedding event, the risk to units is based on actual off-nominal frequency exposure, which is inherently something of a probability density function. For any load shedding program there are going to be certain combinations of overload and modeling assumptions where UFLS programs tend to stall out or where frequency recovery is sluggish. Think of this as narrow windows of vulnerability. For the majority of the conditions modeled, the frequency recovery is much quicker. A well designed UFLS program which is designed to force frequency recovery back towards 60 Hz can actually act as the first line of defense for generation and this is how the new MRO program was designed.

Even more troubling to MRO, and this should be equally troubling to all of the NERC Regions, are the very short time delays the PRC-024 has proposed at the higher frequencies (below 58.5 Hz for <= 10 seconds, below 59.3 Hz for <=30 seconds). In the MRO program design work, for the US portion of MRO where we have the smallest load shedding requirement, we spent approximately 8.7 seconds to 1.4 seconds below 58.5 Hz depending on what was assumed for governor response and other modeling details. The 10 second requirement for 58.5 Hz was just barely satisfied but keep in mind that we also want to set generation trip times so we have some comfortable margin between expected frequency recovery times and generation trip delays in case "real world" complications slow down frequency recovery. Likewise case work shows we will be below 59.3 Hz for 58.4 seconds to 42.5 seconds depending on governor action and other modeling assumptions. This is longer than the proposed 30 second limit. The final recommendation of the MRO program was to require generation protection to have a minimum of a 300 second delay for the frequency band between 59.0 Hz and 59.3 Hz (10 times the delay recommended in PRC-024), and a 45 minute delay for the band between 59.3 Hz and 59.5 Hz (270 times the delay recommended in PRC-024). Further, we recognize that programs which shed more than 30% of load will need to relax these settings and accept greater time delays. Keep in mind the MRO program was designed to work even if we get no net governor type of action as we use additional small blocks of load shed on delay to kick us towards 60 Hz if recovery is slow. We felt we got the quickest frequency recovery that was possible subject to all the other constraints we had to deal with, like limiting overfrequency and achieving relay coordination. We factored in considerable uncertainly into the design, but what may happen in the real world when everything else is going wrong can be chaotic and cannot always be anticipated. All of us in the industry really need to consider that when deciding how to set generation off-nominal frequency protection. Units can accept considerable time at frequencies closer to 60 Hz, and can generally operate continuously at +/- .5 Hz off of 60 Hz. The time delay associated with the 59.3 Hz setting proposed in PRC-024 is only 30 seconds which is way shorter than actual equipment capability (based on a reasonable accelerated loss of life per event). The system should be capable of operating at 59.3 Hz in excess of 30 minutes. In real life you would never want to set generation protection with a 30 second delay at 59.3 Hz. That is bound to cause trouble. In real life, the unexpected is going to eventually happen and our "perfect program on paper" will get a reality check. If frequency stalls out around 59.3 Hz, the actual equipment capability allows enough time for system operators to take manual actions. The proposed time delay in PRC-024 is too small to allow manual actions. Some may think that with a perfect automatic UFLS program that we can design things so this will not happen. Wrong, things can always get worse, Murphy's Law applies. We recognize that even the best UFLS program can fail in real life as everything else goes wrong out on the system. All load shedding gives us is a good chance of survival, but we can never assure ourselves it will always work as desired in the face of the unexpected. We need to constantly anticipate what can go wrong and eliminate as much of this inherent risk as we can, but we can never provide a safety net that will work for all modes of system failure. Here is a real world example of how we could stall out at some frequency such as 59.3 Hz (or any other frequency below 60 Hz for that matter). When load shedding occurs, there is a chance the system may break up further as tie lines between remote generation and load centers become over taxed and the two systems may lose synchronism (this cannot always be anticipated up front). The result is that subislands form where one is now surplus in generation and one has too much load. The island which is surplus in generation is now at risk of losing generation on overspeed (probably due to internal problems at each plant, especially thermal plants, that lead to random tripping that is nearly impossible to quantify). Once generation trips the island will plunge into a 2nd round of underfrequency. Fortunately loss of the first unit might allow the others to survive (i.e. steam valves can open back up) so the final imbalance might still be manageable. However in this instance, the region has already used up part or all of the automatic load shedding capability. With luck this island will settle out at some frequency where operators will have enough time to manually drop load to force frequency recovery before generator underfrequency protection trips. Once generation underfrequency protection trips the first unit, the system will cascade and go black. To give enough time to do manual load shedding at this higher frequencies, you need to set long time delays on the frequencies closest to 60 Hz.

Summary of Issues – Question 6:

1. The team should provide the technical justification for BES busses at 20 & 75 MVA criteria

2. The v/Hz requirement does not belong in this standard (“load shedding document”) – IEEE standards already

exist to address v/Hz.

Response: The team does not think that this should not be eliminated as a requirement (THE TEAM NEEDS TO DISCUSS THIS REQUIREMENT TO DECIDE TO KEEP OR ELIMINATE) because it cannot be properly simulated because the voltage regulator V/Hz controls are not presently included in generator exciter/voltage regulator models. This characteristic supports reliability and the majority of the commenters indicated their support for this characteristic.

20) Question 6:

In the first posting, the Characteristics of UFLS Regional Reliability Standards required that UFLS programs be designed to limit the potential for overexcitation (V/Hz) of power system equipment at all Bulk Electric System buses. Based on industry comments, the SDT has revised this requirement in the proposed continent-wide standard to apply only at generator buses and generator step-up transformer high-side buses associated with individual generating units greater than 20 MVA (gross nameplate rating) and generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) that are directly connected to the BES. The SDT believes this change better addresses the need to have UFLS programs designed to coordinate with protection that may trip generators during an underfrequency event. Do you agree with this change?

No

21) Question 6 Comments:

Please provide the technical justification for this performance criteria. We are presently unaware of any UFLS event where V/Hz tripped a unit. It also seems this only applies when frequency drops below 57.2 Hz. This is discussed further in my comprehensive discussion included in item 8.

This requirement should not be included because this is not a major concern. Assuming we want to study this, we will find this cannot be properly simulated because the voltage regulator V/Hz controls are not presently included in generator exciter/voltage regulator models that are used for stability simulation.

The volts per hertz language does not belong in this load shedding document. Voltage regulators automatically reduce voltage according to volts per hertz when in automatic mode. Industry recommendations/standards (IEEE C37.102 or IEEE C37.106, ANSI C50.13-1989, IEEE C57.12.00-2000) already exist to address volts/Hz. If voltage regulators fail, or are in manual control, then there is additional volts/Hz relaying to trip generation if needed. We believe the volts per hertz issues are already taken care of outside of this UFLS standards document. During an under frequency event, generators should be working to pull voltages down anyway.

Please see response to question 8 regarding overvoltages related to tripping load without tripping capacitors.

Summary of Issues – Question 8:

- Continent wide standard cannot provide “right” UFLS program for all areas

Response: A continent-wide standard can provide appropriate reliability requirements for most areas since most areas already have programs in the 25-30 percent of load range. A regional variance may be proposed if a regional or sub-regional UFLS program substantially exceeding this range cannot be made to comply with the continent-wide performance characteristics.

- The continent wide standard should check if the assessment steps have been completed (a “pass/fail” approach)

Response: The SDT does not disagree, but believes that requiring an assessment to show that compliance with certain measures of reliability (*i.e.*, performance characteristics) has been achieved is also necessary. The SDT does not believe that reliability can be assured if the standard is limited only to checking to see whether certain steps have been followed in conducting an UFLS assessment.

- The NERC regions have always had the organizational structure to bring all of these experts together, and I doubt the concept of having a group of Planning Coordinators will be as effective at getting the subject matter experts involved

Response: The SDT does not disagree with this comment, but cannot, under the constraints imposed by the NERC Rules of Procedure and FERC Order 693, assign any requirements to regions. The group of Planning Coordinators within a Region was found to be the next best choice.

- "real world" factors also should be considered when designing the program – studies aren't sufficient

Response: The SDT does not disagree, but questions how the effects of such real world factors as variation in governing response and controls that override governing response can be evaluated without some sort of studies.

- PRC-006 and PRC-024 are circumventing the needed analytical process and are drawing conclusions about what is appropriate before the study work is performed. These standards provide no technical justification for the proposed measures. As written, these standards will encourage smaller load shedding programs, and if that happens, the result will be that portions of the grid will have less of a safety net to rely upon when extreme events occur.

- Setting the performance characteristics before designing the programs is putting cart before the horse especially because size of the program should be a factor considered in determining any performance criteria

Response (to both comments immediately above): Clear and measurable reliability requirements need to be set somehow. This goal cannot be accomplished if the reliability requirements are continually subject to being adjusted to accommodate study results. The SDT is confident that the draft UFLS standard will be found appropriate for the vast majority of North American systems. The fact remains that almost all existing North American UFLS programs fall within the 25-30 percent of load range. Again, the SDT believes that what is behind the majority of the commenter's comments is a concern over sub-regional UFLS programs that need to be substantially more than 25 percent. A regional variance may be proposed should it be found difficult or impossible to make a substantially larger sub-regional UFLS program comply with the continent-wide performance characteristics.

- There is no requirement to assess load shedding needs – major topology changes should be considered when performing an assessment

Response: The draft standard requires the identification of islands for study. The study of such islands should reveal the load shedding needs in terms of percent of load to shed.[cag7]

- any party (utility, group, region, etc) should not be forced to shed more than the minimum called for in the Standard, but we should let them shed more load when there is an advantage to doing this

Response: The SDT agrees.

- Both voltage and frequency are highly subjective and are not really a good way to indicate if a load shedding program is going to get the job done.

Response: The SDT does not disagree that frequency performance is subject to factors that are often uncertain or variable, such as aggregate inertia, aggregate governing response, turbine power versus frequency, and the effect of load shedding on system voltage and the secondary effect of that voltage on remaining load, etc. Nonetheless, a UFLS program must be set up to operate on frequency settings, generator off-nominal frequency durations defined in terms of frequency level must be respected, and system load knows[cag8] only the voltage and frequency applied to it. It is not as if there are an assortment of other quantities to choose from in monitoring system under-frequency (and over-frequency) performance; system frequency is all there is. Moreover, the requirement to run dynamic simulations in UFLS assessments is the only means of evaluating many of these factors in a realistic manner. The definition of "get the job done" is also subjective.

- The standard is driving towards lowest common denominator - Somewhere the NERC UFLS standards drafting team also concluded that “UFLS programs can be successfully coordinated if they are designed to achieve the same system performance characteristics”. Programs which shed different amounts of load will inherently have different performance characteristics, and work over a different range of overloads. By setting frequency based performance criteria these two standards are definitely forcing things towards the lowest common denominator as the proposed “measures” can only be met by a smaller load shedding program.

