Introduction:

The SDT received comments from 138 different people, as shown on the next pages. These people represent more than 70 different companies, all NERC Regions and 6 of the 9 Industry Segments. The Operate Within Limits SDT (OWL SDT) thanks all who participated for their time and efforts in providing valuable input to the refinement of this new standard. The SDT believes that the technical issues associated with this standard that were raised during the first ballot of this standard, have now been resolved.

Changes Made to Bring a Common Understanding to the Identification of IROLs :

The OWL SDT met jointly with members of the Operating Limits Definition-Task Force and the Determine Facility Ratings (DFR) SDT at the request of the NERC Operating Committee to reach common agreement on the definition of IROLs and a generalized methodology for identifying which SOLs are further classified as IROLs. During this meeting, participants determined that the identification of IROLs is most easily accomplished when the SOLs are developed. The IROL-related information the industry indicated it wanted provided to real time operations personnel is typically identified during the various activities designed to identify SOLs.. Based on these observations, the participants in the joint meeting recommended moving the IROL identification and communication requirements from the Operate Within IROLs Standard to the DFR Standard and recommended soliciting industry feedback on the appropriateness of this move. In addition, the OLD-TF agreed to align its activities associated with SOLs and IROLs to that proposed in the revised DFR Standard.

The participants in the joint meeting agreed that the criteria used to determine whether an SOL is also an IROL is the same for both the planning and the operating horizon:
If exceeding the SOL results (or could result) in one of the following, then that SOL is also an IROL.

- Instability
- Uncontrolled separation
- Initiation of cascading outages

The DFR SDT has agreed to solicit feedback on the appropriateness of moving the requirement to identify and communicate IROLs from this standard to the DFR Standard.

Balloting:

The SDT believes that this standard, or any other new standard, will not receive sufficient approval because many members of the Registered Ballot Pool voted ‘no’ on this standard for one of the following reasons, and many of these balloters have indicated that they will continue to vote ‘no’ until these issues have been resolved.

- **Continued Ambiguity about the Future of the Reliability Coordinator**
  The Reliability Coordinator does not appear in the Functional Model, but the Functional Model Technical Document indicates that the Reliability Coordinator is expected to continue to exist. (From page 38 of the Functional Model Technical Document:

  > “As this paper explains, the lack of the Reliability Coordinator in the Functional Model should not imply that the RC won’t exist. In fact, we expect it to.”

  Having both Reliability Coordinators and Reliability Authorities with similar sets of rules is confusing and may lead to unclear lines of authority during real-time operations.

- **Financial Sanctions for Non-compliance Aren’t Fully Supported**

While some Regional Compliance Programs use financial sanctions and feel that these are good tools for motivating compliance with NERC Standards, at least one Region is using letters without financial sanctions, and the member of that Region feel that the letters, by themselves, are good tools for motivating compliance with NERC Standards.

- **Field Testing**
  The Compliance Templates for Operating Policies and Planning Standards all received field testing before they were implemented. Some industry participants expect that all new standards should be field tested before being implemented. There appear to be misunderstandings surrounding the responsibility for determining whether field testing should be conducted, as well as misunderstandings about the purpose of field testing as applied to new standards.

The OWL SDT will post the revised OWL Standard for review with the DFR Standard, but will delay balloting the OWL Standard until the above issues are resolved and the industry has reached consensus on the content of the DFR Standard.

Commenter	Organization	Industry Segment								
		1	2	3	4	5	6	7	8	9
Rusty Foster				X						
Dan Boezio	AEP	X								
Anita Lee	AESO		X							
Dale McMaster	AESO		X							
Ken Skroback	AL Electric Coop	X								
Ken Githens	Allegheny Energy Supply					X				
William J. Smith	Allegheny Power	X								
Michael D. Zahorik	ATC	X								
Peter Burke	ATC	X								
Marv Landauer	BPA	X								
Ed Riley	CAISO		X							
Roger Westphal	City of Gainesville			X						
Alan Hale	City of Tallahassee					X				
Karl Kohlrus	City Water, Light & Power					X				
Bob Remley	Clay Electric Cooperative				X					
Bill Thompson	Dominion	X								
Jalal Babik	Dominion	X								
Craig Crider	Dominion	X								
Jack Kerr	Dominion	X								
Bill Thompson	Dominion	X								
Randy Hunt	Dominion- VA Power	X								
Don Reichenbach	Duke Energy	X								
Uma Gangadharan	Entergy	X								
Ed Davis	Entergy Services	X								
Sam Jones	ERCOT		X							
John Blazekovich	Exelon Corp	X	X			X	X			
Joe Krupar	Florida Municipal Power Agency			X						
Ed DeVarona	Florida Power & Light Co.	X								
Patti Metro	FRCC		X							
Linda Campbell	FRCC		X							
Doug Newbauer	GA System Operations	X								
Roger Hunnicutt	Gainesville Regional Utilities					X				
Phil Winston	Georgia Power Company			X						
David Majors	Georgia Power Company			X						
Mike Stafford	GRDA	X								
Dick Pursley	GRE		X							
Delyn Helm	GRE		X							
William F. Pope	Gulf Power			X						
David Kiguel	Hydro One Networks Inc.	X								
Roger Champagne	Hydro-Quebec TransÉnergie	X								
Don Tench	IMO		X							
Khaqan Khan	IMO		X							
Kathleen Goodman	ISO-NE		X							
Dan Stosick	ISO-NE		X							
Dave LaPlante	ISO-NE		X							
Garry Baker	JEA	X								
Mike Gammon	KCP&L	X								
Greg Woessner	Kissimmee Utility Authority			X						
Ben Sharma	Kissimmee Utility Authority			X						

Commenter	Organization	Industry Segment								
		1	2	3	4	5	6	7	8	9
Amy Long	Lakeland Electric	X								
Richard Gilbert	Lakeland Electric			X						
Paul Elwing	Lakeland Electric					X				
John Horakh	MAAC		X							
Joe Knight	MAPPCOR		X							
Tom Mielnik	MEC		X							
Dennis Kimm	MEC		X							
Robert Coish	MH		X							
Dave Jacobson	MH		X							
William Phillips	MISO		X							
Paul Koskela	MP		X							
Roger Brand	Municipal Electric Auth of GA	X								
Peter Lebro	National Grid	X								
Greg Campoli	New York ISO (NYISO)		X							
James Castle	New York ISO (NYISO)		X							
John Ravalli	New York ISO (NYISO)		X							
Michael C. Calimano	New York ISO (NYISO)		X							
Karl Tammar	New York ISO (NYISO)		X							
Robert Waldele	New York ISO (NYISO)		X							
Ralph Rufrano	New York Power Authority	X								
Al Adamson	NYSRC		X							
Brian Hogue	NPCC		X							
Guy Zito	NPCC		X							
John Swanson	NPPD		X							
Karl Tammar	NYISO		X							
Lawrence T. Hochberg	NYSRC		X							
Joe Roos	Ocala Electric Utility			X						
Peter Kuebeck	OG&E	X								
Todd Gosnell	OPPD		X							
Scott Moore	ORWG									
Larry Larson	OTP		X							
Jason Weiers	OTP		X							
Chifong Thomas	Pacific Gas & Electric	X								
Glenn Rounds	Pacific Gas & Electric	X								
Ben Morris	Pacific Gas & Electric	X								
Richard Kafka	PEPCO			X						
Bruce Balmat	PJM		X							
Phil Creech	Progress Energy - Carolinas	X								
Preston Pierce	Progress Energy Florida	X								
William Gaither	SC PSA	X								
Gene Delk	SCE & G	X								
Al McMeekin	SCE & G	X								
Lee Xanthakos	SCE & G	X								
Roman Carter	SCGEM					X	X			
Joel Dison	SCGEM					X	X			
Tony Reed	SCGEM					X	X			
Lloyd Barnes	SCGEM					X	X			
Clifford Shepard	SCGEM					X	X			
Lucius Burris	SCGEM					X	X			
Roger Green	SCGEM					X				

Commenter	Organization	Industry Segment								
		1	2	3	4	5	6	7	8	9
Steve Wallace	Seminole Electric Cooperative				X					
Carter Edge	SEPA				X	X				
Lynna Estep	SERC		X							
Dan Kay	So Miss Elec Pwr Assoc	X								
Matt Ansley	Southern Co	X								
Marc Butts	Southern Company Services	X								
Raymond Vice	Southern Company Services	X								
Dan Baisden	Southern Company Services	X								
Jim Griffith	Southern Company Services	X								
Jim Viikinsalo	Southern Company Services	X								
Mike Miller	Southern Company Services	X								
Monroe Landrum	Southern Company Services	X								
Gwen Frazier	Southern Company Services	X								
Steve Williamson	Southern Company Services	X								
Rod Hardiman	Southern Company Services	X								
Jonathan Glidewell	Southern Company Services	X								
Dan Richards	Southern Company Services	X								
Mike Hardy	Southern Company Services	X								
Carl Monroe	SPP		X							
Ron Ciesiel	SPP		X							
Robert Rhodes	SPP		X							
Bob Cochran	SPS	X								
Ron Donahey	Tampa Electric Company			X						
Beth Young	Tampa Electric Company			X						
R. Peter Mackin	TANC	X								
Khagan Khan	The IMO		X							
Mike Clements	TVA	X								
Mark Creech	TVA									
Larry Goins	TVA									
Edd Forsythe	TVA									
Jennifer Weber	TVA									
Jerry Landers	TVA									
Al Corbet	TVA									
Kathy Davis	TVA									
Darrick Moe	WAPA		X							
Mark Fidrych	WAPA	X								
Allen Klassen	Westar	X								
Martin Trence	XCEL		X							

List of Comments and Responses

Name	Company	1	2	3	4	5	6	7	8	9
Dan Boezio	AEP	x								
Raj Rana	AEP	x		x		x	x			
Scott Moore	AEP	x								
Anita Lee	AESO		x							
Dale McMaster	AESO		x							
Ken Skroback	AL Elec Coop	x								
Ken Githens	Allegheny Energy					x				
William J. Smith	Allegheny Power	x								
Michael D. Zahorik	ATC	x								
Peter Burke	ATC	x								
Marv Landauer	BPA	x								
Don Gold	BPAT	x								
Don Watkins	BPAT	x								
James Murphy	BPAT	x								
Mike Viles	BPAT	x								
Richard Spence	BPAT	x								
Ed Riley	CA-ISO		x							
Roger Westphal	City of Gainesville			x						
Alan Gale	City of Tallahassee					x				
Rusty Foster	City of Tallahassee			x						
Karl Kohlrus	City Water, Light & Power					x				
Bob Remley	Clay Electric Cooperative				x					
Randy Hunt	Dominion – VA Pwr	x								
Bill Thompson	Dominion VA Power	x								
Craig Crider	Dominion VA Power	x								
Jack Kerr	Dominion VA Power	x								
Jalal Babik	Dominion VA Power	x								
Don Reichenbach	Duke Energy	x								
Uma Gangadharan	Entergy	x								
Ed Davis	Entergy Services	x								

Sam Jones	ERCOT		x							
John Blazekovich	Exelon	x	x			x	x			
Joe Krupar	Florida Municipal Power Agency			x						
Ed DeVarona	Florida Power & Light Co.	x								
Linda Campbell	FRCC		x							
Patti Metro	FRCC		x							
Doug Newbauer	GA System Ops	x								
Roger Hunnicutt	Gainesville Reg Utl					x				
David Majors	Georgia Power Company			x						
Phil Winston	Georgia Power Company			x						
Mike Stafford	GRDA	x								
Delyn Helm	GRE		x							
Dick Pursley	GRE		x							
William Pope	Gulf Power Company			x						
Roger Champagne	H-Q TransÉnergie	x								
David Kiguel	Hydro One Networks Inc.	x								
Don Tench	IMO		x							
Khagan Khan	IMO		x							
Dave LaPlante	ISO_NE		x							
Dan Stosick	ISO-NE		x							
Kathleen Goodman	ISO-NE		x							
Garry Baker	JEA	x								
Mike Gammon	KCP&L	x								
Ben Sharma	Kissimmee Utility Authority			x						
Greg Woessner	Kissimmee Utility Authority			x						
Amy Long	Lakeland Electric	x								
Paul Elwing	Lakeland Electric					x				
Richard Gilbert	Lakeland Electric			x						
John Horakh	MAAC		x							
Gerald Rheault	Manitoba Hydro	x		x		x	x			
Joe Knight	MAPPCOR		x							

Dennis Kimm	MEC		x							
Dave Jacobson	MH		x							
Robert Coish	MH		x							
Tom Mielnik	MH		x							
William Phillips	MISO		x							
Paul Koskela	MP		x							
Roger Brand	Muni Elec Auth of GA	x								
Peter Lebro	National Grid	x								
James Castle	New York ISO (NYISO)		x							
Robert Waldele	New York ISO (NYISO)		x							
Brian Hogue	NPCC		x							
Guy Zito	NPCC		x							
John Swanson	NPDD		x							
Greg Campoli	NYISO		x							
John Ravalli	NYISO		x							
Karl Tammar	NYISO		x							
Ralph Rufrano	NYPA	x								
Al Adamson	NYSRC		x							
Lawrence T. Hochberg	NYSRC		x							
Joe Roos	Ocala Electric Utility			x						
Peter Kuebeck	OG&E	x								
Todd Gosnell	OPPD		x							
Jason Weiers	OTP		x							
Larry Larson	OTP		x							
Richard Kafka	Pepco			x						
Ben Morris	PG&E	x								
Chifong Thomas	PG&E	x								
Glenn Rounds	PG&E	x								
Bruce Balmat	PJM		x							
Phil Creech	Progress Energy – Carolinas	x								
Preston Pierce	Progress Energy Florida	x								

Dan Kay	S Mississippi Elec Pwr Assoc	x								
William Gaither	SC Public Svc Auth	x								
Al McMeekin	SCE&G	x								
Gene Delk	SCE&G	x								
Lee Xanthakos	SCE&G	x								
Clifford Shepard	SCGEM					x	x			
Joel Dison	SCGEM					x	x			
Lloyd Barnes	SCGEM					x	x			
Lucius Burris	SCGEM					x	x			
Roger Green	SCGEM					x	x			
Roman Carter	SCGEM					x	x			
Tony Reed	SCGEM					x	x			
Steve Wallace	Seminole Electric Cooperative				x					
Carter Edge	SEPA				x	x				
Lynna Estep	SERC		x							
Matt Ansley	Southern Company	x								
Dan Baisden	Southern Company Services	x								
Dan Richards	Southern Company Services	x								
Gwen Frazier	Southern Company Services	x								
Jim Griffith	Southern Company Services	x								
Jim Viikinsalo	Southern Company Services	x								
Jonathan Glidewell	Southern Company Services	x								
Marc Butts	Southern Company Services	x								
Mike Hardy	Southern Company Services	x								
Mike Miller	Southern Company Services	x								
Monroe Landrum	Southern Company Services	x								
Raymond Vice	Southern Company Services	x								
Rod Hardiman	Southern Company Services	x								
Steve Williamson	Southern Company Services	x								
Carl Monroe	SPP		x							
Robert Rhodes	SPP		x							

Ron Ciesiel	SPP		x							
Bob Cochran	SPS	x								
Beth Young	Tampa Electric Company			x						
Ron Donahey	Tampa Electric Company			x						
R. Peter Mackin	Trans Agency of N CA	x								
Al Corbet	TVA									
Edd Forsythe	TVA									
Jennifer Weber	TVA									
Jerry Landers	TVA									
Kathy Davis	TVA									
Larry Goins	TVA									
Mark Creech	TVA									
Mike Clements	TVA	x								
Darrick Moe	WAPA		x							
Lloyd Linke	WAPA		x							
Mark Fidrych	WAPA	x								
Allen Klassen	Westar	x								
Martin Trence	XCEL		x							

Questions about Definitions

1. Bulk Electric System

The SDT revised the definition of Bulk Electric System to clarify what portion of the electric system was included. Do you agree with the revised definition?

Original Definition: Bulk Electric System: A term commonly applied to the portion of an electric utility system that encompasses the electrical generation resources and high voltage transmission system (above 35 kV or as approved in a tariff filed with FERC).

Summary Consideration: The industry comments clearly indicated that using '35 kV' as a threshold for the bulk electric system was aiming too low. There were many suggestions for improvements to this definition, and the suggestions to use the definition embedded in the 'Introduction to the Planning Standards' seems to meet most commenters' suggestions, with the addition of a sentence to indicate that specific types of radial transmission lines are not part of the bulk electric system.

Bulk Electric System: The bulk electric system is a term commonly applied to that portion of an electric utility system, which encompasses the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission lines serving only load with one transmission source are not included in this definition.

'Yes' Responses	
Michael Zahorik; ATC; #1	35 Kv seems rather low voltage. 50 or 100 Kv may be a better value.
Most commenters agreed with this observation. The revised definition uses 100 kV or higher as a threshold.	
Mark Fidrych; WAPA; #1	The Voltage level appears too low, but some criteria needed to be established.
Most commenters agreed that 35 kV is too low. The revised definition uses 100 kV or higher as a threshold.	
R. Peter Mackin; TRANC; #1	Above 35 kV is OK, but I would prefer that the limit be above 59 kV.
Most commenters agreed that 35 kV is too low. The revised definition uses 100 kV or higher as a threshold. This is the threshold already adopted for use in Planning Standards.	
Roman Carter; SCGEM; #5, 6 Joel Dison; SCGEM; #5, 6 Tony Reed; SCGEM; #5, 6 Lloyd Barnes; SCGEM; #5, 6 Clifford Shepard; SCGEM; #5, 6 Lucius Burris; SCGEM; #5, 6 Roger Green; SCGEM; #5, 6	
John Blazekovich; Exelon; 1,2,5,6	
Al Corbet; TVA Jerry Landers; TVA Jennifer Weber; TVA Edd Forsythe; TVA	

Larry Goins; TVA Mark Creech; TVA Kathy Davis; TVA	
William Pope; Gulf Power Co; #3	
Gerald Rheault; Manitoba Hydro; #1,3,5,6	
Marc Butts; Southern Company Svcs; #1 Raymond Vice; Southern Company Svcs; #1 Dan Baisden; Southern Company Svcs; #1 Jim Griffith; Southern Company Svcs; #1 Phil Winston; Georgia Power Company; #3 Jim Viikinsalo; Southern Company Svcs; #1 Mike Miller; Southern Company Svcs; #1 Monroe Landrum; Southern Company Svcs; #1 Gwen Frazier; Southern Company Svcs; #1 Steve Williamson; Southern Company Svcs; #1 Rod Hardiman; Southern Company Svcs; #1 Jonathan Glidewell; Southern Company Svcs; 1 Dan Richards; Southern Company Svcs; #1 Mike Hardy; Southern Company Svcs; #1 David Majors; Georgia Power Company; #3	
'No' Responses	
Karl Kohlrus; City Water, Light & Power; # 5	The minimum voltage of a Bulk Electric System should be 100 KV
Most commenters agreed that 35 kV is too low. The revised definition uses 100 kV or higher as a threshold.	
Carter Edge; SEPA ; #4 & 5 William Gaither; SC Public Svc Auth; #1 Ken Skroback; AL Elec Coop ; #1 Roger Brand; Muni Elec Auth of GA; #1 Phil Creech; Progress Energy - Carolinas; #1 Gene Delk; SCE&G; #1 Al McMeekin; SCE&G; #1 Randy Hunt; Dominion – VA Pwr; #1 Doug Newbauer; GA System Ops; #1 Mike Clements; TVA; #1 Don Reichenbach; Duke Energy; #1 Lynna Estep; SERC; #2 Dan Kay; S Mississippi Elec Pwr Assoc; #1 Matt Ansley; Southern Company; #1 Uma Gangadharan; Entergy; #1	We believe that 35 kV is too low for the Bulk Electric System. A more appropriate level would be 100 kV and above.
Most commenters agreed that 35 kV is too low. The revised definition uses 100 kV or higher as a threshold.	
Lee Xanthakos; SCE&G; #1	I agree with OPS that 35kv is too low. This definition should define the level as 100 kV and above.
Most commenters agreed that 35 kV is too low. The revised definition uses 100 kV or higher as a	

threshold.	
Ken Githens; Allegheny Energy 5	We feel that this definition could be interpreted as including all facilities at and above 35kV whether they are transmission or not. The Bulk Electric System should be defined as 100kV and above network transmission system or lower voltage facilities that pass the FERC seven factor test.
Most commenters agreed that 35 kV is too low. The revised definition uses 100 kV or higher as a threshold. The FERC seven factor test which you provided to the SDT is a good guideline for distinguishing between distribution systems and systems that are other than distribution. The SDT will pass this recommendation on to the other SDT's that might be able to use the seven factor test. (1) Local distribution facilities are normally in close proximity to retail customers. (2) Local distribution facilities are primarily radial in character. (3) Power flows into local distribution systems; it rarely, if ever, flows out. (4) When power enters a local distribution system, it is not reconsigned or transported on to some other market. (5) Power entering a local distribution system is consumed in a comparatively restricted geographical area. (6) Meters are based at the transmission/local distribution interface to measure flows into the local distribution system. (7) Local distribution systems will be of reduced voltage.	
Raj Rana; AEP; 1,3,5,6	35 kV is too low for inclusion in the bulk electric system definition. The rest of this definition is less descriptive than the current definition in the NERC Operating Manual and contradicts the definition used in the NERC Planning Standards since 1995. The current definition in the NERC Planning Standards should be used as a starting point. Also, any definition of the Bulk Electric System should include the concept that 'networked' facilities (as opposed to radial) make up the BES and generally operated at voltages 100 kV or greater. The definition of the BES should not confuse FERC accounting rules/definitions with the functionality of the facilities themselves.
Most commenters agreed that 35 kV is too low. The revised definition uses 100 kV or higher as a threshold. Note that the documents called, "Terms Used in Planning Standards" that was approved by the NERC BOT on Feb 20, 2002 and the document called, "Additional Terms and their Definitions as Used in the NERC Planning Standards" that was approved by the NERC BOT on June 14, 2002 did not include a definition for the term, 'Bulk Electric System". A different commenter submitted a comment indicating that there is a definition of Bulk Electric System embedded in the Introduction to the Planning Standards, dated July 1997. Had the SDT been aware of its existence, the SDT would have used this definition since it would have been the most recently approved NERC definition. The definition provided in the Introduction to the NERC Planning Standards is provided here. Note that this definition would not meet your needs of including a distinction between radial and networked facilities. **Bulk Electric System:** The bulk electric system is a term commonly applied to that portion of an electric utility system, which encompasses the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. The following definition is from the NERC Glossary of Terms, approved by the NERC EC and OC on July 16, 1996 and is the exact definition the IROL SDT posted with the 2nd and 3rd versions of this standard:	

Bulk Electric System: A term commonly applied to the portion of an electric utility system that encompasses the electrical generation resources and bulk transmission system. The SDT adopted the definition of Bulk Electric System that was used in the Introduction to the Planning Standards, but added a sentence to the end of the definition to clarify that radial transmission lines are not considered part of the bulk electric system. This change supports your suggestions.	
Patti Metro; FRCC; #2 Linda Campbell ;FRCC ;#2 Steve Wallace; Seminole Electric Coop ;#4 Amy Long; Lakeland Electric; #1 Richard Gilbert; Lakeland Electric; #3 Ron Donahey; Tampa Electric Company; #3 Beth Young; Tampa Electric Company ;#3 Roger Hunnicutt ; Gainesville Reg Utl; #5 Roger Westphal ;City of Gainesville; #3 Greg Woessner ;Kissimmee Utility Auth;#3 Ben Sharma ;Kissimmee Utility Auth;#3 Garry Baker; JEA ;#1 Ed DeVarona; Florida Power & Light Co. ;#1 Preston Pierce; Progress Energy Florida ;#1 Bob Remley; Clay Electric Cooperative; #4 Joe Krupar; FMPA; #3 Paul Elwing; Lakeland Electric; #5 Joe Roos; Ocala Electric Utility ;#3	Bulk Electric System: A term commonly applied to the portion of an electric utility system that encompasses the interconnected electrical generation resources and the interconnected high voltage transmission system above 100 kV. Radial transmission lines serving only load with one transmission source are not included in this definition.
Most commenters agreed that 35 kV is too low. The revised definition uses 100 kV or higher as a threshold and includes your suggested sentence about excluding radial transmission lines..	
William Smith; Allegheny Power; #1	We feel that this definition could be interpreted as including all facilities at and above 35kV whether they are transmission or not. The Bulk Electric System should be defined as 100kV and above network transmission system or lower voltage facilities that pass the FERC seven factor test.
Most commenters agreed that 35 kV is too low. The revised definition uses 100 kV or higher as a threshold and includes a sentence to clarify that radial transmission lines serving only load with one transmission source are not considered part of the bulk electric system. The FERC seven factor test includes the following: (1) Local distribution facilities are normally in close proximity to retail customers. (2) Local distribution facilities are primarily radial in character. (3) Power flows into local distribution systems; it rarely, if ever, flows out. (4) When power enters a local distribution system, it is not reconsigned or transported on to some other market. (5) Power entering a local distribution system is consumed in a comparatively restricted geographical area. (6) Meters are based at the transmission/local distribution interface to measure flows into the local distribution system. (7) Local distribution systems will be of reduced voltage. It appears that the seven factor test would be most useful in identifying facilities that should be considered ‘distribution’, rather than for identifying facilities that should be considered ‘bulk’. If rephrased, the concept of the FERC seven factor test could be useful in distinguishing between	

distribution and non-distribution.	
Ed Davis; Entergy Services; #1	The definition of Bulk Electric System seems to be hard to pin down. We suggest: Bulk Electric System: A term commonly applied to the portion of an electric utility system that encompasses the electrical high voltage transmission facilities above 100 kV and associated equipment, or as approved in a tariff filed with FERC, and generation resources connected to that transmission system.
Most commenters agreed that 35 kV is too low. The revised definition uses 100 kV or higher as a threshold. Several commenters objected to inclusion of any reference to a 'tariff' in the definition. Note that the SDT revised the standard so this term is no longer used, and the term has been removed from the list of defined terms associated with this standard.	
John Swanson;NPDD;2 Darrick Moe;WAPA;2 Lloyd Linke;WAPA;2 Paul Koskela; MP; 2 Larry Larson; OTP; 2 Dick Pursley; GRE; 2 Martin Trence; XCEL; 2 Todd Gosnell; OPPD; 2 Robert Coish; MH; 2 Joe Knight; MAPPCOR; 2 Tom Mielnik; MEC; 2 Dave Jacobson; MH; 2 Delyn Helm; GRE; 2 Jason Weiers; OTP; 2 Dennis Kimm; MEC; 2	Portions of the transmission system that are operated radially below 100 kV should be excluded to avoid excessive data reporting that may be required for other standards that use this definition.
Agreed. The revised definition uses 100 kV or higher as a threshold and includes a sentence to clarify that radial transmission lines serving only load with one transmission source are not considered part of the bulk electric system.	
Dan Boezio; AEP; #1 Ron Ciesiel; SPP; #2 Bob Cochran; SPS; #1 Mike Gammon; KCP&L; #1 Allen Klassen; Westar; #1 Peter Kuebeck; OG&E; #1 Mike Stafford; GRDA; #1 Robert Rhodes; SPP; #2 Scott Moore; AEP; #1	Reference to a voltage class is fine, but the correct voltage class should be referenced. In the Introduction Section of the NERC Planning Standards the definition of Bulk Electric System contains 100 kV as the qualifier. Shouldn't this definition be consistent with this long-standing definition?
The SDT would have used this definition if they had been aware of its existence. Unfortunately, when the SDT did a 'search' with the NERC search engine of the NERC web site, seeking existing NERC defined terms, the search did not link to the definition of Bulk Electric System that appears in the Planning Standards. The definition in the Planning Standards is embedded in the document's Introduction, and isn't included in the official list of defined terms in either the "Terms Used in Planning Standards" that was approved by the NERC BOT on Feb 20, 2002 or the document called, "Additional Terms and their Definitions as Used in the NERC Planning Standards" that was approved by the NERC	

<table>
<tr><td colspan="2">BOT on June 14, 2002.
The revised definition starts with the definition of Bulk Electric System from the Introduction to the Planning Standards and includes a sentence to clarify that radial transmission lines serving only load with one transmission source are not considered part of the bulk electric system.</td></tr>
<tr><td>Dale McMaster; AESO; #2
Ed Riley; CAISO; #2
Sam Jones; ERCOT; #2
Don Tench ; IMO; #2
Dave LaPlante; ISO_NE; #2
William Phillips; MISO; #2
Karl Tammar; NYISO; #2
Bruce Balmat; PJM; #2
Carl Monroe; SPP ; #2</td><td>Please drop the parenthetical expression – we would ask NERC and the industry to develop "standard" definitions of the common terms to be used by the all standard drafting teams.</td></tr>
<tr><td colspan="2">The SDT adopted the definition of Bulk Electric System that was used in the Introduction to the Planning Standards, and added a qualifying sentence to indicate that radial transmission lines serving only load with one transmission source are not considered part of the bulk electric system.
Because the SDT's are working in parallel, and because the standards are being developed in a serial rather than sequential order, it is not practical to have a pre-defined set of terms for use by all SDT's. The SDT's have advised the SAC of the need to ensure coordination of terminology and definitions between SDT's.</td></tr>
<tr><td>Anita Lee; AESO; #2</td><td>The AESO supports comments of the Standards Review Committee of the ISO/RTO Council.</td></tr>
<tr><td colspan="2">Please see the response provided to the ISO/RTO members.</td></tr>
<tr><td>Chifong Thomas; PG&E; #1
Glenn Rounds; PG&E; #1
Ben Morris; PG&E; #1</td><td>Please delete the parenthesis and add, "the operation of which would impact the operation of the Interconnection System of the Region, or as approved by a tariff filed with FERC". The operation of a Bulk Electric System should have impacts on the operation of the Regional Interconnected System. In most systems in WECC, 35 kV would be considered distribution voltage.</td></tr>
<tr><td colspan="2">The SDT adopted the definition of Bulk Electric System that was used in the Introduction to the Planning Standards, and added a qualifying sentence to indicate that radial transmission lines serving only load with one transmission source are not considered part of the bulk electric system. This definition uses 100kV as a threshold for bulk power.
Most commenters agreed with you that 35 kV was too low.</td></tr>
<tr><td>James Murphy; BPAT;#1
Mike Viles; BPAT; #1
Richard Spence; BPAT; #1
Don Watkins; BPAT; #1
Don Gold; BPAT; #1
Marv Landauer; BPAT; #1</td><td>The (above 35 kV or as approved in a tariff filed with FERC) should be changed to (200kV and above or as determined by region). This will avoid including many lines that are not part of the Bulk Electric System, but if they are significant the Regions can add them into consideration for IROL's.</td></tr>
<tr><td colspan="2">The SDT adopted the definition of Bulk Electric System that was used in the Introduction to the Planning Standards, and added a qualifying sentence to indicate that radial transmission lines serving only load with one transmission source are not considered part of the bulk electric system. This definition uses 100kV as a threshold for bulk power.
Most commenters agreed with you that 35 kV was too low. The revised definition uses 100kV as a threshold.</td></tr>
</table>

Marv Landauer; BPA; #1	This definition, since it relates to IROLs, should not be tied to voltage, rather it should be based on function. I suggest the following: "An individual electric system facility is considered part of the Bulk Electric System if the availability of that element (whether it is in or out) impacts the capacity of an SOL or IROL."
The SDT adopted the definition of Bulk Electric System that was used in the Introduction to the Planning Standards, and added a qualifying sentence to indicate that radial transmission lines serving only load with one transmission source are not considered part of the bulk electric system. This definition uses 100kV as a threshold for bulk power. While this change does not support your specific suggestion, the change conforms to the majority of the comments received.	
Ralph Rufrano; NYPA; #1 David Kiguel; Hydro One Networks Inc.; #1 Roger Champagne; H-Q TransÉnergie; #1 Greg Campoli; New York ISO (NYISO); #2 Peter Lebro; National Grid; #1 Kathleen Goodman; ISO-NE; #2 Dan Stosick; ISO-NE;#2 Al Adamson; NYSRC;#2 Khagan Khan; The IMO Ontario; #2 Brian Hogue; NPCC;#2 Guy Zito; NPCC;#2 Lawrence Hochberg; NYSRC; #2	This definition should be reliability-"performance based" and references to tariffs should be removed. The existing NPCC Definition for its Bulk Power System is; "The interconnected electrical systems within northeastern North America comprising generation and transmission facilities on which faults or disturbances can have significant adverse impact outside of the local area. Local areas are determined by the Council members." Furthermore NPCC CP9 members listed feel that in no instance should a BES criteria encompass facilities at voltage levels less than 115 kV and strongly urges the eventual adoption of a "performance based" definition not a "voltage based" one.
The SDT adopted the definition of Bulk Electric System that was used in the Introduction to the Planning Standards, and added a qualifying sentence to indicate that radial transmission lines serving only load with one transmission source are not considered part of the bulk electric system. This definition uses 100kV as a threshold for bulk power.	
Greg Campoli; NYISO; #2 James Castle; NYISO ;#2 John Ravalli; NYISO; #2 Karl Tammar; NYISO; #2 Robert Waldele; NYISO; #2 Michael Calimano; NYISO; #2	This definition should be reliability-"performance based" and references to tariffs should be removed. For reference, we offer the existing NPCC Definition for its Bulk Power System is; "The interconnected electrical systems within northeastern North America comprising generation and transmission facilities on which faults or disturbances can have significant adverse impact outside of the local area. Local areas are determined by the Council members." The NYISO strongly urges the eventual adoption of a "performance based" definition not a "voltage based" one.
The SDT adopted the definition of Bulk Electric System that was used in the Introduction to the Planning Standards, and added a qualifying sentence to indicate that radial transmission lines serving only load with one transmission source are not considered part of the bulk electric system. This definition uses 100kV as a threshold for bulk power.	
Khaqan Khan; IMO; #2	We feel that the definition of BES should not be tied up with FERC tariff. It should be upto the Reliability Authority to determine whether the facilities are impactive to the neighbors or not.

	It is suggested to remove the definition-item within parenthesis. Resulting definition is as below: "A term commonly applied to the portion of an electric utility system that encompasses the electrical generation resources and high voltage transmission system"
The SDT adopted the definition of Bulk Electric System that was used in the Introduction to the Planning Standards, and added a qualifying sentence to indicate that radial transmission lines serving only load with one transmission source are not considered part of the bulk electric system. This definition uses 100kV as a threshold for bulk power.	
Kathleen Goodman; ISO-NE; #2	The BES should be defined based on performance (impact) on the power system, not a pre-defined voltage level. Suggest using a definition similar to NPCC "BULK POWER SYSTEM – The interconnected electrical systems within northeastern North America comprising generation and transmission facilities on which faults or disturbances have a significant adverse impact outside of the local area" (i.e. Control Area). If a pre-defined voltage level is necessary, at a minimum, it should not be less than a 115 kV threshold.
The SDT adopted the definition of Bulk Electric System that was used in the Introduction to the Planning Standards, and added a qualifying sentence to indicate that radial transmission lines serving only load with one transmission source are not considered part of the bulk electric system. This definition uses 100kV as a threshold for bulk power.	
Jalal Babik; Dominion VA Power; #1 Craig Crider; Dominion VA Power; #1 Jack Kerr; Dominion VA Power; #1 Bill Thompson; Dominion VA Power; #1	By this definition, a Bulk Electric System could be as small as the transmission system covered by the OATT of the smallest "electric utility". This interpretation is not consistent with the usage of the term in the definition of IROL that appears in the revised Policy 9 currently being balloted by the Standing Committees.
The SDT adopted the definition of Bulk Electric System that was used in the Introduction to the Planning Standards, and added a qualifying sentence to indicate that radial transmission lines serving only load with one transmission source are not considered part of the bulk electric system. This definition uses 100kV as a threshold for bulk power.	
Alan Gale; City of Tallahassee; #5 Rusty Foster; City of Tallahassee; #3	Suggested Definition: Bulk Electric System: A term commonly applied to the portion of the electric system used in the transport of power in inter-utility transactions.
The SDT adopted the definition of Bulk Electric System that was used in the Introduction to the Planning Standards, and added a qualifying sentence to indicate that radial transmission lines serving only load with one transmission source are not considered part of the bulk electric system. This definition uses 100kV as a threshold for bulk power.	
Richard Kafka, Pepco #3	While FERC may approve nearly any voltage level as "transmission," that does not qualify the facility as part of the bulk electric system. Regional practices and expected power flows con be used to distinguish between bulk and local electric facilities. The Regional Reliability Council should have authority to part of the bulk electric system if the facility owner does not voluntarily consider a facility to be such.
The SDT adopted the definition of Bulk Electric System that was used in the Introduction to the Planning Standards, and added a qualifying sentence to indicate that radial transmission lines serving only load	

with one transmission source are not considered part of the bulk electric system. This definition uses 100kV as a threshold for bulk power.	
John Horakh; MAAC; #2	The parenthetical portion of the definition is too inclusive in specifying what makes up the "high voltage transmission system". It requires all lines "above 35 kV or as approved in a tariff filed with FERC" to be included as part of the Bulk Electric System. Many lines that would fit this specification are indeed "transmission" rather than "distribution", but they may not be part of the BULK transmission, i.e., the transmission that affects the overall reliability of the interconnected systems. Such "non-bulk" transmission lines could be called "subtransmission" or "underlying transmission" or "local transmission". Many lines above 35 kV fall into this "non-bulk" category. Also, FERC tariff filings may limit lines to voltage levels above 35 kV, but may still contain many "non-bulk" transmission lines in order that such lines may receive proper regulatory treatment. In those cases, an entity would have no choice but to consider those "non-bulk" lines as part of the Bulk Electric System. The definition should be corrected by either of the following: a. Delete the parenthetical portion, OR, b. Change the parenthetical portion to the following – "(above 35 kV or as defined in a publicly available document)". This would still allow the FERC filing to be used to limit and define the Bulk Electric System, IF APPROPRIATE. If further limiting is needed, this would allow an entity to produce, and make publicly available, another document to define the Bulk Electric System.
The SDT adopted the definition of Bulk Electric System that was used in the Introduction to the Planning Standards, and added a qualifying sentence to indicate that radial transmission lines serving only load with one transmission source are not considered part of the bulk electric system. This definition uses 100kV as a threshold for bulk power.	
Ed Riley; CA-ISO; #2	Please drop the parenthetical expression as it is not applicable in Canada – we would ask NERC and the industry to develop "standard" definitions of the common terms to be used by the all standard-drafting teams. Could we use the definition of transmission out of FERC Order 888?
The SDT adopted the definition of Bulk Electric System that was used in the Introduction to the Planning Standards, and added a qualifying sentence to indicate that radial transmission lines serving only load with one transmission source are not considered part of the bulk electric system. This definition uses 100kV as a threshold for bulk power. Because the SDT's are working in parallel, and because the standards are being developed in a serial rather than sequential order, it is not practical to have a pre-defined set of terms for use by all SDT's. The SDT's have advised the SAC of the need to ensure coordination of terminology and definitions between SDT's.	

2. Cascading Outage

Several balloters indicated that they didn't know if a studied event would meet the old definition of a cascading outage. The SDT adopted criteria currently used by the Department of Energy as the threshold for disturbance reporting. DOE uses, "Uncontrolled loss of 300 MW or more of firm system loads for more than 15 minutes from a single incident" as one of its thresholds for reporting disturbances.

If a study shows that exceeding an SOL will result in the uncontrolled successive loss of 300 MW or more of networked system load for 15 minutes or more — then that SOL is considered an IROL. Do you agree with the revised definition?

> **Original Definition: Cascading Outages:** The uncontrolled successive loss of system elements triggered by an incident at any location that results in the loss of 300 MW or more of networked system load for a minimum of 15 minutes.

Summary Consideration: Because we've agreed to delay balloting this IROL standard until after the Determine Facility Ratings (DFR) standard has been balloted, the IROL SDT has transferred responsibility for refining the definition of Cascading Outages to the DFR SDT. All comments on the draft definition have been forwarded to the Determine Facility Ratings SDT for consideration by that SDT.

'Yes' Responses	
William Pope; Gulf Power Co; #3 Marc Butts; Southern Company Svcs; #1 Raymond Vice; Southern Company Svcs; #1 Dan Baisden; Southern Company Svcs; #1 Jim Griffith; Southern Company Svcs; #1 Phil Winston; Georgia Power Company; #3 Jim Viikinsalo; Southern Company Svcs; #1 Mike Miller; Southern Company Svcs; #1 Monroe Landrum; Southern Company Svcs; #1 Gwen Frazier; Southern Company Svcs; #1 Steve Williamson; Southern Company Svcs; #1 Rod Hardiman; Southern Company Svcs; #1 Jonathan Glidewell; Southern Company Svcs; 1 Dan Richards; Southern Company Svcs; #1 Mike Hardy; Southern Company Svcs; #1 David Majors; Georgia Power Company; #3	We generally agree with the new definition. However, we want to point out that in some very large systems, such as Southern Company, that include large metropolitan areas there are substations that serve geographic areas with very large loads. There can be cases in such substations where a fault occurs and the breaker fails to operate. In this breaker-failure scenario, large loads can be dropped for a short period of time in a controlled fashion in order to prevent cascading outages or instability. Our concern relates to reporting this as a 'wide area impact' violation simply because it produces a loss of 300 MW, while being confined to a single substation or possibly even one or two large factories on a particular bus. We are aware that the cascading outage definition is 'magnitude and time' sensitive but we believe it should be tailored to allow rational management of local area outages of large substations if they are managed in a controlled manner.
Note that the Determine Facility Ratings SDT (DFR SDT) has taken over the task of trying to get industry consensus on the definition of Cascading Outages. The DFR SDT is adding the phrase, 'unplanned' to the definition, and removing the reference to a specific # of MW. These changes look like they support your position.	
Lee Xanthakos; SCE&G; #1	I like this definition. Although 300 is an arbitrary number (why not 500 for example),I like the fact that it is quantitative and easily measurable – after the fact at
Note that the Determine Facility Ratings SDT (DFR SDT) has taken over the task of trying to get industry consensus on the definition of Cascading Outages. The DFR SDT, and most industry commenters, do not support the inclusion of any # of MW in the definition of Cascading Outages.	
Gerald Rheault; Manitoba Hydro; #1,3,5,6	In concept this is OK, however, in current practice,

	simulation methods do not usually stress the system to the point of loss of load. Some of the mechanisms that might result in loss of load, such as collapse of an isolated island, may not be demonstrated with current modeling techniques. Current study techniques simulate only single contingency. Actual events which result in loss of 300 MW or more of networked system load are usually due to several contingencies occurring prior to system adjustment. There are too many possible scenarios to identify with current study resources. Such an approach is not recommended. Therefore the proposed criterion may not be practical to apply in studies.
Note that the Determine Facility Ratings SDT (DFR SDT) has taken over the task of trying to get industry consensus on the definition of Cascading Outages. Also note that the DFR SDT asked the industry if there was a need to study credible multiple contingencies and the industry commenters indicated this is done today, and there is a need to continue to study these. Therefore, the assumption that most study techniques are limited to single contingency scenarios may not be correct.	
Patti Metro; FRCC; #2 Linda Campbell ;FRCC ;#2 Steve Wallace; Seminole Electric Coop ;#4 Amy Long; Lakeland Electric; #1 Richard Gilbert; Lakeland Electric; #3 Ron Donahey; Tampa Electric Company; #3 Beth Young; Tampa Electric Company ;#3 Roger Hunnicutt ; Gainesville Reg Utl; #5 Roger Westphal ;City of Gainesville; #3 Greg Woessner ;Kissimmee Utility Auth;#3 Ben Sharma ;Kissimmee Utility Auth;#3 Garry Baker; JEA ;#1 Ed DeVarona; Florida Power & Light Co. ;#1 Preston Pierce; Progress Energy Florida ;#1 Bob Remley; Clay Electric Cooperative; #4 Joe Krupar; FMPA; #3 Paul Elwing; Lakeland Electric; #5 Joe Roos; Ocala Electric Utility ;#3	
Mark Fidrych; WAPA; #1	
Karl Kohlrus; City Water, Light & Power; # 5	
Roman Carter; SCGEM; #5, 6 Joel Dison; SCGEM; #5, 6 Tony Reed; SCGEM; #5, 6 Lloyd Barnes; SCGEM; #5, 6 Clifford Shepard; SCGEM; #5, 6 Lucius Burris; SCGEM; #5, 6	