Response: The SDT disagrees that the draft standard would result in least common denominator reliability. Again, the SDT has determined that the approach that is least intrusive on the flexibility to set UFLS design parameters within a region, but that addresses the need for inter-regional coordination, is to establish continent-wide performance characteristics as are now in the draft standard. The draft standard would not restrict regions from having programs larger than 25-30 percent of load because a regional variance may be proposed should such larger programs encounter difficulties in complying with the performance characteristics at the 25 percent load-generation imbalance level.

- This reliability standard writing process should not replace engineering judgment

Response: To some extent, replacing engineering judgment with set requirements is unavoidable when reliability requirements must be coordinated across a wide area. The SDT believes a balance has been achieved in the draft standard between imposing rigid continent-wide requirements versus permitting flexibility for engineering judgment within each region.

- I think it makes perfect sense to “measure” if we are fulfilling the basic aspects of load shedding obligations. The “measure” would be “have you done activities x, y, z?”. Instead we would focus on the big picture, which is to make sure we have a reasonably effective safety net in place. The “measures” could become simple pass/fail checks to see if we have covered the basics of implementing an appropriate UFLS program. I suggest that we keep it really simple. It will be easy to check on things like: 1) has an appropriate program been designed which satisfies a checklist of items that have to be considered such as coordination with generation protection, 2) has the program been implemented, 3) has the program been periodically reviewed, 4) have any changes that came about from the review processes been implemented in a timely fashion, and so forth

Response: The SDT does not disagree, but “reasonably effective” needs to be defined, what constitutes an “appropriate program” needs to be defined, what “checklist of items that have to be considered” needs to be defined, and acceptable “coordination with generation protection” needs to be defined. The SDT believes it has used clearly defined terms in the draft standard.

- R1- a group of planning coordinators is not going to be the equivalent of the type of broad based participation we have historically achieved through the NERC Regional via the existing committee structure.

Response: The SDT does not disagree, but, as noted above, is restricted from assigning requirements to regions. The standard does not prevent the group of Planning Coordinators from using the region’s standard development process to achieve broad-based participation.

- R2-stresses consistent application across the region, and I would argue that only the final analysis of the system will tell you if this makes sense. There may be subregions which have different needs. In MRO, the Canadian systems have different needs than the US portion of MRO.

Response: [R2 wording does seem to pose a difficulty here. Could we say: “…or shall design UFLS programs for consistent application across each sub-region”? Or delete[cag9], “consistent application across”?] Note: Sub-regions may well have different needs, but interconnected sub-regions may not necessarily always be their own island. They still need to consider coordination with adjacent systems. Regional variances are permitted to address the specific needs of sub-regions.

- R3- this says we need criteria on how to select islands. It strikes me as odd that we need “criteria” on how to reach a conclusion. Shouldn’t this just say that analysis shall consider possible system break up patterns that may form islands?

Response: Unfortunately, “shall consider” is not definitive enough language to measure compliance against. “…shall develop criteria…” is more definitive. The problem with selecting islands is that you need to grant the possibility that there may not be any. Thus, having some selection criteria as the requirement instead avoids this problem.

- R4-I agree that coordination with neighboring regions is required, but I do not know how to resolve differences of opinion between regions. Are we trying to reach a consensus between regions, or just trying to share information and to create a forum for discussion? Obviously where breakups cause islands that straddle different NERC regions, we need to jointly evaluate that island. Even if this coordination is only to share information, it still allows everyone to learn from each other and is going to be quite valuable.

Response: Thank you for your comment. [I still disagree with the “procedure” approach. Could we say, “The combined group of Planning Coordinators of two adjacent interconnected regions shall conduct a UFLS assessment (as in R7[cag10]) on any islands that straddle the two regions identified in R5”? And modify R3 to say, “…to select portions of the BES, including portions of adjacent interconnected regions, that may form…”?]

- R5 - Propose a wording change, I would rather say something like: “…shall identify islanding patterns that can be used as a basis for designing an UFLS program. This shall consider:” R5-is about identifying islands. I think it is the exact wording of this section that bothers me although I agree with the intent. I prefer to focus on break points that may lead to islands.

Response: Standard language needs to be very specific and clear as to what exactly is required. “…shall identify islanding patterns that can be used…” is not as definitive as “…shall identify an island(s) as a basis for…” “This shall consider:” is not as definitive as “The identified island(s) shall include:”

- R7-is about the need to do periodic assessments. I agree we need a periodic assessment of some sort. Full blown studies on the other hand are seldom required unless some inherent flaw in an existing program is identified and we need to start with a fresh look at everything. I do not agree with meeting the performance characteristics in R6. We should meet performance characteristics which are defined as a result of the load shedding study process, and not just something that is tossed out up front.

Response: The standard requires dynamic simulations to back up the required periodic UFLS assessments. The SDT has confidence that any inherent flaws in an existing program are more likely to be discovered in this manner than by any other approach. Again, reliability requirements should not continually be subject to being modified to accommodate study results.

- I think there are other ways to assess the risk of having units trip off early than just running simulations. This almost implies we have to use full stability cases as our only analytical method. Let engineers figure out how to study the problems using whatever tools, methods, and calculations they feel are appropriate.

Response: The standard requires dynamic simulations in the assessments because the reliability risk of early tripping units can be adequately assessed in this manner. The SDT is not confident that analytical methods that do not involve dynamic simulations can do this. Can the commenter be more specific about other analytical method(s) he has in mind?

- If we require some assessment of load shedding “need”, then generation which drops off early can be evaluated in terms of how it affects the “needs” assessment, or we can demonstrate how loss of such generation affects programs in a general sense.

Response: The SDT agrees. Load shedding needs should become apparent during the course of performing dynamic simulations for the assessment of island(s) identified in R5.

- R-8 shouldn’t this database/modeling type of information be compiled as part of the regional model building process? NERC regions do this type of thing today, why is this group of Planning Coordinators getting involved in this. We use the NERC regions to do our coordinating activities, so why depart from what works? I need to understand the reasoning behind this before I can comment further.

Response: At this point, UFLS data is not required to be included in regional and ERAG / MMWG model building. UFLS data is for a highly specialized field of study distinct from the general dynamic simulation data collected under MOD-012.

- R-9 appears to say that everyone shall trip load in accordance with the UFLS program. I agree with the intent.

Response: Did you mean R10?

22) Question 8 Comments:

1.0 Introduction

After reviewing PRC-006 and PRC-024, I have to conclude that both are unsound. The general approach of trying to define a performance envelope up front before tradeoffs can be evaluated in the design work is going to be a problem. These standards really do not encourage the right thing, which is to ensure we have the right UFLS program in place to meet the needs of a given area. The "measures" are inherently subjective, and really do not measure if we have created the right "safety net". I go into considerable detail to explain my concerns, but basically in the design phase we need to make compromises between mutually exclusive objectives. Therefore we need to stay away from trying to micromanage the design process at the Standards level. Tradeoffs affecting performance will always be involved and I do not think the standard needs to get involved in exactly how we reach a conclusion about what needs to be done. I think the standard should just focus on making sure we put the plans into effect, and that we implement the load shedding program. We should leave all of the performance issues to a work group that does the actual design and analysis. This is basically operating study type of work to create a remedial action scheme which responds to abnormal system conditions. My conclusion is that we need a different type of "measure" for the UFLS standard and that the generation off-nominal frequency protection related criteria in PRC-024 should be eliminated completely and that it should not be part of any NERC standard. PRC-024 is trying to make the compromise about what is an acceptable tradeoff for setting generation off-nominal frequency protection before the required study work is even started. It makes more sense to have a "measure" for UFLS which focuses on fulfilling the various activities such as design, implementation, and review, as the end result is what is important to ensure reliability. I envision this would be more of a pass/fail, have you performed these activities or not, type of assessment. I know this is a controversial statement, but I believe the following discussion will explain how I arrived at this conclusion.

1.1 My UFLS background

Before I comment on technical issues, I would like to provide background information. This is to explain why I hold such strong opinions on the subject of UFLS, and to show my involvement and commitment to developing appropriate regional UFLS programs. I hope this gives some credibility to my statements. I have a unique "hands on" work experience. This gives me considerable insight into this subject and a different perspective. I have about 20 years of experience with UFLS issues, have dug deep into the subject, have read all the technical materials I could find, and so forth. I spent several man years on this subject although my primary job function involves power system analysis, mostly operating studies (power flow and stability studies and so forth). My initial involvement in UFLS was an offshoot of disturbance analysis. This involvement with UFLS expanded into the area of assessing regional needs and in doing the technical work to develop a new UFLS program from the ground up which better fit the needs of different geographic regions. This was the big picture type of work with lots of things to consider. My background which is relevant to this area of investigation includes:

* 29 years of experience doing system studies (power flow, transient stability, operating study work, modeling issues, disturbance analysis, etc.)

* From 1987 to 1990 worked almost full time on the Colorado/Wyoming Off-Nominal Frequency Program design and study report (a regional load shedding and generation off-nominal frequency protection coordination effort tailored to the needs of the area, and which coordinated the needs to two islands, one a subset of the other). I was chairman of one of two technical work groups created by the executive committee, and did a significant amount of the analytical work and report writing.

* 1996-1997, I worked on the WSCC UFLS program design and study report as one of five authors. This program is presently the WECC program and was strongly influenced by how the Colorado/Wyoming program was developed.

* 2001, I performed a review of the MAPP UFLS program on behalf of MAPP, and concluded that MAPP needed to develop a new UFLS program to address overfrequency and generation off-nominal frequency protection concerns.

* 2006-2007, I was chairman of the MRO UFLS Task Force which designed a new UFLS program and generation off-nominal frequency protection requirement for MRO. This was basically the follow up to the MAPP work that stalled out in 2001. Implementation has been put on hold until the NERC UFLS standards writing process has concluded.

* I have had the benefit of collaborating with many other engineers, of varied backgrounds, on the subject of UFLS. I have been exposed to many different aspects of the problem and to different viewpoints. My perspective is based on information I have gathered as it pertains to system planning and operation, relaying, control area type of issues, power plant issues, and so forth.

I was once told that "sometimes things seem simple only because we don't usually have the time to learn the complexities". This is certainly true of UFLS issues. This standards drafting process has led to certain initial conclusions that set the direction of how the UFLS standard is being drafted. I have to point out that things are not nearly as simple as they may appear at first glance, and we are jumping to the wrong conclusions, and that is steering this process in the wrong direction. In order to best explain my concerns with how this UFLS standard is being written, I need to cover some of the basics to provide a context.

1.2 The big picture: what are we trying to accomplish by shedding load?

The simple answer is we want to use load shedding as a safety net. The objective is to prevent a blackout following an islanding event that creates an imbalance between load and generation. We want the program to force quick frequency recovery so that we can better coordinate with generation off-nominal frequency needs. We want to make sure that our program has no fatal flaws that are going to make things worse, and hopefully we can try to make this program as robust and foolproof as possible.