Roger Green; SCGEM; #5, 6	
'No' Responses	
John Swanson;NPDD;2 Darrick Moe;WAPA;2 Lloyd Linke;WAPA;2 Paul Koskela; MP; 2 Larry Larson; OTP; 2 Dick Pursley; GRE; 2 Martin Trence; XCEL; 2 Todd Gosnell; OPPD; 2 Robert Coish; MH; 2 Joe Knight; MAPPCOR; 2 Tom Mielnik; MEC; 2 Dave Jacobson; MH; 2 Delyn Helm; GRE; 2 Jason Weiers; OTP; 2 Dennis Kimm; MEC; 2	The definitions of SOL, IROL, Local Area and Widespread area used in the NERC Operating Limit Definitions and Reporting document approved at the March 23 NERC OC meeting should be used instead of incorporating DOE definitions.
Although these terms were accepted by the OC, they did not receive the same level of industry debate that the new reliability standards process requires. In addition, the OLDTF's definitions do not match the definitions included in the Compliance Templates adopted by the NERC BOT.	
John Blazekovich; Exelon; 1,2,5,6	This definition should be consistent with the definition used by the Determine Facility Ratings, System Operating Limits & Transfer Capability SDT.
Agreed. Because we've agreed to delay balloting this IROL standard until after the Determine Facility Ratings (DFR) standard has been balloted, the IROL SDT has transferred responsibility for refining the definition of Cascading Outages to the DFR SDT.	
Raj Rana; AEP; 1,3,5,6	The proposed definition is unclear. Why the need to include load impacted and time requirements into the Cascading Outage definition? Is a 250 MW loss of load for 24 hours a cascading event? How about 1000 MW for 10 Minutes? The key thought of a Cascading Outage is that it is Unplanned and Uncontrolled outage over a wider area. The Facility Rating SDT is using as a definition of Cascading Outage is "The uncontrolled and unplanned successive loss of system elements triggered by an incident at any location." Is it really necessary to define cascading outage, if we can define as above when an SOL is to be considered an IROL? To be a cascading outage, multiple system elements must be involved and a series of uncontrolled events occur.
The SDT was trying to move the industry towards consensus on this term – in prior postings, industry commenters indicated a need to have objective elements that each RA could use to determine if an SOL should be classified as an IROL. The SDT was trying to add those objective elements. Note that because the IROL SDT has agreed to delay balloting this IROL standard until after the Determine Facility Ratings (DFR) standard has been balloted, the IROL SDT has transferred responsibility for refining the definition of Cascading Outages to the DFR SDT. Note that we've	

forwarded the comments on this definition to the DFR SDT and asked them to consider including the 'wide area' concept in their definition.	
James Murphy; BPAT;#1 Mike Viles; BPAT; #1 Richard Spence; BPAT; #1 Don Watkins; BPAT; #1 Don Gold; BPAT; #1 Marv Landauer; BPAT; #1	There is a concern with some at BPA that the Definition of Cascading Outages will affect other standards. Specifically the use of "300 MW or more of networked system load for a minimum of 15 minutes" will not work with other standards. It has been suggested to use the current definition for Cascading Outages be used in the IROL definition.
Note that because the IROL SDT has agreed to delay balloting this IROL standard until after the Determine Facility Ratings (DFR) standard has been balloted, the IROL SDT has transferred responsibility for refining the definition of Cascading Outages to the DFR SDT. Note that we've forwarded the comments on this definition to the DFR SDT and asked them to consider these comments in making their revisions to their definitions.	
Michael Zahorik; ATC; #1	300 mw is to low a value. There are instances that this amount of load can be lost and there are no network implications.
Agreed. Most commenters indicated that 300 MW was too low a threshold value.	
Dale McMaster; AESO; #2 Ed Riley; CAISO; #2 Sam Jones; ERCOT; #2 Don Tench ; IMO; #2 Dave LaPlante; ISO_NE; #2 William Phillips; MISO; #2 Karl Tammar; NYISO; #2 Bruce Balmat; PJM; #2 Carl Monroe; SPP ; #2	The definition should read as follows: The uncontrolled successive loss of Bulk Power Transmission elements that propagate beyond a balancing area's boundaries.
Because the Functional Model assigns the RA and TOP responsibility for monitoring and operating within limits, the SDT was trying to find a definition that would align with the RA and TOP, rather than the Balancing Authority. In trying to determine if its limit will impact entities outside its boundaries, the TOP will be looking at its own boundaries, not those of the Balancing Authority.	
Chifong Thomas; PG&E; #1 Glenn Rounds; PG&E; #1 Ben Morris; PG&E; #1	Loss of 300 MW of load is not a measure or indication of cascading. Please change the definition to read, "The uncontrolled and unplanned successive loss of system elements triggered by an incident at any location. Cascading results in widespread electric service interruption, which cannot be restrained from sequentially spreading beyond an area predetermined by appropriate studies".
Note that because the IROL SDT has agreed to delay balloting this IROL standard until after the Determine Facility Ratings (DFR) standard has been balloted, the IROL SDT has transferred responsibility for refining the definition of Cascading Outages to the DFR SDT. Note that we've forwarded the comments on this definition to the DFR SDT and asked them to consider these comments in making their revisions to their definitions.	
Khaqan Khan; IMO; #2	It is not the threshold of 300 MW that qualifies an incident to cause a cascading outage. An option is to use a definition: "The uncontrolled successive loss of Bulk Electric System elements that propagate beyond a defined area (balancing area's) boundaries"

<table>
<tr><td colspan="2">Because the Functional Model assigns the RA and TOP responsibility for monitoring and operating within limits, the SDT was trying to find a definition that would align with the RA and TOP, rather than the Balancing Authority. In trying to determine if its limit will impact entities outside its boundaries, the TOP will be looking at its own boundaries, not those of the Balancing Authority.</td></tr>
<tr><td>Kathleen Goodman; ISO-NE; #2</td><td>This does not appropriately indicate that the losses are “cascading,” not localized, not BES, etc. Agreed with the concept of “uncontrolled successive loss,” but do not agree that the 300 MW is an appropriate measure. The loss of 300 MW of load has nothing to do with cascading or uncontrolled successive losses. You may lose over 300 MW of load, but it poses no risk to the interconnection. We believe that the standard should be that the cascading outages propagate beyond the local area (i.e. Control Area). Specific, hard, concrete examples about how IROLs are calculated, including specific contingency pair examples for things like thermal limits, are needed such that the whole industry can understand what an IROL is.</td></tr>
<tr><td colspan="2">Because the Functional Model assigns the RA and TOP responsibility for monitoring and operating within limits, and for establishing those limits for use in real-time operations, the SDT was trying to find a definition that would align with the RA and TOP, rather than the Balancing Authority (or control area). In trying to determine if its limit will impact entities outside its boundaries, the TOP will be looking at its own boundaries, not those of the Balancing Authority or Control Area.

The Determine Facility Ratings, System Operating Limits and Transfer Capabilities Standard will require that the RA and PA have a methodology for developing SOL's that includes identification of which SOLs are also IROLs. The subset of SOL’s that are to be considered IROLs are those that, if exceeded, could cause cascading outages, uncontrolled separation or instability.</td></tr>
<tr><td>R. Peter Mackin; TRANC; #1</td><td>I would suggest the definition be changed to: The uncontrolled or unplanned successive loss of system elements triggered by an incident at any location. Cascading Outages result in Wide-Area Impacts, which cannot be restrained from sequentially spreading beyond an area predetermined by appropriate studies</td></tr>
<tr><td colspan="2">Note that because the IROL SDT has agreed to delay balloting this IROL standard until after the Determine Facility Ratings (DFR) standard has been balloted, the IROL SDT has transferred responsibility for refining the definition of Cascading Outages to the DFR SDT. Note that we’ve forwarded the comments on this definition to the DFR SDT and asked them to consider these comments in making their revisions to their definitions.</td></tr>
<tr><td>Ralph Rufrano; NYPA; #1
David Kiguel; Hydro One Networks Inc.; #1
Roger Champagne; H-Q TransÉnergie; #1
Greg Campoli; New York ISO (NYISO); #2
Peter Lebro; National Grid; #1
Kathleen Goodman; ISO-NE; #2
Dan Stosick; ISO-NE;#2
Al Adamson; NYSRC;#2
Khagan Khan; The IMO Ontario; #2
Brian Hogue; NPCC;#2</td><td>An event characterized by one or more of the following phenomena:
the loss of power system stability
cascading outages of circuits
oscillations; abnormal ranges of frequency or voltage or both.

NPCC participating members of CP9 (NYSRC) feel it is not the threshold of 300 MW that qualifies an incident to be classified as a cascading outage. The loss of 300 MW of load may have nothing to do with</td></tr>
</table>

<table>
<tr><td>Guy Zito; NPCC;#2
Lawrence Hochberg; NYSRC; #2</td><td>cascading or uncontrolled successive losses, 300 MW of load may be lost under certain conditions, but it doesn't necessarily pose a risk to the interconnection. We believe that the standard specify that the cascading outages not propagate beyond the local area (i.e. Control Area).Moreover, the definition of "Cascading Outage" as outlined in Standard 200 is different from that defined in Standard 600 (Develop Facility Ratings, …). It is recommended to follow a common definition as given in Std 600, including a minor modification, as follows. i.e."
"The uncontrolled successive loss of Bulk Electric System elements that propogate beyond a defined area (Balancing Area's) boundaries."
In addition, specific examples about how IROLs are calculated, including specific contingency pair examples for things like thermal limits, are needed such that the whole industry can understand what an IROL is.</td></tr>
<tr><td colspan="2">Most commenters indicated that 300 MW was too low a threshold value.
Because the Functional Model assigns the RA and TOP responsibility for monitoring and operating within limits, and for establishing those limits for use in real-time operations, the SDT was trying to find a definition that would align with the RA and TOP, rather than the Balancing Authority (or control area). In trying to determine if its limit will impact entities outside its boundaries, the TOP will be looking at its own boundaries, not those of the Balancing Authority or Control Area.
The Determine Facility Ratings, System Operating Limits and Transfer Capabilities Standard (DFR Standard) will require that the RA and PA have a methodology for developing SOL's. The DFR Standard will also require that the SOL development methodology include the process used to identify the subset of SOL's that are also IROLs. The subset of SOL's that are to be considered IROLs are those that, if exceeded, could cause cascading outages, uncontrolled separation or instability. The contingencies used in identifying IROLs are the same contingencies used in developing SOLs, and are outlined in Standard 603.</td></tr>
<tr><td>Greg Campoli; NYISO; #2
James Castle; NYISO ;#2
John Ravalli; NYISO; #2
Karl Tammar; NYISO; #2
Robert Waldele; NYISO; #2
Michael Calimano; NYISO; #2</td><td>The NYISO believes that the standard should specify that the cascading outages not propagate beyond the local area (i.e. Control Area or balancing area). A threshold of 300 MW does not qualify an incident to be classified as a cascading outage. The loss of 300 MW of load may have nothing to do with cascading or uncontrolled successive losses, 300 MW of load may be lost under certain conditions, but it doesn't necessarily pose a risk to the interconnection. We note that the definition of "Cascading Outage" as outlined in Standard 200 is different from that defined in Standard 600 (Develop Facility Ratings,). We recommend adopting a common definition as given in Std 600, including a minor modification, as follows. i.e."
"The uncontrolled successive loss of Bulk Electric System elements that propogate beyond a defined area (Balancing Area's) boundaries."
In addition, specific examples about how IROLs are calculated, including specific contingency pair examples for things like thermal limits, are needed</td></tr>
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	such that the whole industry can understand what an IROL is.
Because the Functional Model assigns the RA and TOP responsibility for monitoring and operating within limits, and for establishing those limits for use in real-time operations, the SDT was trying to find a definition that would align with the RA and TOP, rather than the Balancing Authority (or control area). In trying to determine if its limit will impact entities outside its boundaries, the TOP will be looking at its own boundaries, not those of the Balancing Authority or Control Area. Most commenters indicated that 300 MW was too low a threshold value. The Determine Facility Ratings, System Operating Limits and Transfer Capabilities Standard (DFR Standard) will require that the RA and PA have a methodology for developing SOL's. The DFR Standard also requires that the SOL development methodology include the process used to identify the subset of SOL's that are also IROLs. The subset of SOL's that are to be considered IROLs are those that, if exceeded, could cause cascading outages, uncontrolled separation or instability.	
Jalal Babik; Dominion VA Power; #1 Craig Crider; Dominion VA Power; #1 Jack Kerr; Dominion VA Power; #1 Bill Thompson; Dominion VA Power; #1	The narrow definition may cause some issues for the operators, depending on how this standard is applied, and whether planned maintenance and a contingency becomes an issue under transfer conditions. The key will be if you can get out of the condition quickly-i.e. 30 minutes. If the cascading outages definition trickles over to the Planning side or to other Operations Standards, it could mean extra expenditures for the company. There are a number of places where double contingencies can cause large loss of load, but not cascading as defined as follows: Cascading (planning definition/old ops definition): The uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread service interruption, which cannot be restrained from sequentially spreading beyond an area predetermined by appropriate studies This definition gives much leeway. As long as you studied it, and you can tell how far the interruption spreads, it is not cascading. We could lose Northern Virginia or South Hampton Roads and still be in compliance. The loss of both 500 kV feeds to Yadkin and Fentress would drop over 300 MW.
The SDT working on the Determine Facility Ratings Standard and the SAR DT working on the Transmission Planning SAR have both indicated that the definition of cascading outages that was posted with this standard is not suitable for their use. Note that because the IROL SDT has agreed to delay balloting this IROL standard until after the Determine Facility Ratings (DFR) standard has been balloted, the IROL SDT has transferred responsibility for refining the definition of Cascading Outages to the DFR SDT. Note that we've forwarded the comments on this definition to the DFR SDT and asked them to consider these comments in making their revisions to their definitions.	

William Smith; Allegheny Power; #1 Ken Githens; Allegheny Energy 5	Determining the amount of load loss and restoration time in a pre-contingency study is not possible with the current real-time analysis tools.
Most commenters did not agree with the proposed definition. Note that because the IROL SDT has agreed to delay balloting this IROL standard until after the Determine Facility Ratings (DFR) standard has been balloted, the IROL SDT has transferred responsibility for refining the definition of Cascading Outages to the DFR SDT. Note that we've forwarded the comments on this definition to the DFR SDT and asked them to consider these comments in making their revisions to their definitions.	
Dan Boezio; AEP; #1 Ron Ciesiel; SPP; #2 Bob Cochran; SPS; #1 Mike Gammon; KCP&L; #1 Allen Klassen; Westar; #1 Peter Kuebeck; OG&E; #1 Mike Stafford; GRDA; #1 Robert Rhodes; SPP; #2 Scott Moore; AEP; #1	Using loss of load to imply a cascading event is not a logical link. If the point is to develop a limit for a reportable event, then call it a reportable event not a cascading outage. While this definition does set quantitative limits for cascading outages it doesn't really capture the link to cascading events. We would prefer the previous version of the definition, which while it was not as specific, captured the generic idea of cascading outages better. Trying to define cascading outages discretely may not be possible. Perhaps this definition is best left to the Determine Facility Ratings standard.
Most commenters did not agree with the proposed definition. Note that because the IROL SDT has agreed to delay balloting this IROL standard until after the Determine Facility Ratings (DFR) standard has been balloted, the IROL SDT has transferred responsibility for refining the definition of Cascading Outages to the DFR SDT. Note that we've forwarded the comments on this definition to the DFR SDT and asked them to consider these comments in making their revisions to their definitions.	
Carter Edge; SEPA ; #4 & 5 William Gaither; SC Public Svc Auth; #1 Ken Skroback; AL Elec Coop ; #1 Roger Brand; Muni Elec Auth of GA; #1 Phil Creech; Progress Energy - Carolinas; #1 Gene Delk; SCE&G; #1 Al McMeekin; SCE&G; #1 Randy Hunt; Dominion – VA Pwr; #1 Doug Newbauer; GA System Ops; #1 Mike Clements; TVA; #1 Don Reichenbach; Duke Energy; #1 Lynna Estep; SERC; #2	The MW amount should not determine whether it is a cascading outage. New definition proposal: The uncontrolled successive loss of networked system elements triggered by an incident at any location. In response to the second paragraph above for question 2, we do not believe that the 300 MW/15 minute criteria should be used to automatically determine IROL Violations. However, reporting requirements could be based on this criteria with after the fact analyses to determine if an actual IROL violation occurred.

Dan Kay; S Mississippi Elec Pwr Assoc; #1 Matt Ansley; Southern Company; #1 Uma Gangadharan; Entergy; #1	
Most commenters disagreed as you did with the 300 MW thresholds, and they have been removed. Note that because the IROL SDT has agreed to delay balloting this IROL standard until after the Determine Facility Ratings (DFR) standard has been balloted, the IROL SDT has transferred responsibility for refining the definition of Cascading Outages to the DFR SDT. Note that we've forwarded the comments on this definition to the DFR SDT and asked them to consider these comments in making their revisions to their definitions.	
Ed Riley; CA-ISO; #2	The definition should read as follows: The uncontrolled successive loss of Bulk Power Transmission elements that propagate beyond a balancing area's boundaries and have adverse impacts of system frequency, load served, or voltage.
Because the Functional Model assigns the RA and TOP responsibility for monitoring and operating within limits, and for establishing those limits for use in real-time operations, the SDT was trying to find a definition that would align with the RA and TOP, rather than the Balancing Authority (or control area). In trying to determine if its limit will impact entities outside its boundaries, the TOP will be looking at its own boundaries, not those of the Balancing Authority or Control Area. Most commenters indicated that 300 MW was too low a threshold value.	
Peter Burke; ATC; #1	The threshold of 300 MW is to low. While it is understandable that the DOE requires that a loss of this size should be reported as a disturbance, it should not be the threshold of a cascading outage. A suggested MW level would be somewhere between 1000 and 5000 MW. Could the group elaborate on the 15 minutes. How would an RA be able to determine if the load was going to be lost for more than 15 minutes? Consider whether an SOL, that is determined to be an IROL, go back to an SOL if an entity, through some process, stated that the load would be restored within 10 minutes.
Most commenters indicated that 300 MW was too low a threshold value. Both the references to 300 MW and 15 minutes have been removed from the standard.	
John Horakh; MAAC; #2	The definition implies that Cascading Outages ALWAYS result in 300 MW of load loss for a minimum of 15 minutes. This result is likely, but not 100% sure. The definition should be corrected by either of the following: a. End the sentence with "at any location." and delete the remainder, OR, b. Same as a. above, and add the following sentence – "Cascading Outages will likely have a Wide-Area Impact". Note that Wide-Area Impact is separately defined to include the 300 MW / 15 minute criteria.
Note that because the IROL SDT has agreed to delay balloting this IROL standard until after the Determine Facility Ratings (DFR) standard has been balloted, the IROL SDT has transferred responsibility for refining the definition of Cascading Outages to the DFR SDT. Note that we've	

forwarded the comments on this definition to the DFR SDT and asked them to consider these comments in making their revisions to their definitions.	
Richard Kafka; Pepco; #3	Add the term "or has a Wide-Area Impact."
Note that because the IROL SDT has agreed to delay balloting this IROL standard until after the Determine Facility Ratings (DFR) standard has been balloted, the IROL SDT has transferred responsibility for refining the definition of Cascading Outages to the DFR SDT. Note that we've forwarded the comments on this definition to the DFR SDT and asked them to consider these comments in making their revisions to their definitions.	
Anita Lee; AESO; #2	The AESO supports comments of the Standards Review Committee of the ISO/RTO Council.
Please review the response to the ISO/RTO Council's comments.	
Ed Davis; Entergy Services; #1	Cascading Outages is another term that is hard to define. Cascading Outage should be define in terms of the successive loss of system elements for which we suggest the definition be changed to: Cascading Outages: The uncontrolled successive loss of <u>networked</u> system elements triggered by an incident at any location that results in <u>the operation of more than 4 relays and</u> the loss ~~300 MW or more~~ of networked system load for a minimum of 15 minutes.
Most industry commenters disagreed with the thresholds (300 MW for 15 min) suggested in the last version of the standard. Note that because the IROL SDT has agreed to delay balloting this IROL standard until after the Determine Facility Ratings (DFR) standard has been balloted, the IROL SDT has transferred responsibility for refining the definition of Cascading Outages to the DFR SDT. Note that we've forwarded the comments on this definition to the DFR SDT and asked them to consider these comments in making their revisions to their definitions.	
Marv Landauer; BPA; #1	This definition might be appropriate for the definition of an IROL but it does not fit with the other uses for the term (such as in the performance table). I suggest that this definition be removed and the words from this definition moved into the definition of an IROL in place of the words "cascading outages".
Most industry commenters disagreed with the thresholds (300 MW for 15 min) suggested in the last version of the standard. Members of the Transmission Plans SAR DT and the Determine Facility Ratings SDT have indicated that the definition of Cascading Outages in the last posting of this standard will not meet their needs. Note that because the IROL SDT has agreed to delay balloting this IROL standard until after the Determine Facility Ratings (DFR) standard has been balloted, the IROL SDT has transferred responsibility for refining the definition of Cascading Outages to the DFR SDT. Note that we've forwarded the comments on this definition to the DFR SDT and asked them to consider these comments in making their revisions to their definitions.	
Other Comments	
Al Corbet; TVA Jerry Landers; TVA Jennifer Weber; TVA Edd Forsythe; TVA Larry Goins; TVA	For a large electric system that fluctuates between 15,000 MW to 29,000 MW in any given day, TVA feels that the loss of 300MW would not cause uncontrolled successive loss of system elements. We would prefer a Percentage of System Load rather than a hard number.

Mark Creech; TVA Kathy Davis; TVA	
Most industry commenters disagreed with the thresholds (300 MW for 15 min) suggested in the last version of the standard. Note that because the IROL SDT has agreed to delay balloting this IROL standard until after the Determine Facility Ratings (DFR) standard has been balloted, the IROL SDT has transferred responsibility for refining the definition of Cascading Outages to the DFR SDT. Note that we've forwarded the comments on this definition to the DFR SDT and asked them to consider these comments in making their revisions to their definitions.	

3. T_v

Several balloters indicated a preference for a definition of Tv that referenced a link to risk rather than a link to a sanction. Most balloters indicated a preference for an upper limit to Tv. Do you agree with the revised definition?

Original Definition: T_v: The maximum time that an Interconnection Reliability Operating Limit can be exceeded before the risk to the interconnection becomes greater than acceptable. T_v may not be greater than 30 minutes.

Summary Consideration: Most industry commenters supported this revision. There were some suggestions for minor changes, and these have been adopted. The SDT added the phrase, "Interconnection Reliability Operating Limit" in front of, "T_v" to clarify that the T_v being defined is just the Tv used with IROLs. This will enable the Balance Resources and Demand SDT to use the T_v concept for frequency-related limits. The SDT also replaced the word, 'may' with 'shall.'

Revised Definition: IROL T_v: The maximum time that an Interconnection Reliability Operating Limit can be exceeded before the risk to the interconnection becomes greater than acceptable. T_v ~~may~~ (shall) not be greater than 30 minutes.

Note that the requirement to identify the subset of SOLs that are IROLs was moved to the 'Determine Facility Ratings, System Operating Limits and Transfer Capabilities Standard'. The definition of IROL T_v was modified as noted above to conform to the industry's suggestions for improvements, and was then transferred to the DFR Standard.

'Yes' Responses	
Peter Burke; ATC; #1	ATC supports the position that an IROL should not be exceeded by more than 30 minutes.
Most industry commenters agreed with this change.	
Lee Xanthakos; SCE&G; #1	I would only add that we should try and focus on consistency. I think Tv is being used in other standards, so I would recommend that these definitions are either coordinated or that different variables are used.
Agreed. The definition of T_v has been modified so that its concept can be used by other SDT's. The revised definition uses the phrase, "IROL T_v", rather than just "T_v".	
Patti Metro; FRCC; #2 Linda Campbell ;FRCC ;#2 Steve Wallace; Seminole Electric Coop ;#4 Amy Long; Lakeland Electric; #1 Richard Gilbert; Lakeland Electric; #3 Ron Donahey; Tampa Electric Company; #3 Beth Young; Tampa Electric Company ;#3 Roger Hunnicutt ; Gainesville Reg Utl; #5 Roger Westphal ;City of Gainesville; #3 Greg Woessner ;Kissimmee Utility Auth;#3 Ben Sharma ;Kissimmee Utility Auth;#3 Garry Baker; JEA ;#1 Ed DeVarona; Florida Power & Light Co. ;#1	This definition provides guidelines to the RA for establishing limits and implementation of mitigation plans. For clarification, If an entity (Reliability Authority, Balancing Authority, Transmission Operator, etc…) is going to report an SOL to the RA and the RA will make the determination as to whether or not the SOL is indeed an IROL, should the clock not start until the determination is made by the RA? What happens if the RA takes 20-30 minutes trying to determine if an IROL exists?

Preston Pierce; Progress Energy Florida ;#1 Bob Remley; Clay Electric Cooperative; #4 Joe Krupar; FMPA; #3 Paul Elwing; Lakeland Electric; #5 Joe Roos; Ocala Electric Utility ;#3	
The RA is expected to have the capability of observing real-time values against IROLs, so the RA should always know whether a limit is an IROL. The definition of an IROL has been modified to make it easier to identify IROLs. The duration of an IROL event is measured from the point in time where the limit is first exceeded for at least 30 continuous seconds and ends at the beginning of the continuous 30 seconds in which the value returns to within the Interconnection Reliability Operating Limit.	
Ralph Rufrano; NYPA; #1 David Kiguel; Hydro One Networks Inc.; #1 Roger Champagne; H-Q TransÉnergie; #1 Greg Campoli; New York ISO (NYISO); #2 Peter Lebro; National Grid; #1 Kathleen Goodman; ISO-NE; #2 Dan Stosick; ISO-NE;#2 Al Adamson; NYSRC;#2 Khagan Khan; The IMO Ontario; #2 Brian Hogue; NPCC;#2 Guy Zito; NPCC;#2 Lawrence Hochberg; NYSRC; #2 James Castle; NYISO ;#2 John Ravalli; NYISO; #2 Karl Tammar; NYISO; #2 Robert Waldele; NYISO; #2 Michael Calimano; NYISO; #2	NPCC participating CP9 members participating (NYSRC) (NYISO) agree that the Tv should be limited to 30 mins. However the last sentence should read Tv shall not be greater than 30 minutes. Add discussion to Q&A document to give rationale as to why Tv under 30 minutes is required.
The definition was changed to replace the word, ‘may’ with ‘shall’ as suggested. The Q&A document already includes a rationale for allowing T_v to be set lower than 30 minutes.	
John Swanson;NPDD;2 Darrick Moe;WAPA;2 Lloyd Linke;WAPA;2 Paul Koskela; MP; 2 Larry Larson; OTP; 2 Dick Pursley; GRE; 2 Martin Trence; XCEL; 2 Todd Gosnell; OPPD; 2 Robert Coish; MH; 2 Joe Knight; MAPPCOR; 2 Tom Mielnik; MEC; 2 Dave Jacobson; MH; 2	The definitions of SOL, IROL, Local Area and Widespread area used in the NERC Operating Limit Definitions and Reporting document approved at the March 23 NERC OC meeting should be used instead of incorporating DOE definitions.

<table>
<tr><td>Delyn Helm; GRE; 2
Jason Weiers; OTP; 2
Dennis Kimm; MEC; 2</td><td></td></tr>
<tr><td colspan="2">Although these terms were accepted by the OC, they did not receive the same level of industry debate that the new standards process requires. In addition, the OLDTF's definitions do not match the definitions included in the Compliance Templates adopted by the NERC BOT.</td></tr>
<tr><td>Alan Gale; City of Tallahassee; #5
Rusty Foster; City of Tallahassee; #3</td><td>When would the clock start? When the SOL is reported, after the RA determination that it is an IROL, or after the RA tells the reporting entity that it is an IROL? I recommend not starting the 30 minute clock until after the RA determines it is an IROL.</td></tr>
<tr><td colspan="2">The RA is expected to have the capability of observing real-time values against IROLs, so the RA should always know whether a limit is an IROL. The definition of an IROL has been modified to make it easier to identify IROLs. The duration of an IROL event starts when a limit has been exceeded for a minimum of 30 seconds, this is to preclude penalties associated with telemetry errors.</td></tr>
<tr><td>Ken Githens; Allegheny Energy 5</td><td>However, the standard needs to define acceptable risks.</td></tr>
<tr><td colspan="2">The requirement to identify which SOLs are also IROLs was moved to the Determine Facility Ratings, System Operating Limits and Transfer Capabilities Standard (DFR Standard). The DFR Standard includes a requirement that the methodology for determining SOLs (and for determining which subset of SOLs are IROLs), be shared with other RAs and also requires the methodology owner to be responsive to any technical comments received on that methodology. This should facilitate RAs working together to determine what constitutes 'acceptable risk'.</td></tr>
<tr><td>Karl Kohlrus; City Water, Light & Power; # 5</td><td></td></tr>
<tr><td>Michael Zahorik; ATC; #1</td><td></td></tr>
<tr><td>Gerald Rheault; Manitoba Hydro; #1,3,5,6</td><td></td></tr>
<tr><td>William Pope; Gulf Power Co; #3</td><td></td></tr>
<tr><td>James Murphy; BPAT;#1
Mike Viles; BPAT; #1
Richard Spence; BPAT; #1
Don Watkins; BPAT; #1
Don Gold; BPAT; #1
Marv Landauer; BPAT; #1</td><td></td></tr>
<tr><td>Dale McMaster; AESO; #2
Ed Riley; CAISO; #2
Sam Jones; ERCOT; #2
Don Tench ; IMO; #2
Dave LaPlante; ISO_NE; #2
William Phillips; MISO; #2
Karl Tammar; NYISO; #2
Bruce Balmat; PJM; #2
Carl Monroe; SPP ; #2</td><td></td></tr>
<tr><td>William Smith; Allegheny Power; #1</td><td></td></tr>
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Mark Fidrych; WAPA; #1	
Anita Lee; AESO; #2	
Chifong Thomas; PG&E; #1 Glenn Rounds; PG&E; #1 Ben Morris; PG&E; #1	
Al Corbet; TVA Jerry Landers; TVA Jennifer Weber; TVA Edd Forsythe; TVA Larry Goins; TVA Mark Creech; TVA Kathy Davis; TVA	
R. Peter Mackin; TRANC; #1	
Carter Edge; SEPA ; #4 & 5 William Gaither; SC Public Svc Auth; #1 Ken Skroback; AL Elec Coop ; #1 Roger Brand; Muni Elec Auth of GA; #1 Phil Creech; Progress Energy - Carolinas; #1 Gene Delk; SCE&G; #1 Al McMeekin; SCE&G; #1 Randy Hunt; Dominion – VA Pwr; #1 Doug Newbauer; GA System Ops; #1 Mike Clements; TVA; #1 Don Reichenbach; Duke Energy; #1 Lynna Estep; SERC; #2 Dan Kay; S Mississippi Elec Pwr Assoc; #1 Matt Ansley; Southern Company; #1 Uma Gangadharan; Entergy; #1	
Marc Butts; Southern Company Svcs; #1 Raymond Vice; Southern Company Svcs; #1 Dan Baisden; Southern Company Svcs; #1 Jim Griffith; Southern Company Svcs; #1 Phil Winston; Georgia Power Company; #3 Jim Viikinsalo; Southern Company Svcs; #1 Mike Miller; Southern Company Svcs; #1 Monroe Landrum; Southern Company Svcs; #1 Gwen Frazier; Southern Company Svcs; #1 Steve Williamson; Southern Company Svcs; #1 Rod Hardiman; Southern Company Svcs; #1 Jonathan Glidewell; Southern Company Svcs; 1 Dan Richards; Southern Company Svcs; #1	

<table>
<tr><td>Mike Hardy; Southern Company Svcs; #1
David Majors; Georgia Power Company; #3</td><td></td></tr>
<tr><td>Kathleen Goodman; ISO-NE; #2</td><td></td></tr>
<tr><td>Roman Carter; SCGEM; #5, 6
Joel Dison; SCGEM; #5, 6
Tony Reed; SCGEM; #5, 6
Lloyd Barnes; SCGEM; #5, 6
Clifford Shepard; SCGEM; #5, 6
Lucius Burris; SCGEM; #5, 6
Roger Green; SCGEM; #5, 6</td><td></td></tr>
<tr><td>Khaqan Khan; IMO; #2</td><td></td></tr>
<tr><td>Jalal Babik; Dominion VA Power; #1
Craig Crider; Dominion VA Power; #1
Jack Kerr; Dominion VA Power; #1
Bill Thompson; Dominion VA Power; #1</td><td></td></tr>
<tr><td>Ed Riley; CA-ISO; #2</td><td></td></tr>
<tr><td>Ed Davis; Entergy Services; #1</td><td></td></tr>
<tr><td>John Horakh; MAAC; #2</td><td></td></tr>
<tr><td>Richard Kafka; Pepco; #3</td><td></td></tr>
<tr><td colspan="2">'No' Responses</td></tr>
<tr><td>Dan Boezio; AEP; #1
Ron Ciesiel; SPP; #2
Bob Cochran; SPS; #1
Mike Gammon; KCP&L; #1
Allen Klassen; Westar; #1
Peter Kuebeck; OG&E; #1
Mike Stafford; GRDA; #1
Robert Rhodes; SPP; #2
Scott Moore; AEP; #1</td><td>If IROLs are truly significant interconnection events, then 30 minutes for Tv is probably a good value. However, if the definition of IROL stays with the proposed limits of 300 MW of load, then 30 minutes may be too short.</td></tr>
<tr><td colspan="2">Agreed. Many commenters indicated that the definition of an IROL needed modification – and it has been changed to focus on the possible impact to the bulk electric system, rather than a quantity of MW. This change supports the concept of 'wide area' as defined in the newly approved compliance templates.</td></tr>
<tr><td>John Blazekovich; Exelon; 1,2,5,6</td><td>Allowing an "acceptable time" of a Interconnection Reliability Operating Limit appears to be inconsistent with the definition of an IROL. If an IROL leads to instability, uncontrolled separation or cascading outage it seems to be unacceptable to allow any time limits to be associated with an IROL violation (i.e. any time spent over an IROL should be a violation).</td></tr>
<tr><td colspan="2">Agreed. The intent of the standard is to prevent ever exceeding an IROL for any length of time. The SDT recognizes that there may be two different types of IROLs – those that result from an incident (such as an airplane that takes out a series of parallel transmission lines) and those that result from evolving conditions (such as the gradual increase in voltage limits resulting from heavy loads). The RA is</td></tr>
</table>

expected to prevent exceeding IROLs that may result from evolving conditions – and the RA is expected to mitigate an incident of exceeding an IROL that results from an incident. This change should make it easier for an RA to identify its IROLs.	
Raj Rana; AEP; 1,3,5,6	How do you consistently define what risk is acceptable and what risk is not? How do we ensure all the RA's evaluate risk using the same criteria and assessment process? The upper limit of 30 minutes is not a problem. However, why would any entity select a Tv less than 30 minutes? Shouldn't the Tv concept require you to take immediate action, if studies show that exceeding this IROL could lead to system instability or collapse? An entity should not be allowed to operate such that the occurrence of the next contingency results in a cascading blackout. Under such a scenario, the entity needs to take immediate action as soon as it is identified that they are in such a situation, not wait 30 minutes or wait until the contingency occurs. The problem with this Standard in its current form is that t has watered down an IROL event by tying it to loss of 300 MW of load. For a large system, that may be the loss of only 2 or 3 facilities or less. And it could include events that do not threaten the Interconnection. We would suggest that a Tv of no greater then 30 minutes is adequate for a SOL violation, but may be totally inadequate for a true IROL.
The requirement to identify which SOLs are also IROLs was moved to the Determine Facility Ratings, System Operating Limits and Transfer Capabilities Standard (DFR Standard). The DFR Standard includes a requirement that the methodology for determining SOLs (and for determining which subset of SOLs are IROLs), be shared with other RAs and also requires the methodology owner to be responsive to any technical comments received on that methodology. This should facilitate RAs working together to determine what constitutes 'acceptable risk'. The DFR Standard includes a list of criteria that all System Operating Limits must meet. This should ensure that all SOLs (and IROLs) are established in a manner that ensures that, as long as the system is operated within the specified limits, the system will not suffer instability, cascading outages, or uncontrolled separation. The criteria for establishing SOLs includes things such as the number and types of contingencies that must be considered, definition of assumptions used in establishing SOLs, etc. The DFR Standard includes a requirement that the methodology for determining SOLs (and for determining which subset of SOLs are IROLs), be shared with other RAs and also requires the methodology owner to be responsive to any technical comments received on that methodology. This should facilitate RAs working together to determine what constitutes 'acceptable risk'. WECC already has many IRL's that are set at 20 minutes. The T_v for these limits is set to ensure that the system operators respond before the impact to reliability is unacceptable. In the WECC region, a technical committee establishes the 'base' set of IORLs for the entire interconnection – and the T_v is based on the risk to the interconnection of exceeding the IRL. Note that there was not support for using the threshold of a loss of 300 MW of load for 15 minutes. The revised standard reflects adoption of the definition of widespread that was included in the templates just approved by the NERC BOT. This standard doesn't suggest that anyone wait 30 minutes to resolve an instance of exceeding an IROL – this standard requires that actions be taken to Prevent instances of exceeding an IROL. The industry has indicated that they do not want any IROL T_v greater than 30 minutes, and that language is reflected in this standard.	

4. Wide Area Impact

Several balloters indicated a continued misunderstanding of the difference between 'wide area impact' and 'local area'. The SDT modified the definition in an attempt to make the definition more objective. The Department of Energy currently requires that any single incident involving the uncontrolled loss of 300 MW or more of firm system loads be reported on form DOE EIA 417. The SDT adopted this criterion as the threshold for determining whether the impact of an event was 'widespread'. (Note that while the term, 'wide area impact' is not used in this standard, it is used in the definition of an IROL.) Do you agree with the revised definition for Wide Area Impact?

Original Definition: Wide Area Impact: The impact of a single incident resulting in the uncontrolled loss of 300 MW or more of networked system load for a minimum of 15 minutes.

Summary Consideration: The SDT endorses the definition of Wide Area that was recently approved by the NERC BOT with the new compliance templates , but recommends deleting the last phrase of the definition and substituting RA for RC. (The last phrase of the definition provides one use of the term 'wide area' – but the use cited is not the only use of the term 'wide area'.)

Revised Definition: Wide-Area: The entire Reliability Authority Area as well as that critical flow and status information from adjacent Reliability Authority Areas as determined by detailed system analysis or studies.

Yes Responses	
William Pope; Gulf Power Co; #3	See No. 2 above.
See response to No. 2.	
Marc Butts; Southern Company Svcs; #1 Raymond Vice; Southern Company Svcs; #1 Dan Baisden; Southern Company Svcs; #1 Jim Griffith; Southern Company Svcs; #1 Phil Winston; Georgia Power Company; #3 Jim Viikinsalo; Southern Company Svcs; #1 Mike Miller; Southern Company Svcs; #1 Monroe Landrum; Southern Company Svcs; #1 Gwen Frazier; Southern Company Svcs; #1 Steve Williamson; Southern Company Svcs; #1 Rod Hardiman; Southern Company Svcs; #1 Jonathan Glidewell; Southern Company Svcs; 1 Dan Richards; Southern Company Svcs; #1 Mike Hardy; Southern Company Svcs; #1 David Majors; Georgia Power Company; #3	Same concern as #2 above.
See response to #2.	
Lee Xanthakos; SCE&G; #1	Having agreed with the definition above, I am inclined to agree here as well.
While several commenters did agree with this definition, many others did not. The SDT adopted a definition very similar to the definition recently approved by the NERC BOT in the new compliance templates.	
James Murphy; BPAT;#1	Remove definition if it is no longer used.

Mike Viles; BPAT; #1 Richard Spence; BPAT; #1 Don Watkins; BPAT; #1 Don Gold; BPAT; #1 Marv Landauer; BPAT; #1	
The SDT adopted the definition very similar to the one recently approved by the NERC BOT in the new compliance template. The term, 'wide area,' is used in the revised standard.	
John Horakh; MAAC; #2	The definition uses the expression "networked system load", which implies that "single source fed system load" is excluded. Therefore, we would conclude that the loss of 300 MW or more of "single source fed system load" does not have "Wide Area Impact". Is that the intent of the definition?
The original intent was to exclude single source fed system loads.	
Karl Kohlrus; City Water, Light & Power; # 5	
John Blazekovich; Exelon; 1,2,5,6	
Patti Metro; FRCC; #2 Linda Campbell ;FRCC ;#2 Steve Wallace; Seminole Electric Coop ;#4 Amy Long; Lakeland Electric; #1 Richard Gilbert; Lakeland Electric; #3 Ron Donahey; Tampa Electric Company; #3 Beth Young; Tampa Electric Company ;#3 Roger Hunnicutt ; Gainesville Reg Utl; #5 Roger Westphal ;City of Gainesville; #3 Greg Woessner ;Kissimmee Utility Auth;#3 Ben Sharma ;Kissimmee Utility Auth;#3 Garry Baker; JEA ;#1 Ed DeVarona; Florida Power & Light Co. ;#1 Preston Pierce; Progress Energy Florida ;#1 Bob Remley; Clay Electric Cooperative; #4 Joe Krupar; FMPA; #3 Paul Elwing; Lakeland Electric; #5 Joe Roos; Ocala Electric Utility ;#3	
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Gerald Rheault; Manitoba Hydro; #1,3,5,6	
Roman Carter; SCGEM; #5, 6 Joel Dison; SCGEM; #5, 6 Tony Reed; SCGEM; #5, 6 Lloyd Barnes; SCGEM; #5, 6 Clifford Shepard; SCGEM; #5, 6	

Lucius Burris; SCGEM; #5, 6 Roger Green; SCGEM; #5, 6	
Alan Gale; City of Tallahassee; #5 Rusty Foster; City of Tallahassee; #3	
Richard Kafka; Pepco; #3	
'No' Responses	
Dale McMaster; AESO; #2 Ed Riley; CAISO; #2 Sam Jones; ERCOT; #2 Don Tench ; IMO; #2 Dave LaPlante; ISO_NE; #2 William Phillips; MISO; #2 Karl Tammar; NYISO; #2 Bruce Balmat; PJM; #2 Carl Monroe; SPP ; #2 Anita Lee; AESO; #2	Wide Area Impact should be defined in relation to a BA or RA footprint. The measure should be that a wide area event occurs when an event has an impact in two or more BA or RA areas.
The SDT adopted the definition approved by the NERC BOT in the recently approved compliance templates, with minor modifications – and the new definition supports your recommendation.	
Peter Burke; ATC; #1	"Note that while the term, 'wide area impact' is not used in this standard, it is used in the definition of an IROL." The term 'Wide area impact' is in the list of definitions but that term does not appear anywhere in the definition of an IROL. If is not used in the standard or in the definition of an IROL then should it not be removed from the definitions list?
Many commenters asked that the term be defined because an understanding of 'widespread' or 'wide area impact' was critical to determining whether an SOL should be considered an IROL. Note that the term, 'wide area' is used in the revised standard.	
Chifong Thomas; PG&E; #1 Glenn Rounds; PG&E; #1 Ben Morris; PG&E; #1	For some systems, it is not uncommon to have loads of 300 MW or more located in a small area. Loss of 300 MW is therefore not an indication of wide area impacts. If implemented, such criteria could significantly increase workload and take resources away from work needed to identify, analyze, monitor and mitigate problems concerning IROLs, the violation of which could truly lead to cascading.
Agreed. Most commenters indicated that the suggested thresholds were too low and would be impractical and they have been dropped from the revised standard.	
William Smith; Allegheny Power; #1	This definition would qualify the loss of a single industrial customer (greater than 300MWs) as a wide area impact. A wide area impact should be defined as the loss of multiple substations or facilities than result in multiple customer outages totaling 300MWs or greater.
Agreed. Most commenters indicated that the suggested thresholds were too low and would be	

impractical and they have been dropped from the revised standard.	
John Swanson;NPDD;2 Darrick Moe;WAPA;2 Lloyd Linke;WAPA;2 Paul Koskela; MP; 2 Larry Larson; OTP; 2 Dick Pursley; GRE; 2 Martin Trence; XCEL; 2 Todd Gosnell; OPPD; 2 Robert Coish; MH; 2 Joe Knight; MAPPCOR; 2 Tom Mielnik; MEC; 2 Dave Jacobson; MH; 2 Delyn Helm; GRE; 2 Jason Weiers; OTP; 2 Dennis Kimm; MEC; 2	The definitions of SOL, IROL, Local Area and Widespread area used in the NERC Operating Limit Definitions and Reporting document approved at the March 23 NERC OC meeting should be used instead of incorporating DOE definitions.
Although these terms were accepted by the OC, they did not receive the same level of industry debate that the new standards process requires. The SDT adopted the definitions included in the Compliance Templates adopted by the NERC BOT, with slight modifications to make them align with the Functional Model.	

<table>
<tr><td>Greg Campoli; NYISO; #2
James Castle; NYISO ;#2
John Ravalli; NYISO; #2
Karl Tammar; NYISO; #2
Robert Waldele; NYISO; #2
Michael Calimano; NYISO; #2
Ralph Rufrano; NYPA; #1
David Kiguel; Hydro One Networks Inc.; #1
Roger Champagne; H-Q TransÉnergie; #1
Greg Campoli; New York ISO (NYISO); #2
Peter Lebro; National Grid; #1
Kathleen Goodman; ISO-NE; #2
Dan Stosick; ISO-NE;#2
Al Adamson; NYSRC;#2
Khagan Khan; The IMO Ontario; #2
Brian Hogue; NPCC;#2
Guy Zito; NPCC;#2
Lawrence Hochberg; NYSRC; #2
Khaqan Khan; IMO; #2</td><td>The NYISO aggress with the definition of Widespread Area from NERC OLDTF Report (that was validated by RCWG at its December/03 meeting and was accepted by NERC OC at its March 2004 meeting) be used in the Standard 200 as well. It is stated as below:

Widespread Area An area that extends beyond any Local Area.
Local Area The portion of a Widespread Area, whose boundaries are predetermined by appropriate analyses, where the impact of a Contingency or other event will not cause instability, uncontrolled separations or cascading outages to propagate beyond those predetermined boundaries (i.e., will not impact the overall reliability of a major portion of the Interconnection.) Impact to a Widespread Area indicates significant impact to the Interconnection.
OR an alternative option/suggestion is also proposed as follows:
"The impact of an incident resulting in uncontrolled successive loss of system elements in networked system and where the consequences of such significant adverse impact cannot be contained within a defined area that can be demonstrated by studies.

Wide area impact may also be defined correlating it to occurrences of event impacting more than one Reliability Authority.</td></tr>
<tr><td colspan="2">Although these terms were accepted by the OC, they did not receive the same level of industry debate that the new standards process requires. The SDT adopted the definition of Wide Area included in the Compliance Templates adopted by the NERC BOT, with slight modifications to align with the Functional Model.</td></tr>
<tr><td>Khaqan Khan; IMO; #2</td><td>An alternative recommended approach/measure is that a wide area impact be defined with respect to occurrence of event impacting more than two RAs or BAs areas.</td></tr>
<tr><td colspan="2">This is the concept supported by the definition of Wide Area adopted by the NERC BOT in the newly approved compliance templates – and has been endorsed by the SDT for this standard.</td></tr>
<tr><td>Michael Zahorik; ATC; #1</td><td>Again 300 Mw is too low. There needs to be some definition of netwrok impact. ATC has areas were 300 Mw can be lost and that lost will not affect the network.</td></tr>
<tr><td colspan="2">Agreed. Most commenters indicated that 300 MW was too low a threshold. The revised standard does not include any MW threshold.</td></tr>
<tr><td>Raj Rana; AEP; 1,3,5,6</td><td>The DOE threshold was never intended to imply that it defined a wide area impact. The definition for wide area impact needs to include the concept that multiple facilities are impacted, and exceeds a large geographic footprint. For a large entity, 300 MW can</td></tr>
</table>

	be as little as 1% of their peak load, arguably not a wide area impact for them. It make sense to set a quantitative threshold. However, such threshold should not be so limiting as for larger systems to be able to be exceeded by a single event. What is missing in this Standards is the concept that we need to prevent events that put the interconnection at risk. Instead this Standards is focusing on events within a single Control Area or Transmission Operator footprint. For convenience, a 300 MW threshold has been suggested, but there is no reference to impact to the interconnection. I guess one can argue, that if we force such severely constrained operations at the local level, then we should never get to the point of placing risks on the Interconnection. Is that the point of this standard? If so, then this is not about operating to IROL's but rather in operating well under SOL's so as to never approach an IROL. The definition continues to miss the mark and remains unclear. If the SDT see a need to define a "Wide Area Impact" using a arbitrary load at risk level, may be acceptable. But under the current definition, is the loss of a 5000 MW load area for 12 minutes a wide area impact? Per definition the answer is no, practicality says 'yes'.
The SDT adopted the definition of Wide Area included in the Compliance Templates adopted by the NERC BOT, with slight modifications to align with the Functional Model. This standard includes several elements aimed at supporting the Prevention of exceeding an IROL.	
Marv Landauer; BPA; #2	I do not agree that this is the appropriate definition of wide area impact. However I also do not see that this term is used anywhere in the document, so I suggest that it be removed entirely.
The SDT adopted the definition of Wide Area included in the Compliance Templates adopted by the NERC BOT, with slight modifications to align with the Functional Model. Many commenters requested that this definition be included because understanding whether exceeding a limit will have 'wide area' impact is critical to determining whether that limit should be an IROL. In addition, the revised standard does use the term, 'wide area'.	
Kathleen Goodman; ISO-NE; #2	The definition should capture the concept of Interconnection impact. Agreed with the concept of "uncontrolled successive loss," but do not agree that the 300 MW is an appropriate measure. The loss of 300 MW of load has nothing to do with cascading or uncontrolled successive losses. You may lose over 300 MW of load, but it poses no risk to the interconnection. We believe that the standard should be that the cascading outages propagate beyond the local area (i.e. Control Area). Specific, hard, concrete examples about how IROLs are calculated, including specific contingency pair examples for things like thermal limits, are needed such that the whole industry can understand what an IROL is.