1.3 Who should design UFLS?

The design details need to be resolved through a technical study process involving individuals with the skills to do this type of analysis, or who are willing to spend considerable time to learn the skills. Historically this has been accomplished by forming appropriate study groups. Such groups usually include individuals with varied backgrounds which may be relevant to dealing with the different aspects of off-nominal frequency issues. The NERC regions have always had the organizational structure to bring all of these experts together, and I doubt the concept of having a group of Planning Coordinators will be as effective at getting the subject matter experts involved.

1.4 Analytical approaches and modeling limitations

First of all, there is no perfect tool for studying load shedding and performance is highly subjective. The question is, what performance, and for what conditions and assumptions? We have to keep this in mind before jumping to conclusions about what kind of performance characteristic we can meet.

Trying to establish the UFLS performance characteristic up front and then designing the rest of the UFLS program afterwards is equivalent to saying we know what our protection needs are and what the resulting system performance is going to look like before we do any kind of analysis at all. This is unrealistic. The one factor which is the most significant is the size of the UFLS program. Larger programs have inherently different performance characteristics than small programs. More compromises have to be accepted to make larger programs work. NERC Regions typically set a minimum criteria for load shedding, but higher levels are sometimes needed and are typically allowed. The amount of load presently being shed in different areas varies from about 25% to 60% or more.

Modeling must involve some form of dynamic simulation which captures the salient features. Underfrequency relay application guides suggest use of a simple equivalent inertia model which captures frequency decay dynamics. I have found this approach extremely useful and insightful. This approach is good for rapid prototyping and generalizing trends, evaluating performance over a range of overloads, evaluating sensitivities, etc. The weakness of this approach is it does not include effects of voltage changes and usually ignores governor action (in MRO UFLS work, we added a governor model as part of the sensitivity work, but designed the program to work even if we get no net governor type of response to an underfrequency event). The “Equivalent Inertia” approach is essentially use of a one bus stability case with voltage held at unity, which models the inertial response of a full system.

Full stability cases are more useful for looking at a very specific scenario (one overload level, a historical event, etc.). Stability cases are also useful in addressing voltage transients and identifying possible system break points. The usefulness of a full stability case for the study of load shedding is often overestimated. In reality, too much detail is not always helpful in sorting out the general trends. Stability cases give a very specific answer but can fail to give the needed insight about how things work “in general” and it can take significant time to modify cases so they are useful for this type of analysis. The level of modeling needed for typical transient stability studies is somewhat different than what might be needed for a load shedding study, so do not expect that stability cases will have all of the modeling details needed for load shedding studies.

The user has to be aware of what each dynamic modeling approach represents, and what the modeling limitations are. Even full stability cases do not model some of the processes which have an effect on a load shedding event and consequently results have to be carefully interpreted (for example, stability cases do not model generating plant boiler dynamics and emergency overspeed controls which protect for full load rejection, but which operate on large partial overloads). The way islands are created in the simulation can affect results. For instance, opening all lines at the same instant to form an island is a typical modeling approach that has nothing to do with how islands really form. This approach to creating an island will affect the final result to some extent, but we generally have no better option.

We also need to stop once and a while and consider the real world issues to try and make things as fail safe as possible. There is more to UFLS design than just running studies.

The point is that study work results are inherently approximate, and much more subjective than most realize. Simulations need to be interpreted with a good deal of common sense and a good understanding of system dynamics, and a clear idea of what all the qualifying simulation assumptions are. Hopefully this standard will stay away from prescribing any particular modeling or analytical approach. Let planners use the engineering tools they have as they see fit, and let them decide on the tradeoffs we have to accept to make this work.

1.5 UFLS design work, conflicting requirements, and uncertainty

UFLS program design and performance details can only be worked out through a systematic study work process that considers all of the relevant details, the conflicting requirements, and as much of the inherent uncertainty involved as is possible to consider. Despite the complexity, I believe we can design a good UFLS program for a given region if we are systematic and try to deal with all the issues as best as possible by applying good engineering methods and good judgment. Once we lay out all the details, we have an optimization problem, and have to consider the options available and the tradeoffs. Some of the final program details will probably end up being decided according to a judgment call. However, I do not believe that we can set performance standards first and then expect the engineers to magically make this work. Almost everything to do with UFLS has to be based upon study work and must have a solid technical justification.

The design goal is to develop an UFLS program which has a high probability of preventing system collapse following an islanding event. This sounds simple so far, but a little investigation will show the problem we are trying to deal with is complex and poorly defined. We are guessing at what might happen and are trying to hedge our bets in the face of considerable uncertainty. The deeper the investigation goes, the more we become aware of the conflicting requirements. For instance, the things we need to do to limit the minimum frequency, to limit the maximum frequency, to ensure good relay coordination, and to maximize the size of the UFLS program all conflict with each other…to solve one problem we impact a different objective.

Many factors which affect real world performance are outside of the control of the parties doing load shedding. These factors are: dynamic characteristics of load, system energy stored in rotating generation via the flywheel effect (this is the inertia, and it relates to dispatch), units which are unresponsive to governor action, boiler dynamics, power-load controllers which can over power governors and force units back to the original schedule, gas turbines which inherently drop power as frequency drops, wind generation which essentially provides no inertia and is highly unpredictable, unexpected random events, etc. To complicate the analysis, different parts of North America will have to address factors that are unique to their own local areas.

We want to keep "real world" complications in mind as we do our studies, and it is even reasonable to anticipate what system operators will have to do next if load shedding fails to work as desired. Historical events show this happens, and if we are lucky frequencies will stall out close enough to 60 Hz that operator action can be initiated to restore frequency (this has implications concerning why it is a really bad idea to set generation protection time delays too short for frequencies between 59 Hz and 61 Hz).

Also consider that we are just making educated guesses about what islands may form in real life. Some islands are easy to identify and predictable, but that is not always the case. Major breakups seem to occur following a sequence of events which are far beyond anything covered by typical criteria, and these events are usually nothing we would have ever dreamed up. Often the final island is not what we anticipated.

At this point let's assume we know what our island should be, what the maximum overload for this island will be, and that we have some idea of general performance objectives. As we go into study mode we find that many of the factors which affect results are difficult to pin down. This includes the assumptions used for load damping, governor response, and the energy stored in rotating units (the inertia). The term "typical data" reflects a rather wide range of these parameters. In developing the MRO program we dealt with this uncertainty by using the simplified equivalent inertia model and then varying all of these parameters over a fairly wide range as we also considered a range of potential overloads. This is much more than is typically done, and this type of sensitivity analysis would have been extremely difficult, if not impossible, to perform with a full stability case.

In the design phase we want to work though all of the interrelated issues, such as achieving coordination with generation off-nominal frequency protection. To do this right, we have to design a load shedding program which gives the best frequency recovery (subject to all the other constraints), and then see how much time is spent below 60 Hz in various frequency bands so that we can propose generation protection settings with delays with some margin over our worst case frequency recovery times. We also need to know something about actual generation off-nominal frequency capabilities to further judge the appropriateness of the suggested protection settings.

We want to make sure this safety net is well designed and that it has no obvious flaws. Preferably, we want to anticipate what could go wrong so that we can try to avoid as many problems as possible and alter the design accordingly. Then work has to iterate towards a best compromise solution.

2.0 Critique of PRC-006

Although the intent of this write up is to discuss PRC-006, I also have to discuss PRC-024 in some detail since both standards go hand in hand. Load shedding and generation protection are interrelated. Both parts have to be addressed together in any discussion of UFLS issues. It is unfortunate the standards drafting teams broke things down into two different standards like this. Generation off-nominal frequency protection is inherently part of UFLS programs, and has to be assessed in this context.

2.1 UFLS standards need to be technically sound.

I empathize with the standards drafting team and know the difficulty of their task better than most. However, I am not satisfied with the NERC UFLS standard PRC-006 or the generation protection settings suggested in PRC-024. I find this new PRC-006 UFLS standard and the companion PRC-024 generator off-nominal frequency standard to be unsound. These standards are circumventing the needed analytical process and are drawing conclusions about what is appropriate before the study work is performed. These standards provide no technical justification for the proposed measures. As written, these standards will encourage smaller load shedding programs, and if that happens, the result will be that portions of the grid will have less of a safety net to rely upon when extreme events occur.

2.2 There is no requirement to assess load shedding needs

My observation is that a minimum load shedding requirement of 25% to 30% of system load will serve the needs of most of the system. That is my personal judgment, based on previous study work experience. I also know we can design fairly well behaved programs which shed 30% of load, and my personal bias is to shed more than to shed less. However the 25% load shedding used in the East was based on the same type of analytical process as I would go through, and they felt this level was a better fit for the tradeoffs involved. UFLS design involves these types of judgment calls. However, it seems odd that this standard does not require any kind of assessment to define the size of the imbalance we may have to deal with. This means we are not requiring anyone to know their actual load shedding needs. Perhaps that is implied by having "groups" do the UFLS study work. The load shedding needs are the first thing I would want to know, and to get at this information we have to evaluate possible system breakup patterns and possible load and generation scenarios to see what the imbalance might be. The purpose of such a review would be to see how much coverage the 25% load shedding requirement gives, and to estimate what might be a more appropriate load shedding target level. This type of analysis does not have to be perfect; we just need to know general magnitudes and make sure the involved parties feel their own needs are being satisfied. I use the phrase "target level" in the sense that once study work is performed we may have to consider a different size load shedding program to achieve over all coordination requirements. Everything is a series of tradeoffs. If we set performance criteria too tight, we could easily find that all we have left to work with to meet the criteria is to put in a smaller program, and then we will only meet criteria over this smaller range of coverage.

2.3 Higher load shedding levels should be encouraged if it makes sense

While we do not believe that any party (utility, group, region, etc) should be forced to shed more than the minimum called for in the Standard, we believe we should let them shed more load when there is an advantage to doing this. This will be the exception, but some areas, such as parts of Canada, are obviously prone to islanding and these areas often have high load shedding needs. Some areas shed 60% of system load, or perhaps more. Historically, UFLS standards have been minimum standards which tell utilities they must shed at least a certain amount of load. Regional programs allowed or even encouraged utilities to shed more load when it made sense. It seems obvious that this intent is still there, but the problem is that the "measures" chosen for this standard actually discourage this.

2.4 Frequency is subjective, and should not be a "compliance measure"

PRC-006 uses frequency and voltage as "measures" to ensure UFLS programs satisfy reliability objectives. I believe these are both inappropriate "measures". Both voltage and frequency are highly subjective and are not really a good way to indicate if a load shedding program is going to get the job done.

Let's review the basics: 1) frequency drops following loss of generation or import with an initial rate of change of frequency defined by the size of the overload and the system inertia, 2) since turbine power can generally be assumed to be constant, this frequency drop increases generator torque as torque=power/speed, 3) load torque drops according to the load damping characteristic, and 4) we eventually reach equilibrium at a new lower frequency where once again Generation = Load at the new synchronous frequency. (A footnote: turbine power is not always constant during a frequency decline, combustion turbines have thermal limits requiring the power output to be lowered as frequency drops, causing a further drop in system frequency. Governor response on these units will only be momentary before thermal controls take over.)

Now let's consider how these variables affect our performance "measures". For a given overload, final frequency is a direct function of the load dynamic characteristics which are not precisely known. We know the damping constant used in models is in the range of 1 to 2, and anything in that range is "typical". Low damping will give the lowest frequency and highest frequency deviations. The equivalent system based inertia H = sum of MW-sec of online units/total Pgen, is a function of different unit dispatch scenarios. For a given overload, high inertia gives slower rates of frequency change, better relay coordination, a higher minimum frequency, and slower frequency recovery. Small inertia gives high rates of frequency change, lower minimum frequencies, relay coordination problems and possible overshedding.

With the wide range of "valid assumptions" to choose from, folks can essentially pick the off-nominal frequency results they want to show for compliance purposes, and if results of a large program don't look good enough, they can switch to a smaller program so that it satisfies the "measure". Choosing modeling assumptions is not "gaming", it is standard engineering practice, but a single set of assumptions does not tell the full story. I would rather have measures which encourage folks to look for potential problems instead of measures which punish them for finding such problems. I would also like to see the measures encourage larger UFLS programs when that meets some identified need.

To further complicate matters; let's compare a large UFLS program (sheds 45% to 60% or so) with a small program (sheds 25% of load). Let's assume they both have 5 stages of load shedding. Over the range covered by the small program, it will work in a more refined manner than the larger program as it uses smaller load blocks. For overloads between the sizes of the two programs, only the larger program will work. So how should performance be judged?

There is a reason I chose the same number of load shedding blocks in this example, and it is worth digressing for a moment to explain. As a practical matter, UFLS programs can only make use of 5 or 6 high speed load shedding blocks while still achieving good relay coordination and while also keeping the minimum frequency from dropping too low. This is not a hard and fast rule, but it is what I have seen in my study work. This is an effect related to inherent time delays introduced by relaying detection times and breaker operating times, and the frequency spacing needed between relays to achieve relay coordination. Of course if we are willing to toss out relay coordination we can improve the underfrequency response at the expense of creating overfrequency problems which then have to be hammered back by automatic load restoration or the equivalent (for instance, Manitoba Hydro can drop power coming in on DC lines to balance load with generation but that is a very unique situation).

2.5 Voltage is subjective, and should not be a “compliance measure”

Overall, I am more concerned with the magnitude of the voltage out at the load rather than volts/Hz issues at the generator. The volts/Hz issues are already well covered by IEEE/ANSI standards, and this is difficult to model since exciter/voltage regulator models typically do not include a volts/Hz function, so the automatic reduction of the generator terminal voltage which occurs in real life does not show up in simulations. During load shedding the generators will be pulling the voltage down anyway. My understanding is that volts/Hz issues are less restrictive than other underfrequency concerns/factors. This would be something we need to look at if we allow frequencies to drop to 57 Hz or less. (Unit terminal voltage is controlled by the voltage regulator and outside of the transient time frame, we can assume the steady state voltage will be limited to 1.05 pu to .95 pu, so 1.10 v/Hz gives problems in the range of 60*1.05/1.1=57.27 Hz to 60*.95/1.1=51.8 Hz.) In addition, units are only at risk if this voltage regulator function fails, or if units are in manual voltage control. In that case the backup volts/Hz relaying will trip a unit. I am not too worried about voltage regulators failing and do not consider volts/Hz as a major risk factor. Usually volts/Hz is not given too much attention when designing UFLS programs. I am not aware of any of the existing UFLS standards having any volts/Hz criteria, but perhaps I am mistaken. I suggest the volts/Hz requirement be removed from PRC-006 because it really does not add anything which is not already covered elsewhere.

2.6 Overvoltage as a source of additional uncertainty

As load is shed we can get overvoltages out at the load which effectively increases system load. To some extent this voltage related load increase offsets the benefit of load shedding. Voltage control issues during load shedding/system break up are extremely difficult to assess. Voltage changes are a function of changes to VAR supply/consumption, as well as inversely proportional to system strength (i.e. fault MVA magnitude). System breakups and associated loss of generation can weaken the system and make voltage control much more difficult to manage. There is a general recognition that some capacitors need to be shed with load, but such details have to be worked out and refined at the local utility level as part of the load shedding implementation phase. I do not have a good idea of what is “the best that we can do”. I imagine it will vary with disturbance. I am not sure how this should be handled in the standards drafting process. I want to create an awareness of the problem so that folks give this some attention, and apply good common sense, but I do not want to turn this into any kind of “measure”. This is more of a bottom up type of analysis where very specific local detail has to be considered, where the rest of the UFLS conceptual work is the top down, big picture stuff where we do not need to address such specific local details. I am confident that utilities will do the right thing once set on the right course, and these types of details can be reviewed in the subsequent periodic UFLS assessments and things tweaked if needed. I just don’t know how to make this process any better than this. We have to be careful that we do not try to micromanage this difficult task.

The MRO UFLS effort tried to anticipate as much complication as possible, but we could not cover all of the inherent uncertainty involved. No one could. The main source of uncertainty we could not deal with is how potential overvoltage’s may increase load and decrease the effectiveness of the load shedding program. This gave us additional justification for using a "no net governor response" scenario for evaluating coordination between load shedding and generator protection (this voltage uncertainty is not the only reason for using a no governor assumption: basically units that are base loaded cannot respond to underfrequency, power/load controllers may override governor action after a short time delay, combustion turbine thermal limits will quickly override their governor action with power dropping off faster than the frequency decline, wind generation may drop off and would not have a governor anyway, and so forth; the bottom line is that we do not know what level of net governor type of action we can count on, and what little we get may be offset by increases in voltage).

2.7 PRC-006 and PRC-024 are forcing UFLS programs to the least common denominator

PRC-024 and PRC-006 both fail to satisfy a comment made in the NERC UFLS unofficial comment form which indicates the UFLS standard is supposed to provide an appropriate level of reliability, not the least common denominator. Somewhere the NERC UFLS standards drafting team also concluded that "UFLS programs can be successfully coordinated if they are designed to achieve the same system performance characteristics". Programs which shed different amounts of load will inherently have different performance characteristics, and work over a different range of overloads. By setting frequency based performance criteria these two standards are definitely forcing things towards the lowest common denominator as the proposed "measures" can only be met by a smaller load shedding program. The PRC-006 UFLS standard and companion PRC-024 establish tightly defined performance characteristics which at best will just barely work for a 30% load shedding level. Perhaps I should be more careful and say it works for a 30% load shedding level for a range of assumptions, but not for all of the conditions/modeling assumptions that we looked at in the MRO study. Those settings certainly do not encourage a robust UFLS program.

This "one size fits all performance envelope" approach only works if we use the worst case (largest UFLS program) as a basis for the performance envelope. We can characterize these larger load shedding programs as having to accept more tradeoffs. The minimum frequency will be lower, the maximum frequency will be higher, larger load blocks will have to be shed making things more drastic, and the programs are likely to be more susceptible to relay coordination problems (due to the high rates of frequency decline associated with the large imbalances). What you get for these tradeoffs is a bigger safety net.

The generation coordination part of UFLS analysis should be addressed directly in PRC-006 as something that needs attention, but the specific details such as those presented in PRC-024 need to be worked out at the UFLS working group level in coordination with the study process that designs the load shedding program. This type of information is not appropriate for NERC standards. The off-nominal frequency limits in PRC-024 should never have been created and should be eliminated. PRC-024 is poorly thought out and is going to do much more harm than good.

Setting generation protection up front before casework is run is putting the cart before the horse. This is an attempt to micromanage the UFLS analytical process without having a full view of the big picture. It just represents someone's judgment call concerning what is appropriate. It does not accurately reflect generation capabilities and no technical basis was provided to justify the "measures" in the standard. In my opinion PRC-024 is seriously flawed and actually is a serious threat to reliability. It also conflicts with the new MRO UFLS program we developed, and if other regions did the type of analysis that we did, they would probably find this causes problems for them as well. (Most UFLS programs do not go to as great of lengths as we did to look for potential problems over the full range of overloads covered by the program.)

I am well aware of generation off-nominal frequency issues and concerns, I have had my eye on this for 20 years. In the MRO UFLS study we did all that we could to minimize the off-nominal frequency exposure to generation, even going to the point of designing the load shedding program as the first line of defense for generation. This is achieved by designing the UFLS program to force quick frequency recovery even if we get no net governor action. This is achieved by having small blocks of load shed on delay that only trip if frequency recovery is sluggish. The point to make here is that the PRC-024 standards drafting group is not the appropriate group to be deciding on what tradeoffs are appropriate for coordinating load shedding with generation protection requirements, and they are ignoring some important "real world" consequences. Some of what is in PRC-024, if implemented, would be catastrophic for the grid.

2.8 Overfrequency issues

The diagram from PRC-024-1 suggests that overfrequency tripping of generation is going to be allowed in similar fashion to how underfrequency tripping of generation is applied. Extreme caution is needed. If we add relays to instantly trip generation according to the overfrequency part of PRC-024, we will have multiple units tripping at the same time and we will cause a blackout. I would call this a really big fatal flaw.

Units self protect on overspeed and we do not have to add additional overfrequency tripping relays unless this is a planned activity used to balance load and generation.

It is important to have some understanding of overspeed issues and related controls, so I need to take a moment to cover this subject. In addition to the normal speed regulating governor, all power plants already have internal emergency overspeed controls to deal with full load rejection (loss of all lines out of the plant with turbine running flat out). These controls also activate on partial load rejections (overfrequency during islanding). These controls can have many names: emergency or preemergency governor, overspeed controls, load rejection controls, trip anticipators, or something similar. We do not want to be modifying these controls and their settings, but we need to understand how they operate. These controls vary at each plant so the following discussion has to use generalities to make my point. I am most familiar with controls on steam plants so this discussion applies to that type of generation. Generally these emergency overspeed controls try to limit peak speed to something below 110% by closing all turbine valves, and if this fails, the unit is tripped to prevent mechanical damage. To limit peak speed, these controls have to start closing valves as units start to accelerate. These controls are applied a little differently at every plant, but have to act before things get out of control, so they generally activate between 61.2 Hz to 61.4 Hz on low inertia units (in this instance I am talking of the inertia constant in dynamics, H=MW-sec/Mbase of machine), and sometimes not until 62 Hz if unit inertia is high. These emergency overspeed controls are in addition to the normal governor, and are much more drastic and just slam all steam valves shut. These emergency overspeed controls are not modeled in stability cases and I bet that most planning engineers have never given them much thought. It seems we never see frequencies any higher than about 61.4 Hz following a breakup, while stability cases might indicate frequency should have gone much higher. These would be the controls responsible for that disconnect between the real world and the simulation world.