Agreed. The SDT adopted the definition of Wide Area included in the Compliance Templates adopted by the NERC BOT, with slight modifications to align with the Functional Model. The requirement to have a documented methodology for determining SOLs (and the subset of SOLs that are IROLs) has been moved to the Determine Facility Ratings, System Operating Limits and Transfer Capabilities Standard. The revised Standard 603 includes a set of criteria for establishing SOLs and consequently for establishing IROLs.	
Carter Edge; SEPA ; #4 & 5 William Gaither; SC Public Svc Auth; #1 Ken Skroback; AL Elec Coop ; #1 Roger Brand; Muni Elec Auth of GA; #1 Phil Creech; Progress Energy - Carolinas; #1 Gene Delk; SCE&G; #1 Al McMeekin; SCE&G; #1 Randy Hunt; Dominion – VA Pwr; #1 Doug Newbauer; GA System Ops; #1 Mike Clements; TVA; #1 Don Reichenbach; Duke Energy; #1 Lynna Estep; SERC; #2 Dan Kay; S Mississippi Elec Pwr Assoc; #1 Matt Ansley; Southern Company; #1 Uma Gangadharan; Entergy; #1	See comments above
See responses to prior comments.	
R. Peter Mackin; TRANC; #1	This definition does not contain any energy values. Taking this definition literally would mean if a system lost 10,000 MW and was able to restore it in 14 minutes (admittedly, a highly unlikely occurrence), the outage would not be considered to have a wide area impact. A better definition would include an energy component, for example, 75 MWh. The revised definition would read: The impact of a single incident resulting in the uncontrolled loss of 300 MW or more of networked system load for a minimum of 15 minutes or the loss of 75 MWh or more during a time interval of 15 minutes or less.
The SDT adopted the definition of Wide Area included in the Compliance Templates adopted by the NERC BOT, with slight modifications to align with the Functional Model.	
Jalal Babik; Dominion VA Power; #1 Craig Crider; Dominion VA Power; #1 Jack Kerr; Dominion VA Power; #1 Bill Thompson; Dominion VA Power; #1	See item 2 comments. Also, a dynamic instability can cause power system oscillations and equipment "swinging" over a large part of an interconnection and yet result in no loss of load. This situation could be caused by a single incident such as loss of a long line or a malfunction of a power system stabilizer and would definitely be considered to have a wide area impact on the reliability of the interconnection and the safety of interconnected equipment. The proposed definition is not applicable. The definition of Wide Area Impact is not consistent with the definition of Wide Area that appears in the

<table>
<tr><td></td><td>revised Policy 9 currently being balloted by the Standing Committees.</td></tr>
<tr><td colspan="2">The SDT adopted the definition of Wide Area that was approved by the Standing Committees and adopted by the NERC BOT in the new compliance templates. This is a minor modification to the definition included in Policy 9.</td></tr>
<tr><td>Dan Boezio; AEP; #1
Ron Ciesiel; SPP; #2
Bob Cochran; SPS; #1
Mike Gammon; KCP&L; #1
Allen Klassen; Westar; #1
Peter Kuebeck; OG&E; #1
Mike Stafford; GRDA; #1
Robert Rhodes; SPP; #2
Scott Moore; AEP; #1</td><td>This term does not appear in the standard, why does it need to be defined here?

If it is felt that the definition must be included, then 300 MW is too small to be considered a wide area when compared to the interconnection.
.</td></tr>
<tr><td colspan="2">The definition does appear in the revised standard.
Many commenters indicated that using the 300 MW threshold was not appropriate and this reference has been dropped. The SDT has adopted the definition of Wide Area that was approved by the Standing Committees and adopted by the NERC BOT in the new compliance templates, with minor modifications to conform to the Functional Model.</td></tr>
<tr><td>Ed Riley; CA-ISO; #2</td><td>Wide Area Impact should be defined in relation to a BA footprint. The measure should be that a wide area event occurs when an event has an impact in two or more BA areas.</td></tr>
<tr><td colspan="2">The SDT has adopted the definition of Wide Area that was approved by the Standing Committees and adopted by the NERC BOT in the new compliance templates, with minor modifications to conform to the Functional Model.</td></tr>
<tr><td>Ken Githens; Allegheny Energy 5</td><td>This definition would qualify the loss of a single industrial customer (greater than 300MWs) as a wide area impact. A wide area impact should be defined as the loss of multiple substations or facilities than result in multiple customer outages totaling 300MWs or greater.</td></tr>
<tr><td colspan="2">The SDT has adopted the definition of Wide Area that was approved by the Standing Committees and adopted by the NERC BOT in the new compliance templates, with minor modifications to conform to the Functional Model.</td></tr>
<tr><td>Ed Davis; Entergy Services; #1</td><td>We suggest the definition of Wide Area Impact should include a number of transmission providers, rather than MWs of load, and propose the following:

Wide Area Impact: The impact of a single incident resulting <u>from the uncontrolled loss of networked system elements involving two or more transmission providers triggered by an incident at any location that results </u>in the uncontrolled loss ~~of 300 MW~~ of networked system load for a minimum of 15 minutes.</td></tr>
<tr><td colspan="2">The SDT has adopted the definition of Wide Area that was approved by the Standing Committees and adopted by the NERC BOT in the new compliance templates, with minor modifications to conform to the Functional Model.</td></tr>
</table>

Other Comments	
Al Corbet; TVA Jerry Landers; TVA Jennifer Weber; TVA Edd Forsythe; TVA Larry Goins; TVA Mark Creech; TVA Kathy Davis; TVA	See comments to question 2. Also, if "Wide Area " is implied and not used in this document, why have it at all?
The definition does appear in the revised standard. The SDT has adopted the definition of Wide Area that was approved by the Standing Committees and adopted by the NERC BOT in the new compliance templates, , with minor modifications to conform to the Functional Model.	

5. Other Definitions

Several other definitions had minor changes. Please identify any definitions you feel need to be revised, and if possible suggest a revision.

Summary Consideration: The requirement to identify IROLs was shifted to the DFR Standard, and the definition of IROL is now being refined by the DFR SDT. The definition has been modified as follows and the DFR SDT is collecting comments on this definition:

Interconnection Reliability Operating Limit - a System Operating Limit, which, if violated, could result in instability, uncontrolled separation, or Cascading Outages affecting the bulk electric system.

Several commenters asked that a definition of 'shared facility' be provided, and the SDT revised the language in the standard so this term is not used, but its intent is clarified. A shared facility was intended to be a facility that crosses over one or more RA boundaries – so that multiple RAs have a portion of that facility within their RA Area.

Comments	
Karl Kohlrus; City Water, Light & Power; # 5	The definition of real-time data needs to make reference to how often it is collected (e.g. every 4 seconds) and how quickly it is reported (e.g. every 2 seconds).
As used in this standard, real-time data may be collected manually as well as through automatic collection systems. Requirements for tools are expected to be addressed in the Certification Standards.	
John Swanson;NPDD;2 Darrick Moe;WAPA;2 Lloyd Linke;WAPA;2 Paul Koskela; MP; 2 Larry Larson; OTP; 2 Dick Pursley; GRE; 2 Martin Trence; XCEL; 2 Todd Gosnell; OPPD; 2 Robert Coish; MH; 2 Joe Knight; MAPPCOR; 2 Tom Mielnik; MEC; 2 Dave Jacobson; MH; 2 Delyn Helm; GRE; 2 Jason Weiers; OTP; 2 Dennis Kimm; MEC; 2	What is the maximum update interval for Real-time Data?
As used in this standard, real-time data may be collected manually as well as through automatic collection systems. Requirements for tools are expected to be addressed in the Certification Standards.	
John Blazekovich; Exelon; 1,2,5,6	Interconnection Reliability Operating Limit - "that adversely impact the reliability of the bulk electric system" should be removed from the definition to make it consistent with the definition of a SOL, which it is.

The definition of IROL is now being updated by the Determine Facility Ratings, System Operating Limits and Transfer Capabilities SDT.	
Raj Rana; AEP; 1,3,5,6	The definition of an IROL Event Duration lists a reset time of 30 seconds. In204(b)(1)(iii) the reset period is given as one minute. Whichever is the proper intent of the SDT, 30 seconds or 1 minute is too short of a period for the reset. This should be on the order of 5 minutes or so in order to indicate that stable operating conditions have been attained. The definition of an IROL continues to be unclear. For example: If an SOL (system Operating Limit) is a maximum permissible value so as to not exceed a facility rating or reliability criteria, then if 'everyone' was doing their job there should never be an occurrence of an IROL. There should never be a situation where the outage of the next facility will lead to 'instability, uncontrolled separation, or cascading outages'. Therefore, for the system to be exposed to a IROL, a more restricting System Operating Limit must have already been exceeded, unidentified, or ignored.
The reset time is 30 seconds and has been modified so it is constant in both places. The intent of the reset period was not to ensure that the system was 'stable' – the intent of the reset time was to ensure that any telemetry error was excluded. The definition of an IROL is now being updated by the Determine Facility Ratings, System Operating Limits and Transfer Capabilities SDT	
Gerald Rheault; Manitoba Hydro; #1,3,5,6	1. The definition of "Interconnection Reliability Operating Limit" seems clear. However, addition explanation beyond the definition is required to shed light on the intended meaning and application of the term. NERC should consider the creation of a IROL reference document along the lines of the NERC "Transmission Transfer Capability" reference document. 2. The impression is given that IROLs are simply a subset of SOL's as determined using current methods (e.g. study procedures). For some IROLS this will be true, i.e., where current methods demonstrate a specific transfer capability is limited by stability. However, in situations where thermal limits are lower than stability limits, it is not current practice (in MAPP) to expend additional effort to identify higher stability limits. A straight forward interpretation of the definition would require this additional effort. Is this NERC's intent? 3. If so, NERC is introducing an additional requirement beyond current practice. This raises some important questions. How much extra effort is required and is it justified? Will monitoring IROLs derived in this way be fully

	effective to prevent instability, uncontrolled separation, or cascading outages? For example, simultaneously exceeding several thermal limits (individually SOL's not IROLs) may be approaching a voltage instability condition but this condition might not be recognized using the proposed IROL monitoring method. This is a good example of how an IROL might exist which will not be identified by current methods. The implications of the proposed IROL methodology have not been sufficiently explored and documented to ensure effective understanding and application within the electrical industry.
1. The IROL definition is now being updated by the Determine Facility Ratings, System Operating Limits and Transfer Capabilities SDT and that SDT is developing a Technical Reference to identify how to identify IROLs. 2. Yes, this is the intent. 3. Existing Reliability Coordinators are expected to calculate and operate within IROLs today.	
Dale McMaster; AESO; #2 Ed Riley; CAISO; #2 Sam Jones; ERCOT; #2 Don Tench ; IMO; #2 Dave LaPlante; ISO_NE; #2 William Phillips; MISO; #2 Karl Tammar; NYISO; #2 Bruce Balmat; PJM; #2 Carl Monroe; SPP ; #2 Anita Lee; AESO; #2	A definition of "shared facilities" is requested
The SDT modified the standard so the term, 'shared facilities' is no longer used. A shared facility was intended to be a facility that crosses over one or more RA boundaries – so that multiple RAs have a portion of that facility within their RA Area.	
Peter Burke; ATC; #1	ATC brought up a concern during the last posting about the definition of Real-Time Assessment. It seems the SDT is attempting to solve two situations with this one definition. The first goal is to have the RA perform this assessment once every 30 minutes to determine if the current system, using that RA's pre-defined contingency list, is in an IROL situation. The second goal is to project over the time between this assessment and the next scheduled assessment to determine if the RA's area may be approaching or potentially in an IROL. The term Real-Time Assessment seems to support the first goal but, because of its name, does not seem to support the second goal. What if an RA only did the first goal of assessment and did not perform the second? Suggestions would be to:

	Remove the term 'expected system condition' from the definition. Create a new term and standard addressing the requirement for the RA to look over the interval between Assessments and determine if the RA's system may be approaching or potentially in an IROL.
The definition of a Real-time Assessment is: An examination of existing and expected system conditions, conducted by collecting and reviewing immediately available data. The requirement for conducting a real-time assessment includes the following: The Reliability Authority shall perform Real-time Assessments every 30 minutes to determine if its Reliability Authority Area is exceeding any Interconnection Reliability Operating Limits or is expected to exceed any Interconnection Reliability Operating Limits. The comments received from the industry have indicated support for both the definition and the requirement. Both clearly indicate that the assessment has two purposes – to determine if the RA's RA Area is exceeding any IROLs or is expected to exceed any IROLs. Part of developing an 'expectation' is to make a judgment about 'trends' from having conducted assessments every 30 minutes. For example, an RA is expected to notice if three successive Real-time Assessments indicate that a Facility subject to an IROL is creeping towards its IROL.	
Greg Campoli; NYISO; #2 James Castle; NYISO ;#2 John Ravalli; NYISO; #2 Karl Tammar; NYISO; #2 Robert Waldele; NYISO; #2 Michael Calimano; NYISO; #2 Ralph Rufrano; NYPA; #1 David Kiguel; Hydro One Networks Inc.; #1 Roger Champagne; H-Q TransÉnergie; #1 Greg Campoli; New York ISO (NYISO); #2 Peter Lebro; National Grid; #1 Kathleen Goodman; ISO-NE; #2 Dan Stosick; ISO-NE;#2 Al Adamson; NYSRC;#2 Khagan Khan; The IMO Ontario; #2 Brian Hogue; NPCC;#2 Guy Zito; NPCC;#2 Lawrence Hochberg; NYSRC; #2	The terms/definitions in the Standards should be consistent with the terms/definitions outlined in Functional Model (version 2). As an example, there is an inconsistency in definition of Transmission Operator, i.e. Definition of Transmission Operator should be updated to reflect definition stated in version 2 of the Functional Model – i.e. "operates or directs the operation". Definitions should be in one place not in each standard and definitely should not appear if they are in the Functional Model document. The definition of IROL presently given in the recent modified template P2T1 (System Operating/Interconnected Reliability Operating Limits Violations) may better serve the purpose in Std 200 as well. It is suggested to use the same definition with few modifications, as follows: " A subset of system operating limits, which if exceeded, could expose a Widespread Area of the Bulk Electrical system to instability, uncontrolled separations(s) or cascading outages."
The SDT dropped the terms already defined in the Functional Model from the list of terms defined for this standard. The definition of an IROL is now being updated by the Determine Facility Ratings, System Operating Limits and Transfer Capabilities SDT.	
Jalal Babik; Dominion VA Power; #1 Craig Crider; Dominion VA Power; #1 Jack Kerr; Dominion VA Power; #1	The definition of IROL in this standard, "A system operating limit which, if exceeded, could lead to instability, uncontrolled separation, or cascading outages that adversely impact the reliability of the

Bill Thompson; Dominion VA Power; #1	bulk electric system.", is not consistent with the definition in the revised Policy 9 currently being balloted by the Standing Committees, "The value (such as MW, MVar, Amperes, Frequency or Volts) derived from, or a subset of the SYSTEM OPERATING LIMITS, which if exceeded, could expose a widespread area of the BULK ELECTRIC SYSTEM to instability, uncontrolled separation(s) or cascading outages". The definition in this standard loses the concept of wide area.
The definition of an IROL is now being updated by the Determine Facility Ratings, System Operating Limits and Transfer Capabilities SDT	
Al Corbet; TVA Jerry Landers; TVA Jennifer Weber; TVA Edd Forsythe; TVA Larry Goins; TVA Mark Creech; TVA Kathy Davis; TVA	Operational Planning Analysis which states "An analysis of the expected system conditions for the next day's operation and up to 12 months ahead." Currently, Reliability Coordinators have responsibility for real-time through next day and Control Areas have Operational Planning responsibilities up to 12 months. Page 6 of the "question and answers" address this definition and it says that the standard requires that an operational planning analysis be conducted at least once each day, looking ahead at the day ahead. But it appears to me that the definition implies more than next day. Maybe this is okay since the measure does limit it to next day. Most of the SERC RCs have responsibility for multiple control areas. TVA for example does operational planning for several months for the TVA control area, but our scope as RC for AECI, BREC, EKPC is real-time through next day. Scope for RC is real-time through next day. There appears to be a shift in responsibility for this operational planning timeframe, if RC = RA.
The standard requires the RA to do an operational analysis each day for the day ahead. Other standards may be developed that require the RA to conduct an operational analysis that looks further ahead. The definition was intended to be useful to all standards that may be developed. There may be a need for another standard to address Operational Planning that takes place in an operating horizon that covers the timeframe between next day and 12 months.	
Kathleen Goodman; ISO-NE; #2	Generator Owner definition is not needed in this standard.
Agreed. The SDT removed all the definitions from the Functional Model.	
James Murphy; BPAT;#1 Mike Viles; BPAT; #1 Richard Spence; BPAT; #1 Don Watkins; BPAT; #1 Don Gold; BPAT; #1 Marv Landauer; BPAT; #1	IROL "system operating limit" should be capitalized. IROL Event Duration: The time frame should match the standard, definition says 30 seconds, standard says 1 minute (204b1ii) Please include the SOL definition.
Agreed – the term, "system operating limit' has been capitalized in the revised standard. Agreed – the standard was modified to conform to the definition which states that the time frame is 30	

seconds. The Determine Facility Ratings SDT has developed a definition of SOL that has reached industry consensus. We will include it in the revised posting, but will also include a note to indicate that the definition was developed as part of the DFR Standard, and the OWL SDT will not revise this definition.	
Ed Riley; CA-ISO; #2	A definition of "shared facilities" is requested.
The standard has been revised so the term is no longer used. A shared facility was intended to be a facility that crosses over one or more RA boundaries – so that multiple RAs have a portion of that facility within their RA Area.	
Carter Edge; SEPA ; #4 & 5 William Gaither; SC Public Svc Auth; #1 Ken Skroback; AL Elec Coop ; #1 Roger Brand; Muni Elec Auth of GA; #1 Phil Creech; Progress Energy - Carolinas; #1 Gene Delk; SCE&G; #1 Al McMeekin; SCE&G; #1 Randy Hunt; Dominion – VA Pwr; #1 Doug Newbauer; GA System Ops; #1 Mike Clements; TVA; #1 Don Reichenbach; Duke Energy; #1 Lynna Estep; SERC; #2 Dan Kay; S Mississippi Elec Pwr Assoc; #1 Matt Ansley; Southern Company; #1 Uma Gangadharan; Entergy; #1	Uncontrolled separation – Cascading outages (new proposed definition above) that lead to the unplanned break-up of an interconnection.
The SDT's are trying to limit the number of defined terms to those that could be reasonably interpreted to mean different things to different entities. Uncontrolled separation seems to be self-evident. If other entities suggest that this term be defined, your definition will be suggested.	
Dan Boezio; AEP; #1 Ron Ciesiel; SPP; #2 Bob Cochran; SPS; #1 Mike Gammon; KCP&L; #1 Allen Klassen; Westar; #1 Peter Kuebeck; OG&E; #1 Mike Stafford; GRDA; #1 Robert Rhodes; SPP; #2 Scott Moore; AEP; #1	The definition of an IROL Event Duration lists a reset time of 30 seconds. In 204(b)(1)(ii) the reset period is given as one minute. Whichever the case, 30 seconds or 1 minute is too short of a period for the reset. This should be on the order of 5 minutes or so in order to indicate that stable operating conditions have been attained.
The reset time is 30 seconds and has been modified so it is constant in both places. The intent of the reset period was not to ensure that the system was 'stable' – the intent of the reset time was to ensure that any telemetry error was excluded.	
Lee Xanthakos; SCE&G; #1	I recommend that the drafting team stays away from defining terms that are already defined. For example, I think that Generator Owner, Reliability Authority Area, and Transmission owner are already defined in the functional model. Also, I recommend that the drafting team communicate with other drafting teams an make sure that the definitions used here are consistent throughout the standards – Performance-reset Period for example

Agreed. The definitions from the Functional Model have been dropped. The Director-Standards is trying to ensure that definitions are shared between drafting teams.	
William Pope; Gulf Power Co; #3	All definitions are acceptable.
Roman Carter; SCGEM; #5, 6 Joel Dison; SCGEM; #5, 6 Tony Reed; SCGEM; #5, 6 Lloyd Barnes; SCGEM; #5, 6 Clifford Shepard; SCGEM; #5, 6 Lucius Burris; SCGEM; #5, 6 Roger Green; SCGEM; #5, 6	All are improved and acceptable
Marc Butts; Southern Company Svcs; #1 Raymond Vice; Southern Company Svcs; #1 Dan Baisden; Southern Company Svcs; #1 Jim Griffith; Southern Company Svcs; #1 Phil Winston; Georgia Power Company; #3 Jim Viikinsalo; Southern Company Svcs; #1 Mike Miller; Southern Company Svcs; #1 Monroe Landrum; Southern Company Svcs; #1 Gwen Frazier; Southern Company Svcs; #1 Steve Williamson; Southern Company Svcs; #1 Rod Hardiman; Southern Company Svcs; #1 Jonathan Glidewell; Southern Company Svcs; 1 Dan Richards; Southern Company Svcs; #1 Mike Hardy; Southern Company Svcs; #1 David Majors; Georgia Power Company; #3	all are improved and acceptable

Questions about Requirement 201 — IROL Identification

6. IROLs for shared facilities

Do you agree with the following new measure developed to support the requirement that addresses the handling of 'shared' Facilities?

201(b)(2)(i) The Reliability Authorities that share a Facility (or group of Facilities) shall have an agreed upon process for determining if that Facility (or group of Facilities) is subject to an Interconnection Reliability Operating Limit and for determining the value of that Interconnection Reliability Operating Limit and its associated T_v

Consideration of Comments: While many industry commenters agreed with this change, several commenters indicated this should be addressed in the Coordinate Operations Standard. The Coordinate Operations Standard does include the following requirement that RAs have a process, procedure or plan for activities that require coordination of actions involving more than one RA, and this should include establishing limits for 'shared' facilities:

> (Coordinate Operations Standard 101 - Requirement 1)The Reliability Authority shall have Operating Procedures, Processes, or Plans in place for activities that require notification, exchange of information or coordination of actions with one or more other Reliability Authorities to support interconnection reliability. These Operating Procedures, Processes or Plans shall address Scenarios that affect other Reliability Authority Areas as well as those developed in coordination with other Reliability Authorities.