Outside of the inherent factory installed overspeed controls, we have to exercise great care and caution when applying additional relays to trip generation on overspeed. The purpose of such tripping would be to restore the balance between load and generation within an island. If this is done, we need to be aware of the risk involved. Because these load rejection controls slam valves shut, the system frequency is unlikely to get much higher than 61.4 Hz (for a system which is primarily coal fired) no matter how large the initial imbalance. (Most steam units that I have looked at activate around 61.2 Hz to 61.4 Hz, and at one time I looked at every unit in Colorado and Wyoming to get a feel for what is typical.) Once these controls activate, frequency is no longer a measure of the imbalance between load and generation. We cannot keep steam valves closed for too long, constraining all the steam with the boiler going full tilt, or else random unit trips will start to occur due to any number of internal plant problems. We do not know how much time we have to get valves back open before we are at risk of losing a unit. Someone estimated 15 seconds (I can’t say if this is right or wrong, but it sounds about right to me), and then internal plant problems will start to occur. Often we see that one plant trips first and this helps. That reduction in generation rebalances things for other units allowing steam valves to reopen. The random nature of what happens in response to overfrequency complicates any planned unit tripping actions to correct the imbalance. If the sum of planned and unplanned tripping is too much, we cycle into another underfrequency event. This illustrates why dedicated unit tripping on overspeed has to be considered carefully, and should only be applied as a method to rebalance load and generation, and not as overfrequency protection of the type we apply for underfrequency. If generation is tripped to correct overspeed in an island, it has to be done in small increments (equivalent to about 1 to 1.5 % of remaining load) and trip times have to be staggered. For the purpose of balancing generation with load, unit tripping should only be implemented on a few selected small units. The trip setting would have to set at frequencies no higher than something like 61Hz to 61.4 Hz, or else these relays may never pick up. Picking the right delay times is tricky and would have to be based on simulation results. In practice, it may make more sense to do automatic load restoration to rebalance. This is something that has to be studied on a case-by-case basis.

As a side note: in the MRO UFLS effort completed in 2007, we were very concerned about overfrequency. This led to changes from the MAPP program of shedding 3 blocks of 10% to a program shedding 5 blocks of 6% . We then focused on adding adequate spacing between relay settings to reduce the risk of overshedding under our worst case assumptions of large overload, low inertia, and low load damping. The compromise was we had to accept lower minimum frequencies.

2.9 We need realistic minimum frequency limits on generation that meet load shedding needs

I also have concerns with the chosen minimum frequency in PRC-024, and the time delays proposed at different frequencies.

Although the MRO UFLS Taskforce expects that under "typical conditions" that minimum frequency will be above 58 Hz, (for loss of generation/import of up to 30% of system load in the island), our worst case simulations indicate we could briefly dip below that, and we used our worst case results to set generation protection frequency settings and delays. In addition, our "equivalent inertia" modeling approach ignores machine to machine oscillations which might cause frequency at different locations to differ by .2 Hz or so as the system frequency rings down. For this reason, we chose 57.6 Hz as the point where instant tripping of generation is allowed. This is below our worst-case minimum frequency of 57.77 Hz (for a very low inertia, low damping, no governor scenario that is perhaps overly pessimistic). This instant trip setting for generation can also be justified in another way. Our design criteria set a target where we wanted the minimum average system frequency >= 58 Hz, and we seem to meet this for most conditions. This 58 Hz minimum frequency seen in our models then has to be adjusted by about - .2 Hz to account for machine to machine oscillations seen in the real system and not in our model, plus about .2 Hz margin to ensure good relay coordination. This takes us back to 57.6 Hz as the appropriate frequency for the instant trip setting on generator off-nominal frequency protection. Programs which shed more than 30% of load will need to relax generation protection and accept lower frequencies and longer time delays.

2.10 An example of coordination between load shedding and generation protection as performed in MRO UFLS study

In order to come up with the MRO generation protection settings we monitored time spent in frequency bands spaced .1 Hz apart and we consider the performance over the full range of coverage (0 to 30 % loss of generation) and considered a wide range of assumptions concerning system based inertia (H system base = total MW-sec stored in rotating mass divided by P gen) and a range of damping, in addition to a possible range of governor actions. We optimized the program to minimize time spent below 60 Hz while addressing all the other constraints we had to deal with. Once we knew the expected worst case times in each .1 Hz band below 60 Hz for the optimized program, we came up with the stair step type of generation frequency versus time delay settings that gave a reasonable fit to the expected worst-case time versus frequency information (plus some margin) with the fewest frequency bands. To fully understand what we did you will have to refer to the MRO UFLS report on the MRO website. The short version is that we ran 1000's of cases to arrive at our conclusions. What we came up with for generator underfrequency protection minimum time delays is what we need to ensure the load shedding has time to play out to restore frequency and to give some margin to ensure relay coordination. If we shorten the generation protection time delays and raise the frequency setting for the instant trip point, then there is a narrower range of conditions for which the UFLS program would be expected to work as intended. Our safety net becomes less robust, we make things less secure.

2.11 Load shedding can be used as the first line of defense when it comes to generation underfrequency protection

The MRO load shedding program is designed to be the first line of protection for the generators because it is designed to force frequency recovery even in the absence of governor action by having small blocks of load shed on delay to quickly bring us back towards 60 Hz when recovery is too slow.

2.12 Generation off-nominal frequency protection settings imply more risk than units may experience

Although there is a chance that frequency may be slow to recover as a worst case, most of the time it will recover much faster than the times we used for generation tripping coordination. The expected time spent below 60 Hz sort of takes on the form of a probability density function. This type of information gives a better idea of what units may be exposed to, and the real risk is less than what the generation protection settings may imply. Therefore, our approach was to coordinate generation off-nominal frequency protection to match the worst case frequency recovery times seen in our simulations after first doing everything possible to minimize underfrequency exposure to generators when designing the load shedding program. For the MRO region, the recommendations of the MRO UFLS report should take precedence over what is being proposed in PRC-024 and PRC-006.

2.13 UFLS programs which shed higher levels of load need less restrictive generation off-nominal frequency protection

In MRO, we recognize that the Canadian portion of MRO needs to shed more than 30% of connected load. The MRO UFLS report indicates that any program that needs to shed more than 30% of load will need to relax the MRO generator off nominal frequency time delay settings for generation and accept longer delays and lower minimum frequencies. This is an engineering reality. The Off-Nominal Frequency Capability Curve from PRC-024 does not give this kind of flexibility. Alternately, some improvement on minimum frequency can be realized by designing a program that oversheds but then the program will be prone to overspeed problems. This approach can get scary. Some improvement in coordinating with generation needs can be achieved by designing the UFLS program to start shedding at higher frequencies. This gives a corresponding improvement to the minimum frequency but this action often creates coordination problems with neighboring programs. On the other hand, sometimes you want one area to start shedding first to meet some specific objective. This is just another example of how every single facet of UFLS program design has to be carefully considered. In many ways, this is no different from any other type of planning or operating study work.

The bottom line is that this reliability standard writing process should not replace engineering judgment. Utilities need flexibility so they can make the necessary compromises after all things are considered. Making adjustments to generation protection frequency settings and associated time delays is most likely the best approach to ensure coordination with larger load shedding programs. We must give sufficient time for load shedding to act even if it means we need to accept some additional potential loss of life to generation for some hypothetical underfrequency event. I believe this is prudent and will not place undue burden on generation.

2.14 The starting frequency of load shedding programs

In MRO we would have considered an UFLS program which starts to shed load at frequencies above 59.3 Hz (probably 59.5 Hz) if neighboring regions would have shown interest in doing the same. However that was not the case. All the programs in the region started at 59.3 Hz so we stuck with that. If we had increased the starting point to 59.5 Hz, we might have increased the risk of dropping load on power system swings where no load dropping is needed (if so, this would probably be isolated to a few buses), but we would have improve the minimum frequency and this helps larger load shedding programs meet coordination needs.

2.15 Turbine/Generator underfrequency capabilities

To talk about off-nominal frequency capabilities of turbine/ generators, I will once again have to generalize a bit. The continuous operating range for no accelerated loss of life is typically 60.5 Hz to 59.5 Hz. The frequency which requires an instant trip, for most generation (I will ignore combustion turbines for now), is below 57 Hz for steam, and as low as 56 Hz or lower for hydro. Steam turbines are more restrictive than hydro because of blade resonance issues and the result is that the time versus frequency limits are logarithmic with considerable operating time allowed just below 59.5 Hz and very little operating time is allowed at the lower frequencies. Limits are generally based on a theoretical “probable loss of life” after being subjected to some total time spent below 60 Hz over the life of the plant. This also fails to take into consideration that units get maintained and some issues are corrected before becoming problems. So we have to evaluate what fraction of this theoretical off-nominal frequency based accelerated loss of life needs to be used to respond to a rare and infrequent islanding event, but in the end this is a judgment call and is driven by what we have to accept to get the job done. Limits for combustion turbines seem to vary, with instant tripping suggested anywhere from about 57 Hz to 58.2 Hz. I know less about these than I do about other types of generation, but we learned what we could about these during the MRO UFLS study process. The group that did the last WECC UFLS review got quite involved in this area of investigation, and the MRO group benefited by consulting with the former chairman of that group. 20 years ago the combustion turbines were not showing up as a limiting factor, or we failed to notice the issues. I personally question the basis for the 58.2 Hz instant tripping point that is recommended for one make and model. It is hard for me to imagine that a very brief dip below 58.2 Hz is going to be a problem when considerable operating time above 58.2 Hz is allowed. This low “instant trip” frequency setting is out of line with historical industry practices and our industry has to encourage manufacturers to build equipment with better off-nominal frequency capability than this.

2.16 Don’t get too conservative with Generation off-nominal frequency protection settings

I feel that many times utilities try to get too conservative in how they want to set generation-off nominal frequency protection to the point where this may affect UFLS. If we set this too tight we might end up with a blackout. Black start plans are where the real off-nominal frequency loss of life can be chewed up. Generally such plans call for this protection to be disabled so that it does not interfere with restoring the system.

Another issue that I have heard several times as justification for using very conservative generator off-nominal frequency limits is that some folks are claiming their insurance sets underfrequency limits for their generation. Who is to say if the terms of the insurance coverage even makes any technical sense? This hardly sounds like a legitimate reliability issue. From my perspective, this seems at odds with system reliability. I also expect that independent power producers will not be as interested as a traditional vertically integrated utility would be in trying to prevent the grid from collapsing. I expect that at least some of them would just as soon shut down as quickly as possible instead of riding the disturbance out. We have to ensure they do not do this or it may have catastrophic consequences.

2.17 Short time delays being proposed for generation protection at frequencies close to 60 Hz is a huge risk to the grid, (i.e. at 59.3 Hz, 60.7 Hz)

We need to allow much more operating time at the frequencies closer to 60 Hz than what the NERC standards drafting teams are proposing in PRC-006 and PRC-024. The proposed time delay limit says we can only operate at or below 59.3 Hz or at or above 60.7 Hz for 30 seconds. This is completely unrealistic and a huge threat to system reliability because these standards are essentially giving generation permission to set protection relays accordingly. Remember that once generation starts to trip on underfrequency it can quickly cascade into a blackout. This entire subject of what is appropriate for generation off-nominal frequency protection is something for the experts in study groups to work out, and should not be addressed in either of these standards.