Several commenters also indicated that language in the newly approved Policies includes a requirement that if two RAs (RCs in current Policy) can't agree on a limit, they should both operate to the most limiting parameter. This change is within the scope of the SAR and has been included in the revised standard.

There were other comments asking for a definition of 'shared facilities'. With the transfer of the requirement to identify and communicate IROLs to the DFR Standard, this Operate within IROLs Standard does not include the term, 'shared' facilities.

'Yes' Responses	
Karl Kohlrus; City Water, Light & Power; # 5	In the event that there are different ratings of the same facility, the lower rating should always be used.
This requirement seems to be adequately addressed by the Coordinate Operations Standard, and has been dropped from this standard. Requirement 201 has been modified to reflect your suggestion.	
Raj Rana; AEP; 1,3,5,6	As per changes being made to NERC Policy 9, the deault is you operate to the most conservative position. Thus if one RC says the facility has an IROL, all RCs need to respect and operate to that IROL.
This requirement seems to be adequately addressed by the Coordinate Operations Standard, and has been dropped from this standard. Requirement 201 has been modified to reflect your suggestion.	
Lee Xanthakos; SCE&G; #1	I agree with this in principle, but real life has shown that agreements on limits and processes are not

	always possible. I recommend that the drafting team adds a clause directing the RAs to use the process that results in the lower value for the limit if agreement can not be reached. They should keep using that limit until agreement is reached.
This requirement seems to be adequately addressed by the Coordinate Operations Standard, and has been dropped from this standard. Requirement 201 has been modified to reflect your suggestion.	
Kathleen Goodman; ISO-NE; #2	We do have a concern about having a formal process. The process could be that both Areas calculate a separate limit for common facilities based upon the internal transmission configuration. However, the Areas agree that they will operate to the more conservative limit.
This requirement seems to be adequately addressed by the Coordinate Operations Standard, and has been dropped from this standard.	
Ralph Rufrano; NYPA; #1 David Kiguel; Hydro One Networks Inc.; #1 Roger Champagne; H-Q TransÉnergie; #1 Greg Campoli; New York ISO (NYISO); #2 Peter Lebro; National Grid; #1 Kathleen Goodman; ISO-NE; #2 Dan Stosick; ISO-NE;#2 Al Adamson; NYSRC;#2 Khagan Khan; The IMO Ontario; #2 Brian Hogue; NPCC;#2 Guy Zito; NPCC;#2 Lawrence Hochberg; NYSRC; #2	Concern exists that the process required may be too formalized and could be a simple email or telephone call that requires affirmation and a formal legal agreement should not be required.
This requirement seems to be adequately addressed by the Coordinate Operations Standard, and has been dropped from this standard.	
Peter Burke; ATC; #1	It's important that the RA's come to some type of commonality when determining if a shared facility should be subject to an IROL. This approach of an agreed upon process should be able to achieve that goal. Would this SDT put out a technical reference on how this type of an agreed upon process should read, with suggested inclusions and reasons for those suggestions?
This requirement seems to be adequately addressed by the Coordinate Operations Standard, and has been dropped from this standard.	

Marc Butts; Southern Company Svcs; #1 Raymond Vice; Southern Company Svcs; #1 Dan Baisden; Southern Company Svcs; #1 Jim Griffith; Southern Company Svcs; #1 Phil Winston; Georgia Power Company; #3 Jim Viikinsalo; Southern Company Svcs; #1 Mike Miller; Southern Company Svcs; #1 Monroe Landrum; Southern Company Svcs; #1 Gwen Frazier; Southern Company Svcs; #1 Steve Williamson; Southern Company Svcs; #1 Rod Hardiman; Southern Company Svcs; #1 Jonathan Glidewell; Southern Company Svcs; 1 Dan Richards; Southern Company Svcs; #1 Mike Hardy; Southern Company Svcs; #1 David Majors; Georgia Power Company; #3 Roman Carter; SCGEM; #5, 6 Joel Dison; SCGEM; #5, 6 Tony Reed; SCGEM; #5, 6 Lloyd Barnes; SCGEM; #5, 6 Clifford Shepard; SCGEM; #5, 6 Lucius Burris; SCGEM; #5, 6 Roger Green; SCGEM; #5, 6	This requirement seems to overlap the requirements in the Coordinate Operations standard. The two standards should be coordinated to avoid unnecessary repetition.
Agreed. It does appear that this requirement will be adequately addressed in the Coordinate Operations Standard's requirement 101 which requires RAs have a process, procedure or plan to address situations where coordination between RAs is required, and this should include establishing limits for 'shared' facilities.	
William Pope; Gulf Power Co; #3	
Gerald Rheault; Manitoba Hydro; #1,3,5,6	
Michael Zahorik; ATC; #1	
John Blazekovich; Exelon; 1,2,5,6	
Patti Metro; FRCC; #2 Linda Campbell ;FRCC ;#2 Steve Wallace; Seminole Electric Coop ;#4 Amy Long; Lakeland Electric; #1 Richard Gilbert; Lakeland Electric; #3 Ron Donahey; Tampa Electric Company; #3 Beth Young; Tampa Electric Company ;#3 Roger Hunnicutt ; Gainesville Reg Utl; #5 Roger Westphal ;City of Gainesville; #3 Greg Woessner ;Kissimmee Utility Auth;#3 Ben Sharma ;Kissimmee Utility Auth;#3 Garry Baker; JEA ;#1	

Ed DeVarona; Florida Power & Light Co. ;#1 Preston Pierce; Progress Energy Florida ;#1 Bob Remley; Clay Electric Cooperative; #4 Joe Krupar; FMPA; #3 Paul Elwing; Lakeland Electric; #5 Joe Roos; Ocala Electric Utility ;#3	
William Smith; Allegheny Power; #1	
Mark Fidrych; WAPA; #1	
Chifong Thomas; PG&E; #1 Glenn Rounds; PG&E; #1 Ben Morris; PG&E; #1	
Al Corbet; TVA Jerry Landers; TVA Jennifer Weber; TVA Edd Forsythe; TVA Larry Goins; TVA Mark Creech; TVA Kathy Davis; TVA	
Carter Edge; SEPA ; #4 & 5 William Gaither; SC Public Svc Auth; #1 Ken Skroback; AL Elec Coop ; #1 Roger Brand; Muni Elec Auth of GA; #1 Phil Creech; Progress Energy - Carolinas; #1 Gene Delk; SCE&G; #1 Al McMeekin; SCE&G; #1 Randy Hunt; Dominion – VA Pwr; #1 Doug Newbauer; GA System Ops; #1 Mike Clements; TVA; #1 Don Reichenbach; Duke Energy; #1 Lynna Estep; SERC; #2 Dan Kay; S Mississippi Elec Pwr Assoc; #1 Matt Ansley; Southern Company; #1 Uma Gangadharan; Entergy; #1	
R. Peter Mackin; TRANC; #1	
Jalal Babik; Dominion VA Power; #1 Craig Crider; Dominion VA Power; #1 Jack Kerr; Dominion VA Power; #1 Bill Thompson; Dominion VA Power; #1	
John Swanson;NPDD;2 Darrick Moe;WAPA;2 Lloyd Linke;WAPA;2	

Paul Koskela; MP; 2 Larry Larson; OTP; 2 Dick Pursley; GRE; 2 Martin Trence; XCEL; 2 Todd Gosnell; OPPD; 2 Robert Coish; MH; 2 Joe Knight; MAPPCOR; 2 Tom Mielnik; MEC; 2 Dave Jacobson; MH; 2 Delyn Helm; GRE; 2 Jason Weiers; OTP; 2 Dennis Kimm; MEC; 2	
Alan Gale; City of Tallahassee; #5 Rusty Foster; City of Tallahassee; #3	
Ed Riley; CA-ISO; #2	
John Horakh; MAAC; #2	
Ed Davis; Entergy Services; #1	
Dan Boezio; AEP; #1 Ron Ciesiel; SPP; #2 Bob Cochran; SPS; #1 Mike Gammon; KCP&L; #1 Allen Klassen; Westar; #1 Peter Kuebeck; OG&E; #1 Mike Stafford; GRDA; #1 Robert Rhodes; SPP; #2 Scott Moore; AEP; #1	
Ken Githens; Allegheny Energy ; #5	
'No' Responses	
Khaqan Khan; IMO; #2	It is recommended that the standards should be supported by appropriate technical documentation that is allowed under the standards process to ensure a complete understanding of the standard and its consistent applications.
The SDT agrees with this concept. Supporting documents may be developed at any time, and are not part of the technical content that is balloted with the standard, nor are they used for determining compliance.	
James Murphy; BPAT;#1 Mike Viles; BPAT; #1 Richard Spence; BPAT; #1 Don Watkins; BPAT; #1 Don Gold; BPAT; #1 Marv Landauer; BPAT; #1	This should be covered in the coordinate operations standard (#100).
Agreed. This requirement seems to be adequately addressed by the Coordinate Operations Standard,	

and has been dropped from this standard.	
Dale McMaster; AESO; #2 Ed Riley; CAISO; #2 Sam Jones; ERCOT; #2 Don Tench ; IMO; #2 Dave LaPlante; ISO_NE; #2 William Phillips; MISO; #2 Karl Tammar; NYISO; #2 Bruce Balmat; PJM; #2 Carl Monroe; SPP ; #2 Anita Lee; AESO; #2 Greg Campoli; NYISO; #2 James Castle; NYISO ;#2 John Ravalli; NYISO; #2 Karl Tammar; NYISO; #2 Robert Waldele; NYISO; #2 Michael Calimano; NYISO; #2	The wording should be clarified to only include those facilities that are subject to IROLs.
This requirement seems to be adequately addressed by the Coordinate Operations Standard, and has been dropped from this standard. Requirement 201 The Coordinate Operations Standard requires RAs to have a process, procedure or plan to address situations that require coordination of actions involving more than one RA.	

7. Identify 'current' value of IROLs as replacement for 'list' of IROLs

Several balloters asked that the SDT to change this requirement to better reflect that IROLs can be dynamic. The SDT modified the requirement so that instead of requiring a 'list' of IROLs, the RA must be able to identify the 'current value' of its IROLs. Do you agree with this change?

Consideration of Comments: While most industry commenters agreed with this change, this requirement has been transferred to the Determine Facility Ratings (DFR) Standard. As shown below, the DFR Standard achieves the same objective by requiring that end-users provide a schedule for delivery of the limits it needs. The developer of those limits is then required to provide the limits according to the schedule.

> (Determine Facility Ratings Standard 604, Requirement 4) The Reliability Authority, Planning Authority and Transmission Planner shall each provide its System Operating Limits (and Interconnection Reliability Operating Limits) to those entities that have a reliability-related need for those limits and provide a written request that includes a schedule for delivery of those limits as follows:

'Yes' Responses	
Gerald Rheault; Manitoba Hydro; #1,3,5,6	It is not clear how section 201 coordinates with Standard 600 (Determining limits) The requirement that IROLs should be current(reflect current system conditions, i.e. topology, loading, generation, etc.) is not mentioned under Requirements, it is only stated in item 3 of the measures. The difference between Measures (2) and (3) is not clear; they seem to be saying the same thing. The written structure of 201 might be improved by having a one-to-one correspondence between Requirements and measures. Measure (1)(i) does not recognize that changes in topography in an adjacent RA area may impact the current IROL values.
This requirement has been transferred to the DFR Standard. In that standard, the same objective is achieved by requiring that end-users provide a schedule for delivery of the limits it needs. The developer of those limits is required to provide the limits according to the schedule.	
James Murphy; BPAT;#1 Mike Viles; BPAT; #1 Richard Spence; BPAT; #1 Don Watkins; BPAT; #1 Don Gold; BPAT; #1 Marv Landauer; BPAT; #1	It should be made clearer that the IROL facilities can be dynamic also. Some read this as only dynamic IROL values. Implementation plan will also need to change to reflect this update.
This requirement has been transferred to the DFR Standard. In that standard, the same objective is achieved by requiring that end-users provide a schedule for delivery of the limits it needs. The developer of those limits is required to provide the limits according to the schedule.	

Peter Burke; ATC; #1	Although the yes box has been check it does not mean that we support all of the revised changes. The question says the SDT modified the requirement "so that instead of requiring a 'list' of IROL's,…" but, in the measures, you require a list so a list is required. Our concern is not mainly of the list but the idea of how often the list needs to be updated. Since an IROL is a subset of SOL's, would it not be more efficient if the RA could identify those SOL's that are IROLs and show that they are monitoring them? Measures #3 How does the SDT think that this measure can be demonstrated? In our opinion this may only be able to be demonstrated in front of the Compliance Monitor personally.
This requirement has been transferred to the DFR Standard. In that standard, the same objective is achieved by requiring that end-users provide a schedule for delivery of the limits it needs. The developer of those limits is required to provide the limits according to the schedule.	
Patti Metro; FRCC; #2 Linda Campbell ;FRCC ;#2 Steve Wallace; Seminole Electric Coop ;#4 Amy Long; Lakeland Electric; #1 Richard Gilbert; Lakeland Electric; #3 Ron Donahey; Tampa Electric Company; #3 Beth Young; Tampa Electric Company ;#3 Roger Hunnicutt ; Gainesville Reg Utl; #5 Roger Westphal ;City of Gainesville; #3 Greg Woessner ;Kissimmee Utility Auth;#3 Ben Sharma ;Kissimmee Utility Auth;#3 Garry Baker; JEA ;#1 Ed DeVarona; Florida Power & Light Co. ;#1 Preston Pierce; Progress Energy Florida ;#1 Bob Remley; Clay Electric Cooperative; #4 Joe Krupar; FMPA; #3 Paul Elwing; Lakeland Electric; #5 Joe Roos; Ocala Electric Utility ;#3	It appears that this change is reflected in Measure (2) and Noncompliance level (4)(i). There should be a similar change made to the requirements section of 201.
This requirement has been transferred to the DFR Standard. In that standard, the same objective is achieved by requiring that end-users provide a schedule for delivery of the limits it needs. The developer of those limits is required to provide the limits according to the schedule.	
Khaqan Khan; IMO; #2	While the standard considers the requirements that IROLS can be dynamic, it also needs to provide guidance to operators to identify IROLs as they occur. Also refer to comments given in question 13.
This requirement has been transferred to the DFR Standard. In that standard, the same objective is achieved by requiring that end-users provide a schedule for delivery of the limits it needs. The	

<table>
<tr><td colspan="2">developer of those limits is required to provide the limits according to the schedule.</td></tr>
<tr><td>Alan Gale; City of Tallahassee; #5
Rusty Foster; City of Tallahassee; #3</td><td>There is no verbiage in the Requirements section to indicate this change, similar to the changes made in Measure (2) and Non-Compliance level 4(i).</td></tr>
<tr><td colspan="2">This requirement has been transferred to the DFR Standard. In that standard, the same objective is achieved by requiring that end-users provide a schedule for delivery of the limits it needs. The developer of those limits is required to provide the limits according to the schedule.</td></tr>
<tr><td>Kathleen Goodman; ISO-NE; #2</td><td>There is reference in this section indicating “which facilities are subject to,” “shall have a list,” “evidence that the list was updated,” etc.

It is ISO-NE’s position that Standard 200 should clearly reflect the fact that IROL's can be dynamic in nature. While it may be possible that every possible configuration can be identified in advance to deal with this dynamic, the reality is that this list would be extremely large and difficult to maintain. To improve on the situation, this section should require that the RA operators have a base set of limits that include N-1 configurations, along with identifying the following:

The boundary conditions for which the published limits are applicable;
The critical contingency that drive the applicable limit; and
An understanding of what the associated limit is designed to protect the system against (i.e. transient stability, voltage decline, etc.)

The System Operators must have the tools, training and information to deal with unforeseen circumstances and make the proper decisions to secure the system in an expeditious and orderly manner following a contingency or other event.</td></tr>
<tr><td colspan="2">The standard doesn’t dictate how many IROLs any RA may have. The industry has agreed that RAs need to identify facilities subject to IROLs, in advance, so that system operators have the situational awareness needed to be responsive to system changes most likely to affect those facilities.

The standard does not place a limit on how many or how few IROLs there may be in a Region – but no matter how many IROLS there are, they all need to be identified and monitored. This standard does require that the IROLs be identified so they can be used by system operators, but the standard does not require that the IROLs be identified on a ‘list’.

This requirement has been transferred to the DFR Standard. In that standard, the same objective is achieved by requiring that end-users provide a schedule for delivery of the limits it needs. The developer of those limits is required to provide the limits according to the schedule. Note that the DFR Standard does indicate that the methodology for developing SOLs (and for identifying the subset of SOLs that are also IROLs) include identification of the three elements you’ve indicated – boundary conditions critical contingency, and purpose.</td></tr>
<tr><td>Greg Campoli; NYISO; #2
James Castle; NYISO ;#2</td><td>While the standard considers the requirements that IROLS can be dynamic, it also needs to provide guidance to operators to identify IROLs as they</td></tr>
</table>

John Ravalli; NYISO; #2 Karl Tammar; NYISO; #2 Robert Waldele; NYISO; #2 Michael Calimano; NYISO; #2	occur. In addition, the System Operators must have the tools, training and information to deal with unforeseen circumstances and make the proper decisions to secure the system in an expeditious and orderly manner following a contingency or other event.
This requirement has been transferred to the Determine Facility Ratings Standard. In that standard, the same objective is achieved by requiring that end-users provide a schedule for delivery of the limits it needs. The developer of those limits is required to provide the limits according to the schedule. As documented in the recent NERC Operating Committee Operating Limit Definition Task Force Survey, there are many different systems employed for identifying IROLs. The Determine Facility Ratings Standard does not require all RAs to follow the same SOL (and IROL) development process – but does require that each SOL development methodology meet a minimum set of criteria; therefore the standard will not provide guidance to operators on identifying IROLs as they occur. This is considered company-specific training. The scopes of the SAR associated with this standard (and the Determine Facility Ratings Standard) do not address tools or training. Having plans in place to address emergencies is expected to be addressed in other standards. This standard is focused on operating within IROLs – and does require that there be plans in place to both prevent and mitigate instances of exceeding IROLs – these plans are intended to provide system operators with the information needed to make appropriate responses to IROL-related scenarios.	
Ralph Rufrano; NYPA; #1 David Kiguel; Hydro One Networks Inc.; #1 Roger Champagne; H-Q TransÉnergie; #1 Greg Campoli; New York ISO (NYISO); #2 Peter Lebro; National Grid; #1 Kathleen Goodman; ISO-NE; #2 Dan Stosick; ISO-NE;#2 Al Adamson; NYSRC;#2 Khagan Khan; The IMO Ontario; #2 Brian Hogue; NPCC;#2 Guy Zito; NPCC;#2 Lawrence Hochberg; NYSRC; #2	While the standard considers the requirements that IROLS can be dynamic, it also needs to provide guidance to operators to identify IROLs as they occur. Also refer to comments given in question 13. In addition, the System Operators must have the tools, training and information to deal with unforeseen circumstances and make the proper decisions to secure the system in an expeditious and orderly manner following a contingency or other event.
This requirement has been transferred to the Determine Facility Ratings Standard. In that standard, the same objective is achieved by requiring that end-users provide a schedule for delivery of the limits it needs. The developer of those limits is required to provide the limits according to the schedule. As documented in the recent NERC Operating Committee Operating Limit Definition Task Force Survey, there are many different systems employed for identifying IROLs. Determine Facility Ratings Standard does not require all RAs to follow the same SOL (and IROL) development process – but does require that each SOL development methodology meet a minimum set of criteria; therefore the standard will not provide guidance to operators on identifying IROLs as they occur. This is considered company-specific training. See response to question 13. The scopes of the SAR associated with this standard (and the Determine Facility Ratings Standard) do not address tools or training. Having plans in place to address emergencies is expected to be addressed in other standards. This standard is focused on operating within IROLs – and does require that there be plans in place to both prevent and mitigate instances of exceeding IROLs – these plans are intended to provide system operators with the information needed to make appropriate responses to	

IROL-related scenarios.	
Carter Edge; SEPA ; #4 & 5 William Gaither; SC Public Svc Auth; #1 Ken Skroback; AL Elec Coop ; #1 Roger Brand; Muni Elec Auth of GA; #1 Phil Creech; Progress Energy - Carolinas; #1 Gene Delk; SCE&G; #1 Al McMeekin; SCE&G; #1 Randy Hunt; Dominion – VA Pwr; #1 Doug Newbauer; GA System Ops; #1 Mike Clements; TVA; #1 Don Reichenbach; Duke Energy; #1 Lynna Estep; SERC; #2 Dan Kay; S Mississippi Elec Pwr Assoc; #1 Matt Ansley; Southern Company; #1 Uma Gangadharan; Entergy; #1	It would be beneficial to stress that updating the list of facilities should be done continuously to reflect real-time conditions.
This requirement has been transferred to the Determine Facility Ratings Standard. In that standard, the same objective is achieved by requiring that end-users provide a schedule for delivery of the limits it needs. The developer of those limits is required to provide the limits according to the schedule. The requirement to specifically identify the facilities subject to IROLs has been dropped from the standard.	
Lee Xanthakos; SCE&G; #1	I agree with this, but that was not the way I understood it when I read the standard. The “current value” to me means what this value is right now. I recommend the word “current” be changes to something like “set”
Current was intended to mean the value that is effective ‘now’ in ‘real-time’. This requirement has been transferred to the Determine Facility Ratings Standard. In that standard, the same objective is achieved by requiring that end-users provide a schedule for delivery of the limits it needs. The developer of those limits is required to provide the limits according to the schedule.	
Karl Kohlrus; City Water, Light & Power; # 5	
William Pope; Gulf Power Co; #3	
Michael Zahorik; ATC; #1	
Raj Rana; AEP; 1,3,5,6	
Dale McMaster; AESO; #2 Ed Riley; CAISO; #2 Sam Jones; ERCOT; #2 Don Tench ; IMO; #2 Dave LaPlante; ISO_NE; #2 William Phillips; MISO; #2 Karl Tammar; NYISO; #2 Bruce Balmat; PJM; #2 Carl Monroe; SPP ; #2	
William Smith; Allegheny Power; #1	
Mark Fidrych; WAPA; #1	

Anita Lee; AESO; #2	
Chifong Thomas; PG&E; #1 Glenn Rounds; PG&E; #1 Ben Morris; PG&E; #1	
Al Corbet; TVA Jerry Landers; TVA Jennifer Weber; TVA Edd Forsythe; TVA Larry Goins; TVA Mark Creech; TVA Kathy Davis; TVA	
Marc Butts; Southern Company Svcs; #1 Raymond Vice; Southern Company Svcs; #1 Dan Baisden; Southern Company Svcs; #1 Jim Griffith; Southern Company Svcs; #1 Phil Winston; Georgia Power Company; #3 Jim Viikinsalo; Southern Company Svcs; #1 Mike Miller; Southern Company Svcs; #1 Monroe Landrum; Southern Company Svcs; #1 Gwen Frazier; Southern Company Svcs; #1 Steve Williamson; Southern Company Svcs; #1 Rod Hardiman; Southern Company Svcs; #1 Jonathan Glidewell; Southern Company Svcs; 1 Dan Richards; Southern Company Svcs; #1 Mike Hardy; Southern Company Svcs; #1 David Majors; Georgia Power Company; #3	
Roman Carter; SCGEM; #5, 6 Joel Dison; SCGEM; #5, 6 Tony Reed; SCGEM; #5, 6 Lloyd Barnes; SCGEM; #5, 6 Clifford Shepard; SCGEM; #5, 6 Lucius Burris; SCGEM; #5, 6 Roger Green; SCGEM; #5, 6	
Jalal Babik; Dominion VA Power; #1 Craig Crider; Dominion VA Power; #1 Jack Kerr; Dominion VA Power; #1 Bill Thompson; Dominion VA Power; #1	
R. Peter Mackin; TRANC; #1	
John Swanson;NPDD;2 Darrick Moe;WAPA;2 Lloyd Linke;WAPA;2	

Paul Koskela; MP; 2 Larry Larson; OTP; 2 Dick Pursley; GRE; 2 Martin Trence; XCEL; 2 Todd Gosnell; OPPD; 2 Robert Coish; MH; 2 Joe Knight; MAPPCOR; 2 Tom Mielnik; MEC; 2 Dave Jacobson; MH; 2 Delyn Helm; GRE; 2 Jason Weiers; OTP; 2 Dennis Kimm; MEC; 2	
Richard Kafka; Pepco; #3	
Ken Githens; Allegheny Energy ; #5	
Dan Boezio; AEP; #1 Ron Ciesiel; SPP; #2 Bob Cochran; SPS; #1 Mike Gammon; KCP&L; #1 Allen Klassen; Westar; #1 Peter Kuebeck; OG&E; #1 Mike Stafford; GRDA; #1 Robert Rhodes; SPP; #2 Scott Moore; AEP; #1	
John Horakh; MAAC; #2	
Ed Riley; CA-ISO; #2	
'No' Responses	
Ed Davis; Entergy Services; #1	There have been several changes to the Requirements and Measures of 201 and we are unsure to which change this question refers. Therefore, we can not agree with the change at this time.
It would have been helpful if you could have provided guidance on whether the requirement and its measures, as changed, is acceptable.	
Other Comments:	
John Blazekovich; Exelon; 1,2,5,6	Although we agree with the need to monitor the condition of the bulk power electric system, and can reasonably expect that IROL type scenarios and conditions can be studies in the "planning mode", we have concerns that this Standard may be impossible to comply with on a "real time basis". It appears that compliance with this standard will require executing literally hundreds, perhaps thousands of scenarios, it is unlikely one can identify IROLs ahead of time. Especially since each day presents a different system, both from generation pattern perspective and

	from transmission topology perspective.