At frequencies close to 60 Hz the appropriate generation protection time delays need to be on the order of 30 minutes or longer instead of 30 seconds as proposed by PRC-006 and PRC-024.

The analysis we did in MRO indicates there is a chance that we will take longer than 30 seconds to get above 59.3 Hz even if our UFLS program works as planned. Remember we did this “bandwidth” type of analysis so we looked at more conditions than most have. We looked for those narrow windows of vulnerability where things “stick” or respond in a sluggish fashion. We can show that any UFLS program will have some combinations of overload and modeling assumptions where frequency recovery is slow and sluggish. If you don’t look for this problem, you are not going to find it, so we conclude the other regions would have as much trouble meeting this as the new MRO UFLS program. Perhaps an intuitive example will help. Basically over the range of coverage provided by load shedding, there will be certain combinations of factors which lead to frequency settling out just above where the next block picks up, and then we have to rely of governor action (or additional small blocks of load shed on delay) to pull the frequency back up. The rate of frequency recovery is also going to be a function of inertia, and if we have lots of units on which are partly loaded, the effective “system based” inertia will be high and rates of change of frequency will be lower. In comparison, if frequency would have dropped a little lower we would have quickly shed load and driven frequency up above 60 Hz, potentially reaching our maximum frequency. Another example to consider is what happens if the system overload is just a little larger than the size of the UFLS program? All load is shed and we are still below 60 Hz, but frequency might be close enough to 60 Hz for operators to respond if they are given sufficient time to respond.

2.18 Generation protection settings also have to anticipate what happens if UFLS fails

My biggest concern with use of short time delays at frequencies above 59 Hz is based on a completely different issue. Murphy’s Law is alive and well when it comes to power systems. All of us have to consider what might go wrong during a system breakup. Breakups can be chaotic and different each time they happen, and consequently load shedding performance can vary. There is a chance the “perfect plan on paper” may fail to work as desired in the face of some unanticipated event. At some point operators may have to intervene, and they need assurance that generation will not be tripping as they manually try and drop load. The fact that frequency can stall us out below 59.5 Hz is reason enough to insist that we use generation protection time delays according to actual equipment capabilities. In general, generation off-nominal frequency protection time delays need to be longer than the expected frequency recovery times shown in simulations to give us some margin, and as we get closer to 60 Hz, we want to take advantage of the long delay times allowed by actual equipment capabilities. This is needed as part of the “hedging our bets” process. This helps compensate for the uncertainty we cannot factor into the program design like relay failure, operator error, random events, loads changing in real time (affecting block size as % of system load), effects of voltage transients that effectively increase load, and so forth.

A real life scenario many of us have seen before is where UFLS programs cycle between underfrequency to overfrequency and back into underfrequency. On the second drop into underfrequency, we no longer have all or any of our automatic load shedding left. With luck, the frequency will stall out close enough to 60 Hz to allow manual operator initiated actions. Planners try to prevent this in the design, but in real life this cannot always be prevented. For instance, load shedding itself can overstress lines and cause further breakup of an island into smaller islands, one with a surplus of generation and one with too much load. The island with too much generation is going to suddenly have severe overfrequency problems. Emergency overspeed controls which are in place to deal with full load rejection will kick in somewhere above 61.2 Hz (as previously described). At steam plants these load rejection controls will slam all valves shut. Power plants can’t stay in this condition for very long before something gives. Let’s say this leads to unpredictable random tripping of thermal generation, and frequency drops back below 60 Hz. As frequency drops the remaining steam turbine valves open back up, so the initial loss of generation my save the rest of the generation and frequency may actually settle out below 60 Hz, but with frequency still high enough that actual equipment capabilities would allow operators plenty of time to respond. We need to take advantage of this capability, and set generation tripping times accordingly.

Another example would be having an overload which is slightly higher than the size of the load shedding program. All load is shed, but frequency remains below 59.5 Hz. We then rely on manual operator actions to pull us back the rest of the way.

2.19 A very troubling trend

One of the most troubling things we uncovered in the MRO UFLS effort is that some manufacturers are now designing equipment which does not have the off-nominal frequency capability it once had. It seems this has occurred with CT's and is probably also happening with wind generation. I mention this trend as it is important that we don't build in weak links like this as the system expands or else we are going to seriously affect reliability. We need units which can briefly operate down to at least 57 Hz to improve chances of surviving islanding events. Future trends in general are all at odds with being able to create a good underfrequency safety net. If NERC prescribes limits which never allow us to operate below 58 Hz, or to limit operation at 59.3 Hz to only 30 seconds, equipment will start being built accordingly.

Combustion turbines cannot hold constant power as frequency drops unless they were only partly loaded to begin with. There are thermal issues involved, which is why fully loaded units only have a momentary governor response to underfrequency. The governor is quickly overridden by the thermal controls. The percentage of power which drops off due to a frequency decline is going to be about the same percentage as the percent change in frequency, or higher. A lot of new CT's have been added over the last 10 years or so, and we are likely to see more of these in the future.

High concentrations of wind generation are really going to cause problems unless more sophisticated designs are used. The problem is that older units are inherently unstable and will just trip off right away. Newer units can probably operate down to 57 Hz, but all inertial effects are masked from the system, so system inertia is going to drop and UFLS relay coordination is going to become very difficult because that low inertia means high rates of change of frequency and this can affect load shedding programs in several ways. In the MRO UFLS program, we anticipated this problem and examined lower "system based" inertia than what we have today. We saw coordination problems, but this information was still used to help us define a robust UFLS program. It was obvious that coordination would be next to impossible if inertia got lower than what we looked at. Lower system based inertia means lower minimum frequencies and higher frequency overshoot. (This is a consequence of relay detection times and breaker operating times being too slow to stay on top of the fast drop in frequency, so we end up with relay coordination problems and shed too much, too late.) I am not aware of wind units having any type of governor although I was told by an individual in GE's Power Systems group that designs will be changing over the next 10 years. For instance, GE is adding a governor to their wind generation. I am not sure how that works. Most likely it would work well on overfrequency, but I am not so sure about underfrequency. Likewise they might be able to use software that controls the power electronics associated with variable slip induction generator to unmask the inertial effects (or mimic such effects) to help the grid a bit. However, actual inertia of wind generation is still going to be low. I also heard that a new trend is going to be use of permanent magnet synchronous generators for wind generation. Synchronous generation is probably going to be an improvement over induction generation, but I have no idea if this will actually be a benefit to the system or not. Whatever the wind industry comes up with, it is unlikely to be as robust and useful as traditional steam and hydro generation, and it will just make the task of providing a safety net all the more complex, or perhaps nearly impossible, once huge amounts of wind generation are added to the grid.

3.0 Observations concerning historical reliability criteria, and a proposal to adopt a different type of "measure" to assess UFLS reliability

3.1 Reasonable Expectations

It appears that engineers recognize that we cannot apply performance measures to real life load shedding events since it would be an inconsistent application of how we apply operating type criteria in general to such low probability multiple contingencies. In addition, the parties who are trying to fix the problem do not need to be blamed for the problem itself should they be unable to "fix it". That is sort of pointless. I believe that engineers also seem to recognize the only perfect program that exists is the one on paper. In real life it has to deal with things we probably have never anticipated and if disturbances are too severe, load shedding may not prevent collapse. Load shedding is just a tool and it has limits. That is just an engineering reality. It should also be obvious that a lot of coordination is involved.

3.2 Coordination is the key to ensuring reliability objectives are met

Good coordination is going to be what ensures reliability. However we sure seem to be doing things which discourages coordination at large. This new deregulated world has defined transmission as separate from generation when in reality all these parts together form a giant complex machine called the “system”. For compliance, we created the concept of “Legal Entities” who can be sanctioned, and entities such as NERC regionals that are apparently something else. We invented terms such as planning coordinator. This all gets confusing, especially to me, as I have had little experience with structural changes going on. What I see is that much of the carefully built up infrastructure that we had to promote reliability is being altered to the extent it is hard to recognize just where we are at today. As we keep creating distinctions which do not follow engineering realities, it will just make all of our coordination tasks much harder to achieve. It is hard to see how this helps reliability. For instance, I was told the NERC regions cannot be in charge of design and analysis of UFLS programs (in conjunction with members of course) because they are not a “Legal Entity”. However this is how reliability matters were always coordinated and this is still the logical way to achieve coordination between all of the parties who need to get involved. All of us in the industry have to work together and pull in the same direction to develop an appropriate safety net. The NERC regions have the organizational structure to pull everyone together to do this type of coordination through taskforces that represent the industry at large. It is necessary to get a broad base of different people involved in the UFLS study process. It ensures you have lots of eyes on the product, lots of different viewpoints to consider, and it also helps in selling and explaining the final program to everyone in the end.

3.3 We have to consider the system in total

When it comes to analysis, the power grid is all one giant complex machine all the way down to the customer load. You have to consider all the parts to figure out the dynamic response of the whole. We have to consider everything which affects the frequency decay dynamics. There is no distinction that can be made on the basis of voltage class of the components of the system. This is why I am a little uncomfortable with excluding some generation from having to coordinate with load shedding programs as done in PRC-024 and PRC-006 just because such generation is connected to a lower voltage. If such generation, in total, is significant to the study work and final UFLS program, then it needs to be included. Let the study group decide what is significant or insignificant.

3.4 The evolution of PRC-006

I understand that PRC-006 has now evolved into something closer to a “continent wide” planning type of standard to guide us in designing UFLS programs. I have tried to explain why the tradeoffs associated with load shedding programs are best evaluated by groups of technical experts which are closest to the problem and why this standards process should not be micromanaging the analytical process or be setting design type of performance criteria. Likewise, it is a poor idea to have a standard such as the proposed PRC-024 that tries to establish generator protection settings up front. I see these approaches as actually being a threat to reliability by providing the wrong incentives (I also have technical reasons why I do not agree what is being proposed). NERC should allow the technical groups to work out these types of details. Such groups can give this subject the thought and focus that it deserves, and this careful deliberate thought process is what will ultimately ensure we are meeting reliability objectives.

3.5 A recap of my concerns

I believe that I have explained why I am uncomfortable with the idea of using specific frequency and voltage characteristics as a design “measure” in the UFLS standard. I will recap the issues. The various performance objectives of limiting underfrequency, limiting overfrequency, and of providing the largest safety net possible are mutually exclusive. The easiest way to satisfy all three (perhaps the only way) is to put in a smaller program and then the program will work well over this smaller range of overloads but will be inadequate if larger overloads occur. I believe we need to allow programs which are larger than the minimum, when appropriate, and those programs will have poorer performance according to these “measures” but I will argue that only the program which is “large enough to get the job done” will give us the reliability we are looking for. I also recognize there are limits to what UFLS can accomplish, which is why I do not want to mandate that UFLS programs have to shed more than the stated minimum, but I want to encourage folks to do this if it makes sense. Neither the frequency nor the voltage “measures” really tell us if we have the right safety net in place and both measures are subjective (i.e. what performance for what set of assumptions).