The definition of IROL was changed to conform to the definition provided in the recently approved Compliance Templates, updated to use the same language as the Functional Model.

This requirement has been transferred to the Determine Facility Ratings Standard. In that standard, the same objective is achieved by requiring that end-users provide a schedule for delivery of the limits it needs. The developer of those limits is required to provide the limits according to the schedule.

If the RA can't update IROLs to reflect real-time conditions, then the RA needs to have conservative operating limits that already include certain system outages or reconfigurations. Note that the Determine Facility Ratings standard includes a set of criteria that must be addressed in establishing SOLs and in identifying the subset of SOLs that are also IROLs. This should help minimize the number of scenarios that must be addressed in establishing operating limits.

8. Do you agree with the compliance monitoring process?

Summary Consideration: While most industry commenters agreed with the revised compliance monitoring process, the associated requirement has been absorbed into the Determine Facility Ratings Standard, and this question is no longer relevant. The SDT did not attempt to answer the responses to this question.

Yes Responses	
Alan Gale; City of Tallahassee; #5 Rusty Foster; City of Tallahassee; #3	There should be some consistency across all the standards for time frames of “requested data”. Without it, the Compliance Monitor can not receive the necessary data for a month and the reporting entity can still be compliant.
Gerald Rheault; Manitoba Hydro; #1,3,5,6	The requirements in item 3 of this section should be expanded to include evidence of agreed procedures to identify IROLs for facilities shared by RAs and to ensure that IROLs reflect current system conditions.
Greg Campoli; NYISO; #2 James Castle; NYISO ;#2 John Ravalli; NYISO; #2 Karl Tammar; NYISO; #2 Robert Waldele; NYISO; #2 Michael Calimano; NYISO; #2	The requirements need to be clear as to what exactly is needed. For example, what constitutes evidence that a list was updated from an auditing perspective?
Karl Kohlrus; City Water, Light & Power; # 5	
John Blazekovich; Exelon; 1,2,5,6	
William Pope; Gulf Power Co; #3	
James Murphy; BPAT;#1 Mike Viles; BPAT; #1 Richard Spence; BPAT; #1 Don Watkins; BPAT; #1 Don Gold; BPAT; #1 Marv Landauer; BPAT; #1	
Michael Zahorik; ATC; #1	
Dale McMaster; AESO; #2 Ed Riley; CAISO; #2 Sam Jones; ERCOT; #2 Don Tench ; IMO; #2 Dave LaPlante; ISO_NE; #2 William Phillips; MISO; #2 Karl Tammar; NYISO; #2 Bruce Balmat; PJM; #2 Carl Monroe; SPP ; #2	

William Smith; Allegheny Power; #1	
Peter Burke; ATC; #1	
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R. Peter Mackin; TRANC; #1	
Marc Butts; Southern Company Svcs; #1 Raymond Vice; Southern Company Svcs; #1 Dan Baisden; Southern Company Svcs; #1 Jim Griffith; Southern Company Svcs; #1 Phil Winston; Georgia Power Company; #3 Jim Viikinsalo; Southern Company Svcs; #1 Mike Miller; Southern Company Svcs; #1 Monroe Landrum; Southern Company Svcs; #1 Gwen Frazier; Southern Company Svcs; #1 Steve Williamson; Southern Company Svcs; #1 Rod Hardiman; Southern Company Svcs; #1 Jonathan Glidewell; Southern Company Svcs; 1 Dan Richards; Southern Company Svcs; #1 Mike Hardy; Southern Company Svcs; #1	

David Majors; Georgia Power Company; #3	
Khaqan Khan; IMO; #2	
Roman Carter; SCGEM; #5, 6 Joel Dison; SCGEM; #5, 6 Tony Reed; SCGEM; #5, 6 Lloyd Barnes; SCGEM; #5, 6 Clifford Shepard; SCGEM; #5, 6 Lucius Burris; SCGEM; #5, 6 Roger Green; SCGEM; #5, 6	
Jalal Babik; Dominion VA Power; #1 Craig Crider; Dominion VA Power; #1 Jack Kerr; Dominion VA Power; #1 Bill Thompson; Dominion VA Power; #1	
John Swanson;NPDD;2 Darrick Moe;WAPA;2 Lloyd Linke;WAPA;2 Paul Koskela; MP; 2 Larry Larson; OTP; 2 Dick Pursley; GRE; 2 Martin Trence; XCEL; 2 Todd Gosnell; OPPD; 2 Robert Coish; MH; 2 Joe Knight; MAPPCOR; 2 Tom Mielnik; MEC; 2 Dave Jacobson; MH; 2 Delyn Helm; GRE; 2 Jason Weiers; OTP; 2 Dennis Kimm; MEC; 2	
John Horakh; MAAC; #2	
Richard Kafka; Pepco; #3	
Ken Githens; Allegheny Energy ; #5	
Ed Davis; Entergy Services; #1	
Ed Riley; CA-ISO; #2	
'No' Responses	

Dan Boezio; AEP; #1 Ron Ciesiel; SPP; #2 Bob Cochran; SPS; #1 Mike Gammon; KCP&L; #1 Allen Klassen; Westar; #1 Peter Kuebeck; OG&E; #1 Mike Stafford; GRDA; #1 Robert Rhodes; SPP; #2 Scott Moore; AEP; #1	We would suggest that the phrase in 201(d)(1) referring to on-site reviews every three years be replaced with on-site reviews as needed.
Raj Rana; AEP; 1,3,5,6	The phrase in 201(d)(1) referring to on-site reviews every three years be replaced with on-site reviews as needed. No reason for the standard to lock into either a 3-year cycle or should leave room for the industry to change the frequency, by a shorter cycle.
Patti Metro; FRCC; #2 Linda Campbell ;FRCC ;#2 Steve Wallace; Seminole Electric Coop ;#4 Amy Long; Lakeland Electric; #1 Richard Gilbert; Lakeland Electric; #3 Ron Donahey; Tampa Electric Company; #3 Beth Young; Tampa Electric Company ;#3 Roger Hunnicutt ; Gainesville Reg Utl; #5 Roger Westphal ;City of Gainesville; #3 Greg Woessner ;Kissimmee Utility Auth;#3 Ben Sharma ;Kissimmee Utility Auth;#3 Garry Baker; JEA ;#1 Ed DeVarona; Florida Power & Light Co. ;#1 Preston Pierce; Progress Energy Florida ;#1 Bob Remley; Clay Electric Cooperative; #4 Joe Krupar; FMPA; #3 Paul Elwing; Lakeland Electric; #5 Joe Roos; Ocala Electric Utility ;#3	(3) indicates that the Reliability Authority must provide certain information upon request of the Compliance Monitor, but does not indicate how long the Reliability Authority has to provide the information. A possible revision could be that " upon request the Reliability Authority will provide the following information to the Compliance Monitor within 5 business days".
Peter Burke; ATC; #1	(2) Is difficult to understand, confusing. Would the SDT please provide greater clarification? (3) i. It is our opinion that this should be a level 4 not level 3. This is a situation were an RA has blatantly ignored this standard and put the Interconnection at risk. (3) ii. Suggestion would be to remove "updated" and replace it with "being reviewed." (4) ii. This should be changed to something where there is no evidence that the RA is actively reviewing its SOL to determine whether it should be classified as an IROL. It seems possible that an RA at a given

	audit time my not have any IROL and, because of that, no list exists which shows any IROL, thus mandating a Level 4 Noncompliance. In Question 7 you stated that a list was not required in requirements.
Kathleen Goodman; ISO-NE; #2	What constitutes "evidence that the list was updated"? For compliance monitoring, all requirements need to be clear as to what exactly is needed.
Ralph Rufrano; NYPA; #1 David Kiguel; Hydro One Networks Inc.; #1 Roger Champagne; H-Q TransÉnergie; #1 Greg Campoli; New York ISO (NYISO); #2 Peter Lebro; National Grid; #1 Kathleen Goodman; ISO-NE; #2 Dan Stosick; ISO-NE;#2 Al Adamson; NYSRC;#2 Khagan Khan; The IMO Ontario; #2 Brian Hogue; NPCC;#2 Guy Zito; NPCC;#2 Lawrence Hochberg; NYSRC; #2	NPCC participating members of CP9 (NYSRC) doesn't agree with having a list of facilities Also, what constitutes evidence that a list was updated from an auditing perspective? The requirements need to be clear as to what exactly is needed.

9. **Do you agree with the levels of non-compliance?**

Summary Consideration: While most industry commenter agreed with the revised levels of non-compliance, the associated requirement has been absorbed into the Determine Facility Ratings Standard and this question is no longer relevant. The SDT did not attempt to answer the responses to this question.

'Yes' Responses	
Patti Metro; FRCC; #2 Linda Campbell ;FRCC ;#2 Steve Wallace; Seminole Electric Coop ;#4 Amy Long; Lakeland Electric; #1 Richard Gilbert; Lakeland Electric; #3 Ron Donahey; Tampa Electric Company; #3 Beth Young; Tampa Electric Company ;#3 Roger Hunnicutt ; Gainesville Reg Utl; #5 Roger Westphal ;City of Gainesville; #3 Greg Woessner ;Kissimmee Utility Auth;#3 Ben Sharma ;Kissimmee Utility Auth;#3 Garry Baker; JEA ;#1 Ed DeVarona; Florida Power & Light Co. ;#1 Preston Pierce; Progress Energy Florida ;#1 Bob Remley; Clay Electric Cooperative; #4 Joe Krupar; FMPA; #3 Paul Elwing; Lakeland Electric; #5 Joe Roos; Ocala Electric Utility ;#3	Level 3 non-compliance indicates that the list must be updated as with the measurements some type of time period should be included.
Alan Gale; City of Tallahassee; #5 Rusty Foster; City of Tallahassee; #3	There should be some consistency across all the standards for time frames of "reviewing or updating". Without it, an entity can only review its documents and programs "at will" and still be compliant.
Ed Riley; CA-ISO; #2	The CAISO supports financial penalties for non-compliance and recognizes that these penalties should be greater than any potential economic advantage to violating a standard.
John Blazekovich; Exelon; 1,2,5,6	
William Pope; Gulf Power Co; #3	
Raj Rana; AEP; 1,3,5,6	
Gerald Rheault; Manitoba Hydro; #1,3,5,6	
James Murphy; BPAT;#1 Mike Viles; BPAT; #1 Richard Spence; BPAT; #1 Don Watkins; BPAT; #1 Don Gold; BPAT; #1	

Marv Landauer; BPAT; #1	
Michael Zahorik; ATC; #1	
Dan Boezio; AEP; #1 Ron Ciesiel; SPP; #2 Bob Cochran; SPS; #1 Mike Gammon; KCP&L; #1 Allen Klassen; Westar; #1 Peter Kuebeck; OG&E; #1 Mike Stafford; GRDA; #1 Robert Rhodes; SPP; #2 Scott Moore; AEP; #1	
Anita Lee; AESO; #2	
Greg Campoli; NYISO; #2 James Castle; NYISO ;#2 John Ravalli; NYISO; #2 Karl Tammar; NYISO; #2 Robert Waldele; NYISO; #2 Michael Calimano; NYISO; #2	
William Smith; Allegheny Power; #1	
Carter Edge; SEPA ; #4 & 5 William Gaither; SC Public Svc Auth; #1 Ken Skroback; AL Elec Coop ; #1 Roger Brand; Muni Elec Auth of GA; #1 Phil Creech; Progress Energy - Carolinas; #1 Gene Delk; SCE&G; #1 Al McMeekin; SCE&G; #1 Randy Hunt; Dominion – VA Pwr; #1 Doug Newbauer; GA System Ops; #1 Mike Clements; TVA; #1 Don Reichenbach; Duke Energy; #1 Lynna Estep; SERC; #2 Dan Kay; S Mississippi Elec Pwr Assoc; #1 Matt Ansley; Southern Company; #1 Uma Gangadharan; Entergy; #1	
Marc Butts; Southern Company Svcs; #1 Raymond Vice; Southern Company Svcs; #1 Dan Baisden; Southern Company Svcs; #1 Jim Griffith; Southern Company Svcs; #1 Phil Winston; Georgia Power Company; #3 Jim Viikinsalo; Southern Company Svcs; #1 Mike Miller; Southern Company Svcs; #1	

Monroe Landrum; Southern Company Svcs; #1 Gwen Frazier; Southern Company Svcs; #1 Steve Williamson; Southern Company Svcs; #1 Rod Hardiman; Southern Company Svcs; #1 Jonathan Glidewell; Southern Company Svcs; 1 Dan Richards; Southern Company Svcs; #1 Mike Hardy; Southern Company Svcs; #1 David Majors; Georgia Power Company; #3	
R. Peter Mackin; TRANC; #1	
Khaqan Khan; IMO; #2	
Roman Carter; SCGEM; #5, 6 Joel Dison; SCGEM; #5, 6 Tony Reed; SCGEM; #5, 6 Lloyd Barnes; SCGEM; #5, 6 Clifford Shepard; SCGEM; #5, 6 Lucius Burris; SCGEM; #5, 6 Roger Green; SCGEM; #5, 6	
John Horakh; MAAC; #2	
Ed Davis; Entergy Services; #1	
Ken Githens; Allegheny Energy ; #5	
Richard Kafka; Pepco; #3	
'No' Responses	
Karl Kohlrus; City Water, Light & Power; # 5	Some of the more serious violations seemed to have the lesser penalties and vice versa
Mark Fidrych; WAPA; #1	The analyses and assess. require once/dy. In some circumstances, where system conditions do not change and the IROL has ample operating room, the requirements do not acknowledge that mode explicitly.
Jalal Babik; Dominion VA Power; #1 Craig Crider; Dominion VA Power; #1 Jack Kerr; Dominion VA Power; #1 Bill Thompson; Dominion VA Power; #1	I agree with the levels for actual operating events, but don't agree with the concept that a newfound definition of an IROL would result in a level 4 under "IROL Identification." In fact, for first time offenses under the heading of "IROL Identification," there should be no monetary fines. My concern is based on disagreement with the definition proposed here. I also disagree with the levels and associated fines under "Analyses and Assessments" since it implies that for one miss of a successful state estimator/contingency analysis run there could be a fine. I want NERC to issue minimum standards for the real-time analysis function that should specify a mean time between failures or to define a maximum allowable downtime for the operation. This is discussed in the US/Canada Task Force Recommendations under number 22. Requiring a

	maximum 30-minute failure, as this standard appears to do, is getting ahead of ourselves in establishing requirements.
John Swanson;NPDD;2 Darrick Moe;WAPA;2 Lloyd Linke;WAPA;2 Paul Koskela; MP; 2 Larry Larson; OTP; 2 Dick Pursley; GRE; 2 Martin Trence; XCEL; 2 Todd Gosnell; OPPD; 2 Robert Coish; MH; 2 Joe Knight; MAPPCOR; 2 Tom Mielnik; MEC; 2 Dave Jacobson; MH; 2 Delyn Helm; GRE; 2 Jason Weiers; OTP; 2 Dennis Kimm; MEC; 2	There are inconsistencies, for instance IROL Identification –no list of facilities subject to IROLs is level 4; Monitoring- List of facilities subject to IROLs not available for Real-time use is level 2.
Kathleen Goodman; ISO-NE; #2	What constitutes "evidence that the list was updated"? For compliance monitoring, all requirements need to be clear as to what exactly is needed.
Ralph Rufrano; NYPA; #1 David Kiguel; Hydro One Networks Inc.; #1 Roger Champagne; H-Q TransÉnergie; #1 Greg Campoli; New York ISO (NYISO); #2 Peter Lebro; National Grid; #1 Kathleen Goodman; ISO-NE; #2 Dan Stosick; ISO-NE;#2 Al Adamson; NYSRC;#2 Khagan Khan; The IMO Ontario; #2 Brian Hogue; NPCC;#2 Guy Zito; NPCC;#2 Lawrence Hochberg; NYSRC; #2	What constitutes evidence that a list was updated from an auditing perspective?
Other Responses	
Dale McMaster; AESO; #2 Ed Riley; CAISO; #2 Sam Jones; ERCOT; #2 Don Tench ; IMO; #2 Dave LaPlante; ISO_NE; #2 William Phillips; MISO; #2 Karl Tammar; NYISO; #2	There was no group consensus – financial penalties are an issue for some groups.

Bruce Balmat; PJM; #2 Carl Monroe; SPP ; #2	
Removing financial penalties are outside the scope of the SDT.	

10. Agreement on Facilities subject to IROLs

Several balloters indicated a concern over coordination of IROLs between RAs. Do you think the standard should include a requirement that the RA obtain agreement from its adjacent RAs on which Facilities in the combined RA Areas are subject to IROLs?

Summary Consideration: While most industry commenters agreed that this is necessary, some commenters indicated this should be addressed by the Coordinate Operations Standard.

The Coordinate Operations Standard does require RAs to have a process, procedure or plan for activities that require coordination of actions involving more than one RA and this should include agreeing on which Facilities in the combined RA Areas are subject to IROLs.

> (Coordinate Operations Standard 101, Requirement 1) The Reliability Authority shall have Operating Procedures, Processes, or Plans in place for activities that require notification, exchange of information or coordination of actions with one or more other Reliability Authorities to support interconnection reliability. These Operating Procedures, Processes or Plans shall address Scenarios that affect other Reliability Authority Areas as well as those developed in coordination with other Reliability Authorities.

Several commenters also suggested that this standard should include the language in Policy 9 which states that if two RAs (RCs in current Policy) can't agree on a limit, they should both operate to the most limiting parameter. This change is within the scope of the SAR and has been included in the revised standard.

Yes Responses	
Ed Riley; CA-ISO; #2	We feel that using a common number for a limit at a boundary or "joint facility" is basic to the reliability of the system. Having a path operated to two different numbers leads to one side potentially scheduling more than the other side can accommodate and can result in "real-time" disagreements and curtailments that should have been handled in the day-ahead scheduling process.
The requirement to coordinate the setting of limits at a boundary is covered in the first requirement of the Coordinate Operations Standard, and was removed from this standard.	
Ralph Rufrano; NYPA; #1 David Kiguel; Hydro One Networks Inc.; #1 Roger Champagne; H-Q TransÉnergie; #1 Greg Campoli; New York ISO (NYISO); #2 Peter Lebro; National Grid; #1 Kathleen Goodman; ISO-NE; #2 Dan Stosick; ISO-NE;#2 Al Adamson; NYSRC;#2 Khagan Khan; The IMO Ontario; #2 Brian Hogue; NPCC;#2 Guy Zito; NPCC;#2	There should be a mutual agreement on the process of coordination among RAs. The process could be that both Areas calculate a separate limit for common facilities based upon the internal transmission configuration. However, the Areas agree that they will operate to the more conservative limit of the different calculation results. Furthermore, it is expected that a need for appropriate analysis/studies shall be outlined that could identify such common impacted facilities. Such requirements can be included in standard 600.