Concerning voltage, I recognize that volt/Hz issues exist, but I do not feel this needs to be addressed in the standard. The real issue is how to minimize overvoltage problems as we shed load.

To some extent I believe this discussion also helps explain why it can make sense to have different UFLS programs for different portions of the system. That is because different areas have different needs, and possibly unique regional aspects to consider. The final UFLS program definition is just an outcome of working though the problem and iterating towards a best compromise for UFLS program design.

There is no one single “best” program. We have lots of options and each represents different tradeoffs. In reviewing technical literature, we find there are also lots of different opinions expressed by different authors, and I imagine this influenced how programs were created in the first place. I believe the existing load shedding programs in North America are probably getting the job done as long as coordination with generation protection has been achieved. Some programs may be a little more refined than others, but load shedding is inherently a crude and drastic action. A periodic review process will go a long way to ensuring we keep programs up to date. We do not want this review process to be too much of a burden, but we want some process in place so that we can do detailed analysis if needed. My experience has been that a full blown UFLS study process will take 2 to 3 years to complete, perhaps 1 to 1.5 years if folks are fully trained, spend all their time on this one subject, have the study scope worked out ahead of time, and have all the tools developed that are needed. That is what it took groups I have been involved with to collect the information, to build the models, to run meetings, to do the analytical work, and so forth. I would not want to have to do that over and over again on a 5 year schedule. A much more simplified review would be appropriate for the 5 year review. A full study mode type of ground up review is only needed once in a long while or in response to some major break up or in response to drastic changes to the topography of the grid.

I feel that UFLS “measures” used for compliance purposes should stay away from frequency and voltage. We need a different type of measure. UFLS is really sort of something different and unique, and I think that justifies treating it differently than other Standards to the extent that it makes sense to do so. All the other criteria try to keep us from ever getting to this point. UFLS is what we do when we are past the point where most criteria apply. It is a drastic, one shot, last ditch effort and we can’t make it into something other than what it is. Some accelerated loss of life to equipment will be involved. Loss of equipment life and financial costs are also associated with a system that goes black. We need to consider all of these tradeoffs, especially when people get too conservative on generation protection to the point where if affects UFLS performance objectives. We need flexibility to accept the right tradeoffs. The UFLS standard can avoid the subject of voltage and frequency performance altogether since we know this will be addressed in the study process in an appropriate level of detail.

3.6 A suggestion to adopt a completely different type of “measure”

I have consistently stressed how UFLS analysis is an iterative process. I hope everyone can understand why I feel this standards drafting process also has to be iterative, and why we may need to change course as we move along the learning curve.

I believe the standards drafting teams need to back up and try a different approach which emphasizes “measures” which consider a completely different aspect of UFLS related effects on reliability. The question is, what are the right measures? The first thought that comes to mind is that load shedding enhances reliability by creating a safety net. Perhaps we should be only be checking to see if the safety net exists, to see if studies say the safety net is an appropriate safety net, and so forth. Would it be possible to use these aspects of the issue as our “measures”?

I think it makes perfect sense to “measure” if we are fulfilling the basic aspects of load shedding obligations. The “measure” would be “have you done activities x, y, z?”. We would then skip this entire discussion of what type of performance, on paper, is appropriate. Instead we would focus on the big picture, which is to make sure we have a reasonably effective safety net in place. The “measures” could become simple pass/fail checks to see if we have covered the basics of implementing an appropriate UFLS program. I suggest that we keep it really simple. It will be easy to check on things like: 1) has an appropriate program been designed which satisfies a checklist of items that have to be considered such as coordination with generation protection, 2) has the program been implemented, 3) has the program been periodically reviewed, 4) have any changes that came about from the review processes been implemented in a timely fashion, and so forth. I know I am in the position of having to sell this approach, as this is not what FERC and NERC set out to do. However, when you look at all the complexity involved, and what the bottom line is, this approach makes sense. I am sure it would be acceptable to the industry and that it would satisfy reliability objectives so long as we get the appropriate study groups in place. That really means getting the right people involved, who have the needed skills to work through things. I think a NERC region has the organizational structure to pull this type of coordination off. We are all familiar with that structure. Inventing some new type of group structure just adds another layer of confusion to deal with.

The standards should stick to the broad-brush type of stuff. More to the point, this standard should be written to ensure the following:

* That Automatic Underfrequency Load Shedding (UFLS) programs are properly developed, documented, and coordinated. This includes coordinating generation off-nominal frequency protection settings with the expected frequency recovery characteristic of the load shedding program.

* That groups/regions have studied UFLS and have designed an UFLS program that fits the unique characteristics of the region (including any subregions) and that UFLS programs address any specific issues that are relevant to UFLS.

* That groups/regions have documentation that specifies the details of the desired UFLS program so it can be implemented.

* That groups/regions do periodic reviews including reports on actual UFLS performance following major disturbances.

* That individual utilities have implemented load shedding in a fashion which is a reasonable fit to the stated regional load shedding program and that documentation is available (the term “reasonable fit” is used in consideration that no single utility can ever get a perfect match to a something like 5 blocks of 6%).

* That each group/region sheds at least a minimum amount of load.
That some form of coordination or dialog exists between groups/regions which study load shedding in adjacent areas.

* To ensure that modeling data is collected and compiled for stability cases

We recognize that PRC-006 addresses some of these points adequately, but as previously discussed, we have serious concerns with how some of this is being handled.

Let the groups/regions define:

* how much load to shed in total (it is OK to set a minimum level in the NERC standard, so long as we are clear that this implies a higher level might be more appropriate)

* size of load shedding blocks

* frequency setpoints

* targets for min/max frequency deviations and allowable times above and below 60 hz (these are design targets only, and may have to be reconsidered and revised after looking at study results…this is an iterative process that has to be carefully thought out as study work proceeds)

* generation off-nominal frequency tripping minimum time versus frequency protection settings to ensure coordination with load shedding

* analytical methods

* any other unique requirements or aspects of regional programs

3.7 The existing NERC UFLS related guidelines and criteria are excellent

As far as UFLS design goes, the broad guidelines in the existing NERC UFLS related standards are excellent, and following that lead will allow us to reach the correct final conclusions. Somehow we have to retain all of these guidelines.

4.0 Can the measures in PRC-006 be tweaked, and is that even a fix?

I believe the direction taken in PRC-006 and PRC-024 is seriously flawed making a discussion of how to tweak and fix things sort of meaningless. That is why I am proposing we adopt “measures” that are based upon the “activities” required to get a safety net in place instead of a measure of “technical details”. However, if we are unable to change directions, then the proposed performance “measures” have to be softened to allow exceptions as based on needs identified in analytical work and to base criteria on actual equipment capabilities. We need a lot of freedom so that groups can make the needed compromises and adopt the right performance criteria.

I really don’t think that PRC-006 should be a planning type of standard that tries to micromanage the design process. My opinion is this approach will not ensure reliability objectives are met. We only need to point out the various issues which planning engineers have to consider (this is clearly spelled out in old NERC UFLS standards) and they can take it from there and work through the study process. Planning engineers will understand what needs to be done better than anyone else. Just turn them loose and they will get the job done, and then we will have the UFLS program specifications complete with criteria on how to coordinate with generation protection.

The existing NERC UFLS related standards are still highly relevant materials which should be used as guidelines on how to develop load shedding programs.

While it is reasonable to start with tentative performance targets as far as design work goes, I consider this as something best left to a study group of the technical experts. Study work has to be performed to find out what is possible before you reach a final decision about what is the best compromise for an UFLS program. In the end, the final program will have to consider if a given area has any unique characteristics that have to be considered, and study work will involve tradeoffs and compromises concerning minimum frequency, maximum frequency, time spent below 60 Hz, and so forth.

4.1 List of specifics related to PRC-006.

R1- a group of planning coordinators is not going to be the equivalent of the type of broad based participation we have historically achieved through the NERC Regionals via the existing committee structure. The group concept is a step in the right direction, but the concerns that we can only apply mandatory standards to “legal entities” appears to be leading to artificial constraints that are making it more difficult to achieve the needed coordination and this just makes it more difficult to create the safety net that we want.

R2-stresses consistent application across the region, and I would argue that only the final analysis of the system will tell you if this makes sense. There may be subregions which have different needs. In MRO, the Canadian systems have different needs than the US portion of MRO.

R3- this says we need criteria on how to select islands. It strikes me as odd that we need “criteria” on how to reach a conclusion. Shouldn’t this just say that analysis shall consider possible system break up patterns that may form islands? For the US portion of MRO, we did not try to say what the most likely island would be. Instead we identified where the break points were, and used this, along with the MRO geographic boundary, to break the system into pieces. We felt these pieces alone, or aggregated together, represented our possible islands. We evaluated the needs of each of the pieces, and evaluated how to model each piece. We concluded that one set of simulations covering a range of inertia, damping assumptions, and overloads would inherently cover all of these different islanding patterns. So we performed our analysis in a fashion that allowed us to avoid having to make a very specific determination of what the island would be, and instead found a way to make something work in a more global sense.

R4-I agree that coordination with neighboring regions is required, but I do not know how to resolve differences of opinion between regions. Perhaps this is nothing to worry about since it is likely to take care of itself. Are we trying to reach a consensus between regions, or just trying to share information and to create a forum for discussion? Obviously where breakups cause islands that straddle different NERC regions, we need to jointly evaluate that island. Even if this coordination is only to share information, it still allows everyone to learn from each other and is going to be quite valuable.

R5-is about identifying islands. I think it is the exact wording of this section that bothers me although I agree with the intent. I prefer to focus on break points that may lead to islands. The difference is subtle, but for the US portion of MRO we did not identify "an island", in the traditional sense, that was the basis for our design. We identified how the grid may break up. We used these break points to break the system down into pockets of load and generation, and then we examined each pocket. These pieces, alone or aggregated together, are our possible islands. We did not try to say which was most likely to form. Some of this represents high unlikely conditions. Some of our parts were not even expected to be islands, and were just the left over parts of the foot print after the obvious break points were identified. The southern and eastern edge of MRO is tightly interconnected and less likely to island, but we still were able to reach a conclusion as to what load shedding level was appropriate for even these areas. We examined load shedding requirements and modeling characteristics of each part. In the end we decided that a 30% load shedding requirement was adequate for each "piece" except for the systems in Saskatchewan and Manitoba. The MRO approach was to allow those regions to have their own programs, so they could satisfy their needs, and we just concentrated on the US portion of MRO. In the US portion of MRO, we found an UFLS program that should work for any of these island patterns as each of the geographic regions we looked at had similar characteristics and load shedding needs. We could model a range of conditions using the equivalent inertia modeling approach and we would inherently capture everything at once. Although our analysis was rigorous, we avoided having to decide on what our island has to be for design purposes, and instead came up with something that is likely to work for about any islanding pattern. With this said I can propose a wording change, I would rather say something like:

"…shall identify islanding patterns that can be used as a basis for designing an UFLS program. This shall consider:"

R6-addresses the "technical parameters" that I have so much trouble with. I have problems with all of this, as previously discussed at length. I do not like R6.1, R6.2, R6.3 at all, but as part of the study process we would normally come up with parameters of this type after we work through all of the tradeoffs. However I expect we would decide on different technical parameters in the end than is being proposed in PRC-006 and PRC-024. Requirement R6.4, the volts/Hz requirement, does not seem appropriate, and may not have to be addressed at all in an UFLS program. The need to address volts per Hz would depend on how low of a minimum frequency we are expecting. This does not appear to be an issue for programs where the minimum frequency is above 57.2 Hz or so. This might be relevant to isolated hydro systems with large load shedding requirements because hydro systems can accept much lower minimum frequencies than thermal generation (below 57 Hz) and load shedding programs may want to exploit that characteristic. However this would be something that study groups would apply as needed, and does not need to be in a standard.

R7-is about the need to do periodic assessments. I agree we need a periodic assessment of some sort. Full blown studies on the other hand are seldom required unless some inherent flaw in an existing program is identified and we need to start with a fresh look at everything. I do not agree with meeting the performance characteristics in R6. We should meet performance characteristics which are defined as a result of the load shedding study process, and not just something that is tossed out up front.

I think there are other ways to assess the risk of having units trip off early than just running simulations. This almost implies we have to use full stability cases as our only analytical method. Let engineers figure out how to study the problems using whatever tools, methods, and calculations they feel are appropriate.

If we require some assessment of load shedding "need", then generation which drops off early can be evaluated in terms of how it affects the "needs" assessment, or we can demonstrate how loss of such generation affects programs in a general sense. Personally I feel we should not allow any generation to trip any sooner than prescribed by the final UFLS programs requirement for generation protection settings and delays. On second thought, there will be a few exceptions: units which are unstable like the older wind units, non-utility generation tripped along with load on a feeder as part of UFLS, and perhaps other exceptions where inadvertent tripping cannot be avoided. However, as a general principle, we should not allow any generation to trip prematurely via dedicated under frequency relays unless some offsetting action like tripping additional load can be done. We should not allow generation tripping on overfrequency using dedicated relays (other than tripping actions related to load rejection protection that we do not want to be messing with), unless such overfrequency tripping of generation is a planned activity that is a feature of the UFLS program used to rebalance load and generation.

R-8 shouldn't this database/modeling type of information be compiled as part of the regional model building process? NERC regions do this type of thing today, why is this group of Planning Coordinators getting involved in this. We use the NERC regions to do our coordinating activities, so why depart from what works? I need to understand the reasoning behind this before I can comment further.

R-9 appears to say that everyone shall trip load in accordance with the UFLS program. I agree with the intent.

5.0 Appendix

I wrote a lengthy document and sent it to NERC when the first draft of this standard was out for comment. As I just emailed that document in directly and did not submit that document through the on-line data forms where comments are provided, my critique did not show up along with all of the other comments. So, I am submitting some of this again as an appendix. Below are the portions of my original document which address the physics of the problem. I imagine some of this has already been discussed above. However, this is still a good review.

5.1 UFLS in Context
Before we can really address the Under Frequency Load Shedding Regional Reliability Standard Characteristics document in specific detail, we need to provide a context.

Reasonable expectations:

* Under frequency load shedding (UFLS) is a one shot, last ditch attempt to save the grid from total collapse for some event that typically far exceeds anything that planning or operating criteria addresses.

* Load shedding is inherently a crude and drastic action.

* Load shedding has its limits, it can't protect against everything.

* There is no perfect UFLS plan, just lots of different options with lots of different tradeoffs.

* In any discussion of UFLS, we need to keep in mind that load shedding might not work as desired in real life, and we can only make it "perfect" on paper, for some tightly defined scenario subject to a lot of assumptions.

* Just about any UFLS program will work great for some overload level, but at a different overload levels it might shed too much and cause a frequency overshoot or shed too little and then frequency might stall out. We can try to minimize such problems, but not totally eliminate them.

* Doing "something" to try to quickly correct a major load/generation imbalance is better than doing nothing, and history has shown that load shedding generally works well, but it is not always trouble free. Don't penalize honest efforts to provide a safety net.
The best we can do is to eliminate any obvious flaws in the UFLS program design and try to anticipate complications.

5.2 Trade-offs, Compromises, and Uncertainty
When it comes to designing a program, engineers find there is considerable uncertainty associated with most every aspect of the problem. Consider:

* We do not know what may lead to break up, or necessarily what islands may form or what the final imbalance may

be.

* There is no perfect way to determine how islands will form, especially if the region is tightly interconnected. Study tools such as stability cases may help identify possible islands, but experience and engineering judgment is perhaps more important.

* Factors that affect load shedding performance are not necessarily under the control of the utilities who put in load shedding.

* At best, we can bracket a range of unknowns and make educated guesses, and then try to find a program that works as intended, the most often, over the widest range of conditions.

* This type of work involves lots of trade offs and compromises.

Compromise also applies to simulation methods. No simulation approach is going to be perfectly suited for this type of analysis and each of the standard ways of assessing UFLS has strengths and weaknesses.

* Full stability cases are very detailed and good for a very specific spot check, but poor for generalizing. They do not necessarily provide a better way of assessing system performance than a more empirical approach.

* Relay application guides typically suggest using the equivalent inertia approach to dynamic modeling where everything is equivalized down into the simplest form that captures the frequency decay dynamics. This simple approach allows rapid prototyping, but it ignores the voltage transients and governor action.

To better understand the complications of UFLS design, we need to give a brief statement of the problem:

* When we have a mismatch of load and generation, the frequency will decay or increase until we reach a new equilibrium between generation torques and load torques.

* If generator power stays constant, then generation torque will increase as frequency drops (power = torque x speed).

* Load torques decrease as frequency drops according to the load damping constant.

* At some new frequency, we once again reach equilibrium where load and generation torques are equal and this becomes the new synchronous frequency.

* Without load shedding we could see frequency decay low enough that generation protection will have to instantly trip generation to prevent excessive loss of life. At that point, the system collapses.

Load shedding objective and tradeoffs:

* We use UFLS to quickly drive frequency back towards 60 Hz so that we do not risk losing additional generation on underfrequency.

* Loadshedding must not cause overfrequency problems that lead to uncontrolled tripping of generation that will precipitate another underfrequency event.

* To improve minimum frequency, we can start shedding sooner (higher frequency setpoints), decrease frequency spacing between relay settings, and shed load in fewer blocks of larger size…all of this increases frequency overshoot problems.

* We can also improve minimum frequency by deciding to cover a smaller imbalance to begin with.

* To decrease frequency overshoot, we can shed load in smaller blocks, increase frequency spacing between relay settings, and use more load shedding blocks in total…all of this decreases the minimum transient frequency for the

largest overloads we cover.

* Overfrequency based tripping of generation or restoration of load can also minimize frequency overshoot, at the risk of causing the frequency to cycle back into another underfrequency event.

* Underfrequency recovery times can be improved by shedding some additional blocks of load on delay, at the expense of increasing the risk of frequency overshoot.

The rates of change of frequency and load damping characteristics affect relay coordination:

* Large overloads give high rates of change of frequency

* Unit inertia represents energy stored in the rotating mass. Inertia (for a given overload level) affects the rate of decay of frequency: high inertia = slower frequency rate of change, low inertia = fast frequency rate of change.

* Load damping affects the final frequency where equilibrium is reached. Low damping means larger frequency deviations for a given imbalance.

* Generally it is difficult to design a program for low inertia, low damping, high overload conditions. This condition gives the lowest transient frequency, and the fast frequency decline affects relay coordination that can cause overshedding.

* Relay coordination is much easier if inertia is high, but recovery back towards 60 Hz will be slower when inertia is high.

Let's consider some of the hard to quantify factors that affect performance:

* load damping (utilities have no control over the dynamic characteristic of loads, and we are not sure how much damping we have or how it varies in time or by season)

* the type of generation on the system

* the system inertia on system base (energy stored in rotating mass relative to remaining generation in island)

* if asynchronous islands are still being fed by DC lines (this is power with no inertia associated with it, which drives system based inertia down), or if frequency deviations cause DC lines to trip

* the magnitude of the imbalance between load and generation

* the net governor effect (not much if units are base loaded, running in boiler follow mode, or overridden by power-load controllers)

* overvoltages (and how can we moderate voltage deviations)…as load is shed the voltage will swing around, and overvoltages can increase load, offsetting the benefits of load shedding which in turn affects the rate of frequency recovery

* random factors, such as unit trips, industrial load trips, additional line outages (including planned separation schemes), and so forth

* Wind generation…the older vintage of wind generation will drop off-line as frequency declines…how much will be on-line?

* Combustion turbines…they are thermally restricted. Assuming a combustion turbine is operating close to its temperature limit to begin with (i.e. the typical condition when loaded high), the net result is that turbine power drops as frequency starts to decline, aggravating the imbalance.

* The actual sequence of events that leads to islanding can have considerable influence on overall performance, yet typically the best we can do in simulations is to form and island all at once by opening all the tie lines at the same moment. This is because we do not get major system breakups from “credible events” that we can easily model. Usually load shedding occurs following a complicated sequence of things going wrong that no one could have ever predicted ahead of time.

* Load shedding itself may overload transmission lines, and lead to further system breakup and islanding.

* Overshedding can lead to unintended random loss of additional generation in response to overspeed (due to various internal problems at the facility), and cause another cycle into underfrequency from which we might not recover.

Now consider future trends:

* Industry trends show that load damping is decreasing, and load damping is not precisely known to begin with. Damping also varies in real time.

* The trend has been that inertias of new units are lower than in the past.

* Some of the newer wind generation provides no inertial effects as rotating mass is decoupled from the electrical grid by the controls that allow variable slip operation of the induction generator or because they are coupled to the AC system through an inverter.

* Wind generation is intermittent, difficult to factor into UFLS programs, and with all of the different makes and models out there, it is difficult to generalize how these units will actually respond and how many will ride through a frequency swing.

Different areas have different load shedding needs, and areas that need to shed a lot of load have to make more compromises as far as transient frequency and voltage performance go:

* UFLS programs that shed more load will also experience lower minimum frequencies, higher maximum frequencies, and be more prone to relay coordination problems (which increases the chance of overshedding). On the positive side, these programs provide the largest safety net.

* Programs which shed the minimum amount of load can use smaller load blocks or fewer load shedding stages which improves frequency response and improves relay coordination over the smaller range of overloads covered. Obviously if overloads exceed the capacity of the program, the system will collapse.

In summary, everyone needs to apply common sense and good judgment when dealing with UFLS issues, and compromises have to be carefully considered at every step of the decision process involved with design and implementation.