Greg Campoli; NYISO; #2 James Castle; NYISO ;#2 John Ravalli; NYISO; #2 Karl Tammar; NYISO; #2 Robert Waldele; NYISO; #2 Michael Calimano; NYISO; #2	
The Determine Facility Ratings Standard does require the RA to share its SOL development methodology and the process used to identify the subset of IROLs with other RAs, and does require that RAs be responsive to comments received on the methodology used to develop IROLs. Coordination between RAs is addressed in the Coordinate Operations Standard. Several commenters indicated that this requirement is already covered in the Coordinate Operations Standard's first requirement, which requires RAs to have a process, procedure or plan to address situations involving more than one RA. Under the Coordinate Operations Standard, the procedure, process or plan does not need to be a formal agreement.	
Kathleen Goodman; ISO-NE; #2	We do have a concern about having a formal process. The process could be that both Areas calculate a separate limit for common facilities based upon the internal transmission configuration. However, the Areas agree that they will operate to the more conservative limit.
Several commenters indicated that this requirement is already covered in the Coordinate Operations Standard's first requirement, which requires RAs to have a process, procedure or plan to address situations involving more than one RA. Under the Coordinate Operations Standard, the procedure, process or plan does not need to be a formal agreement and could work as you've described. Language has been added to the standard to indicate that if there is a difference of opinion on which value of an IROL to use in real-time operations, the RAs must have agreed in advance to operate to the more conservative limit.	
Khaqan Khan; IMO; #2	We agree that there should be a mutual agreement on coordination among RAs. Furthermore, it is expected that a need for appropriate analysis/studies shall be outlined that could identify such common impactive facilities. Such requirements can be included in standard 600.
The Determine Facility Ratings Standard (Standard 600) does require the RA to share its SOL development methodology and the process used to identify the subset of IROLs with other RAs, and does require that RAs be responsive to comments received on the methodology used to develop IROLs. Standard 600 does require that the methodology used to develop SOLs and the process used to identify the subset of SOLs that are also IROLs meet a set of criteria.	
Lee Xanthakos; SCE&G; #1	I recommend that the drafting team adds a clause directing the RAs to use the process that results in the lower value for the limit if agreement can not be reached. They should keep using that limit until agreement is reached. They should push for agreement.
Language has been added to the standard to indicate that if there is a difference of opinion on which value of an IROL to use in real-time operations, the RAs must have agreed in advance to operate to the more conservative limit.	
Karl Kohlrus; City Water, Light & Power; # 5	
Mark Fidrych; WAPA; #1	

Anita Lee; AESO; #2	
Chifong Thomas; PG&E; #1 Glenn Rounds; PG&E; #1 Ben Morris; PG&E; #1	
William Smith; Allegheny Power; #1	
John Blazekovich; Exelon; 1,2,5,6	
Dale McMaster; AESO; #2 Ed Riley; CAISO; #2 Sam Jones; ERCOT; #2 Don Tench ; IMO; #2 Dave LaPlante; ISO_NE; #2 William Phillips; MISO; #2 Karl Tammar; NYISO; #2 Bruce Balmat; PJM; #2 Carl Monroe; SPP ; #2	
Patti Metro; FRCC; #2 Linda Campbell ;FRCC ;#2 Steve Wallace; Seminole Electric Coop ;#4 Amy Long; Lakeland Electric; #1 Richard Gilbert; Lakeland Electric; #3 Ron Donahey; Tampa Electric Company; #3 Beth Young; Tampa Electric Company ;#3 Roger Hunnicutt ; Gainesville Reg Utl; #5 Roger Westphal ;City of Gainesville; #3 Greg Woessner ;Kissimmee Utility Auth;#3 Ben Sharma ;Kissimmee Utility Auth;#3 Garry Baker; JEA ;#1 Ed DeVarona; Florida Power & Light Co. ;#1 Preston Pierce; Progress Energy Florida ;#1 Bob Remley; Clay Electric Cooperative; #4 Joe Krupar; FMPA; #3 Paul Elwing; Lakeland Electric; #5 Joe Roos; Ocala Electric Utility ;#3	
Carter Edge; SEPA ; #4 & 5 William Gaither; SC Public Svc Auth; #1 Ken Skroback; AL Elec Coop ; #1 Roger Brand; Muni Elec Auth of GA; #1 Phil Creech; Progress Energy - Carolinas; #1 Gene Delk; SCE&G; #1 Al McMeekin; SCE&G; #1 Randy Hunt; Dominion – VA Pwr; #1	

Doug Newbauer; GA System Ops; #1 Mike Clements; TVA; #1 Don Reichenbach; Duke Energy; #1 Lynna Estep; SERC; #2 Dan Kay; S Mississippi Elec Pwr Assoc; #1 Matt Ansley; Southern Company; #1 Uma Gangadharan; Entergy; #1	
R. Peter Mackin; TRANC; #1	
Jalal Babik; Dominion VA Power; #1 Craig Crider; Dominion VA Power; #1 Jack Kerr; Dominion VA Power; #1 Bill Thompson; Dominion VA Power; #1	
Alan Gale; City of Tallahassee; #5 Rusty Foster; City of Tallahassee; #3	
John Swanson;NPDD;2 Darrick Moe;WAPA;2 Lloyd Linke;WAPA;2 Paul Koskela; MP; 2 Larry Larson; OTP; 2 Dick Pursley; GRE; 2 Martin Trence; XCEL; 2 Todd Gosnell; OPPD; 2 Robert Coish; MH; 2 Joe Knight; MAPPCOR; 2 Tom Mielnik; MEC; 2 Dave Jacobson; MH; 2 Delyn Helm; GRE; 2 Jason Weiers; OTP; 2 Dennis Kimm; MEC; 2	
Ed Davis; Entergy Services; #1	
John Horakh; MAAC; #2	
Richard Kafka; Pepco; #3	
Ken Githens; Allegheny Energy ; #5	
'No' Responses	
Dan Boezio; AEP; #1 Ron Ciesiel; SPP; #2 Bob Cochran; SPS; #1 Mike Gammon; KCP&L; #1 Allen Klassen; Westar; #1 Peter Kuebeck; OG&E; #1 Mike Stafford; GRDA; #1	This should be incorporated in the Coordinate Operations standard and doesn't need to be repeated here.

Robert Rhodes; SPP; #2 Scott Moore; AEP; #1	
Agreed. Several commenters made the same suggestion, and this requirement was removed from this standard.	
James Murphy; BPAT;#1 Mike Viles; BPAT; #1 Richard Spence; BPAT; #1 Don Watkins; BPAT; #1 Don Gold; BPAT; #1 Marv Landauer; BPAT; #1	This should be covered in the coordinate operations standard (#100).
Agreed. Several commenters made the same suggestion, and this requirement was removed from this standard.	
Gerald Rheault; Manitoba Hydro; #1,3,5,6	There should be a requirement that the RA obtain agreement from its adjacent RAs on which facilities in the combined RA Areas are subject to IROLs, however the Standard to address this requirement should be Standard 100 “Coordinate Operations” and not this Standard.
Agreed. Several commenters made the same suggestion, and this requirement was removed from this standard.	
Peter Burke; ATC; #1	We are not convinced that a formal agreement has to be in place for adjacent RAs to determine if a facility should be subject to an IROL but there should be a mutually agreed upon process / procedure to identify and honor those facilities identified.
Agreed. Several commenters indicated that this requirement is already covered in the Coordinate Operations Standard’s first requirement, which requires RAs to have a process, procedure or plan to address situations involving more than one RA. Under the Coordinate Operations Standard, the procedure, process or plan does not need to be a formal agreement.	
Marc Butts; Southern Company Svcs; #1 Raymond Vice; Southern Company Svcs; #1 Dan Baisden; Southern Company Svcs; #1 Jim Griffith; Southern Company Svcs; #1 Phil Winston; Georgia Power Company; #3 Jim Viikinsalo; Southern Company Svcs; #1 Mike Miller; Southern Company Svcs; #1 Monroe Landrum; Southern Company Svcs; #1 Gwen Frazier; Southern Company Svcs; #1 Steve Williamson; Southern Company Svcs; #1 Rod Hardiman; Southern Company Svcs; #1 Jonathan Glidewell; Southern Company Svcs; 1 Dan Richards; Southern Company Svcs; #1 Mike Hardy; Southern Company Svcs; #1 David Majors; Georgia Power Company; #3 Roman Carter; SCGEM; #5, 6	The Standard already states that RAs that share a facility, having an IROL, will agree to a ‘process’ for determining if it qualifies and what the value should be. Being more prescriptive doesn’t add anything here.

Joel Dison; SCGEM; #5, 6 Tony Reed; SCGEM; #5, 6 Lloyd Barnes; SCGEM; #5, 6 Clifford Shepard; SCGEM; #5, 6 Lucius Burris; SCGEM; #5, 6 Roger Green; SCGEM; #5, 6	
The commenters who supported this addition wanted there to be something formal in place so that the RA could review the IROLs of its adjacent RAs – the intent was to ensure that there was peer review to help prevent one RA from developing its IROLs in a manner that would adversely impact its adjacent RAs.	
Al Corbet; TVA Jerry Landers; TVA Jennifer Weber; TVA Edd Forsythe; TVA Larry Goins; TVA Mark Creech; TVA Kathy Davis; TVA	RAs should coordinate and reach agreements for IROLs on joint Facilities. RAs should communicate IROLs that could impact neighboring RAs.
Agreed. However, both of these actions are addressed in the Coordinate Operations Standard. Standard 101 requires the RA to have a process, procedure or plan to address situations involving more than one RA – and Standard 102 requires the RA to notify other RAs of situations in its RA Area that may impact other RA Areas.	
Michael Zahorik; ATC; #1	Each RA should agree with the calling RA on the IRL.
If two RAs can't agree on an IROL, the standard now requires that the RAs operate to the most conservative limit.	
Raj Rana; AEP; 1,3,5,6	I suggest this standard adopt the concept included in the newly revised Policy 9, which requires the RCs to respect each others limits and operate to the most conservative position when disagreements arise.
This concept has been adopted and is reflected in the revised standard.	
William Pope; Gulf Power Co; #3	
Other Responses	
Lawrence Hochberg; NYSRC; #2	There should be a mutual agreement on the process of coordination among RAs. The process could be that both Areas calculate a separate limit for common facilities based upon the internal transmission configuration. However, the Areas agree that they will operate to the more conservative limit of the different calculation results. Furthermore, it is expected that a need for appropriate analysis/studies shall be outlined that could identify such common impacted facilities. Such requirements can be included in Standard 600.
The Determine Facility Ratings Standard does require the RA to share its SOL development methodology and the process used to identify the subset of IROLs with other RAs, and does require that RAs be responsive to comments received on the methodology used to develop IROLs. Coordination between RAs is addressed in the Coordinate Operations Standard. Several commenters indicated that this requirement is already covered in the Coordinate Operations Standard's first	

requirement, which requires RAs to have a process, procedure or plan to address situations involving more than one RA. Under the Coordinate Operations Standard, the procedure, process or plan does not need to be a formal agreement.

11. Public posting of IROLs

Several balloters requested that the SDT change the standard to include a requirement that RAs publicly post their IROLs. The SDT could not identify a reliability-related reason to support this. Do you want the standard to require public posting of IROLs?

Summary Consideration: Most industry commenters did not support the public posting of IROLs, so this change was not incorporated into the revised standard.

<table>
<tr><th colspan="2">Yes Responses</th></tr>
<tr><td>John Swanson;NPDD;2
Darrick Moe;WAPA;2
Lloyd Linke;WAPA;2
Paul Koskela; MP; 2
Larry Larson; OTP; 2
Dick Pursley; GRE; 2
Martin Trence; XCEL; 2
Todd Gosnell; OPPD; 2
Robert Coish; MH; 2
Joe Knight; MAPPCOR; 2
Tom Mielnik; MEC; 2
Dave Jacobson; MH; 2
Delyn Helm; GRE; 2
Jason Weiers; OTP; 2
Dennis Kimm; MEC; 2</td><td>This would help all entities confirm that the correct value is being used. However, confirm that public posting means posting on the OASIS in an area that registered market participants can access. For national security reasons, these values should not be posted on a web site that any Internet user can access.
.</td></tr>
<tr><td colspan="2">Most commenters were opposed to this addition and indicated that posting would not serve a reliability-related purpose.</td></tr>
<tr><td>Roman Carter; SCGEM; #5, 6
Joel Dison; SCGEM; #5, 6
Tony Reed; SCGEM; #5, 6
Lloyd Barnes; SCGEM; #5, 6
Clifford Shepard; SCGEM; #5, 6
Lucius Burris; SCGEM; #5, 6
Roger Green; SCGEM; #5, 6</td><td>Certain limit information can be beneficial to the Wholesale Market. By including appropriate levels of viewing restrictions, passwords, and security screens, etc., it could be posted without harm to physical security</td></tr>
<tr><td colspan="2">Most commenters were opposed to this addition and indicated that posting would not serve a reliability-related purpose.</td></tr>
<tr><th colspan="2">‘No’ Responses</th></tr>
<tr><td>Marc Butts; Southern Company Svcs; #1
Raymond Vice; Southern Company Svcs; #1
Dan Baisden; Southern Company Svcs; #1
Jim Griffith; Southern Company Svcs; #1
Phil Winston; Georgia Power Company; #3
Jim Viikinsalo; Southern Company Svcs; #1
Mike Miller; Southern Company Svcs; #1</td><td>If “posting” means naming the specific limiting elements then we think critical information such as this does nothing to improve reliability and may be to the detriment of Homeland Security. If this is only a ‘numeric value’ then perhaps this can be accommodated.</td></tr>
</table>

Monroe Landrum; Southern Company Svcs; #1 Gwen Frazier; Southern Company Svcs; #1 Steve Williamson; Southern Company Svcs; #1 Rod Hardiman; Southern Company Svcs; #1 Jonathan Glidewell; Southern Company Svcs; 1 Dan Richards; Southern Company Svcs; #1 Mike Hardy; Southern Company Svcs; #1 David Majors; Georgia Power Company; #3	
Most commenters were opposed to this addition and indicated that posting would not serve a reliability-related purpose	
Raj Rana; AEP; 1,3,5,6	This is a bad idea with what should be obvious infrastructure security risks associated with it. However, the business community may want to see these limits posted. There should be a mechanism for the commercial community to view such limits while observing the infrastructure security requirements.
Most commenters were opposed to this addition and indicated that posting would not serve a reliability-related purpose	
John Blazekovich; Exelon; 1,2,5,6	– We suspect the public postings of IROL's would be a dream come true for any terrorist considering an attack against the bulk power infrastructure of the United States and Canada.
Most commenters were opposed to this addition and indicated that posting would not serve a reliability-related purpose	
Al Corbet; TVA Jerry Landers; TVA Jennifer Weber; TVA Edd Forsythe; TVA Larry Goins; TVA Mark Creech; TVA Kathy Davis; TVA	We see no value in posting this and it may pose a security risk.
Most commenters were opposed to this addition and indicated that posting would not serve a reliability-related purpose	
Patti Metro; FRCC; #2 Linda Campbell ;FRCC ;#2 Steve Wallace; Seminole Electric Coop ;#4 Amy Long; Lakeland Electric; #1 Richard Gilbert; Lakeland Electric; #3 Ron Donahey; Tampa Electric Company; #3 Beth Young; Tampa Electric Company ;#3 Roger Hunnicutt ; Gainesville Reg Utl; #5 Roger Westphal ;City of Gainesville; #3 Greg Woessner ;Kissimmee Utility Auth;#3	This type of information can be considered secure Critical Infrastructure Information as well as market sensitive and should not be publicly posted.

Ben Sharma ;Kissimmee Utility Auth;#3 Garry Baker; JEA ;#1 Ed DeVarona; Florida Power & Light Co. ;#1 Preston Pierce; Progress Energy Florida ;#1 Bob Remley; Clay Electric Cooperative; #4 Joe Krupar; FMPA; #3 Paul Elwing; Lakeland Electric; #5 Joe Roos; Ocala Electric Utility ;#3	
Most commenters were opposed to this addition and indicated that posting would not serve a reliability-related purpose	
Lee Xanthakos; SCE&G; #1	NO. I agree with the SDT that there is no reliability reason to support this.
Most commenters were opposed to this addition and indicated that posting would not serve a reliability-related purpose	
Gerald Rheault; Manitoba Hydro; #1,3,5,6	There should be a requirement to provide information about IROLs to any affected entities particularly Transmission Operator, Balancing Authority and Interchange Authority.
The SAR DT that developed the SAR for Coordinate Operations suggested that there was a need for another SAR to address coordinating operations within an RA's Area.	
Michael Zahorik; ATC; #1	They can not all be determined prior to the fact. They will change. A cascade event generally requires multi elements which will increase the possiblities in a factoral fashion.
Agreed. The standard has been modified to try to add even more clarity to this concept.	
Peter Burke; ATC; #1	The RA should share those IROLs with its members and adjacent RA but public posting may prove to be overly burdensome to the RA's.
The SAR DT that developed the SAR for Coordinate Operations suggested that there was a need for another SAR to address coordinating operations within an RA's Area.	
Anita Lee; AESO; #2	The AESO supports comments of the Standards Review Committee of the ISO/RTO Council.
Please see the response to the ISO/RTO Council's comments.	
Chifong Thomas; PG&E; #1 Glenn Rounds; PG&E; #1 Ben Morris; PG&E; #1	Publicly posting IROLs could introduce market distortion. The information should be shared only with entities responsible for the reliable operation of the electric transmission system. In addition, if the IROL is to be "dynamic", this requirement may not be workable, or, even if workable, could be burdensome.
Most commenters were opposed to this addition and indicated that posting would not serve a reliability-related purpose	
William Smith; Allegheny Power; #1	Identifying the most vulnerable points of the Interconnected transmission system is an invitation to sabotage. System operating limits are appropriate for posting, but that subset of limits that are IROLs should not be identified publicly. This should be confidential information.

<table>
<tr><td colspan="2">Most commenters were opposed to this addition and indicated that posting would not serve a reliability-related purpose</td></tr>
<tr><td>James Murphy; BPAT;#1
Mike Viles; BPAT; #1
Richard Spence; BPAT; #1
Don Watkins; BPAT; #1
Don Gold; BPAT; #1
Marv Landauer; BPAT; #1</td><td>BPAT believes there is no reliability-related reason to publicly post IROLs; in fact it may be a security issue.</td></tr>
<tr><td colspan="2">Most commenters were opposed to this addition and indicated that posting would not serve a reliability-related purpose</td></tr>
<tr><td>Greg Campoli; NYISO; #2
James Castle; NYISO ;#2
John Ravalli; NYISO; #2
Karl Tammar; NYISO; #2
Robert Waldele; NYISO; #2
Michael Calimano; NYISO; #2</td><td>All RAs should be aware of all IROLs but this information may not be appropriate for the “general public”. There is a concern over infrastructure security and issues related to CIPC.</td></tr>
<tr><td colspan="2">Most commenters were opposed to this addition and indicated that posting would not serve a reliability-related purpose</td></tr>
<tr><td>R. Peter Mackin; TRANC; #1</td><td>Public posting should not be necessary as long as all entities that have a need to know the IROLs can have access to them.</td></tr>
<tr><td colspan="2">Most commenters were opposed to this addition and indicated that posting would not serve a reliability-related purpose</td></tr>
<tr><td>Alan Gale; City of Tallahassee; #5
Rusty Foster; City of Tallahassee; #3</td><td>This information can be considered secure Critical Infrastructure Information, as well as Market Sensitive, and should not be publicly posted.</td></tr>
<tr><td colspan="2">Most commenters were opposed to this addition and indicated that posting would not serve a reliability-related purpose</td></tr>
<tr><td>Jalal Babik; Dominion VA Power; #1
Craig Crider; Dominion VA Power; #1
Jack Kerr; Dominion VA Power; #1
Bill Thompson; Dominion VA Power; #1</td><td>The Transmission Owner is responsible for establishing facility ratings for its equipment. The RA function is to monitor the system according to the TO’s System Operating Limits. There is no need to publicly post the IROLs.</td></tr>
<tr><td colspan="2">Most commenters were opposed to this addition and indicated that posting would not serve a reliability-related purpose</td></tr>
<tr><td>Ed Riley; CA-ISO; #2</td><td>What does “made public” mean? All RAs should be aware of all IROLs but this information may not be appropriate for the “general public”. There is a concern over infrastructure security and some concern voiced by a CIPC member.</td></tr>
<tr><td colspan="2">The term, ‘made public’ was suggested by several commenters, not by the SDT – and the SDT did not define this term. The SDT assumed that the commenters were suggesting that the limits be posted through OASIS or a similar tool. Most commenters were opposed to this addition and indicated that posting would not serve a reliability-related purpose.</td></tr>
<tr><td>John Horakh; MAAC; #2</td><td>Public posting of IROLs is a market issue, which should be considered in any complementary NAESB</td></tr>
</table>

	standard.
Most commenters were opposed to this addition and indicated that posting would not serve a reliability-related purpose.	
Mark Fidrych; WAPA; #1	
Karl Kohlrus; City Water, Light & Power; # 5	
William Pope; Gulf Power Co; #3	
Ralph Rufrano; NYPA; #1 David Kiguel; Hydro One Networks Inc.; #1 Roger Champagne; H-Q TransÉnergie; #1 Greg Campoli; New York ISO (NYISO); #2 Peter Lebro; National Grid; #1 Kathleen Goodman; ISO-NE; #2 Dan Stosick; ISO-NE;#2 Al Adamson; NYSRC;#2 Khagan Khan; The IMO Ontario; #2 Brian Hogue; NPCC;#2 Guy Zito; NPCC;#2	
Carter Edge; SEPA ; #4 & 5 William Gaither; SC Public Svc Auth; #1 Ken Skroback; AL Elec Coop ; #1 Roger Brand; Muni Elec Auth of GA; #1 Phil Creech; Progress Energy - Carolinas; #1 Gene Delk; SCE&G; #1 Al McMeekin; SCE&G; #1 Randy Hunt; Dominion – VA Pwr; #1 Doug Newbauer; GA System Ops; #1 Mike Clements; TVA; #1 Don Reichenbach; Duke Energy; #1 Lynna Estep; SERC; #2 Dan Kay; S Mississippi Elec Pwr Assoc; #1 Matt Ansley; Southern Company; #1 Uma Gangadharan; Entergy; #1	
Kathleen Goodman; ISO-NE; #2	
Khaqan Khan; IMO; #2	
Lawrence Hochberg; NYSRC; #2	
Ed Davis; Entergy Services; #1	
Richard Kafka; Pepco; #3	
Ken Githens; Allegheny Energy ; #5	
Dan Boezio; AEP; #1 Ron Ciesiel; SPP; #2 Bob Cochran; SPS; #1	

Mike Gammon; KCP&L; #1 Allen Klassen; Westar; #1 Peter Kuebeck; OG&E; #1 Mike Stafford; GRDA; #1 Robert Rhodes; SPP; #2 Scott Moore; AEP; #1	
Other Responses	
Dale McMaster; AESO; #2 Ed Riley; CAISO; #2 Sam Jones; ERCOT; #2 Don Tench ; IMO; #2 Dave LaPlante; ISO_NE; #2 William Phillips; MISO; #2 Karl Tammar; NYISO; #2 Bruce Balmat; PJM; #2 Carl Monroe; SPP ; #2	What does “made public” mean? All RAs should be aware of all IROLs but this information may not be appropriate for the “general public”. There is a concern over infrastructure security and some concern voiced by a CIPC member.
The term, ‘made public’ was suggested by several commenters, not by the SDT – and the SDT did not define this term. The SDT assumed that the commenters were suggesting that the limits be posted through OASIS or a similar tool. Most commenters were opposed to this addition and indicated that posting would not serve a reliability-related purpose.	

12. **Other comments about Requirement 201:**

Summary Consideration: Requirement 201 has been removed from this standard and absorbed into the Determine Facility Ratings, System Operating Limits and Transfer Capabilities Standard.

Ken Githens; Allegheny Energy; #5	To determine every scenario that would lead to an IROL's ahead of time is a problem.
This requirement has been absorbed into the Determine Facility Ratings, System Operating Limits and Transfer Capabilities Standard (DFR Standard). The DFR Standard includes specific criteria for establishing SOLs and identifying the subset of SOLs that are also IROLs. This should minimize the number of scenarios that must be considered in determining whether an SOL is also an IROL.	
James Murphy; BPAT;#1 Mike Viles; BPAT; #1 Richard Spence; BPAT; #1 Don Watkins; BPAT; #1 Don Gold; BPAT; #1 Marv Landauer; BPAT; #1	201(d) & (e) (3) (ii) need to be changed to correspond more with (b) (1) (i). Which includes adding "to reflect changes in its Reliability Authority Area's system topology.
This requirement has been absorbed into the Determine Facility Ratings, System Operating Limits and Transfer Capabilities Standard (DFR Standard). The DFR Standard requires that SOLs (and identification of which SOLs are also IROLs) be developed according to a methodology that meets specific criteria – and one of the criteria is that the limits reflect changes to system topology.	
Gerald Rheault; Manitoba Hydro; #1,3,5,6	1. There needs to be a reference in 201 that the determination of IROLs should be consistent with Standard 600. In Standard 600 it should be explicitly required for the RA to demonstrate it has the tools, procedures and trained staff to do the required studies. The link between an Interconnection Reliability Operating Limit and the limits defined in standard 600 is tenuous – especially as the term "system operating limits" is not capitalized nor is there a reference to standard 600 in the definitions. Without that link, an IROL could be seen as a limit even in steady state (there is no contingency clearly associated with the definition – the consideration of contingencies is buried in standard 603). Presumably the link is believed to be made by calling IROLs a subset of SOL's. While Manitoba Hydro still believes that such limits are not a subset of SOL's but, rather, new limits based on similar studies, but with different criteria for acceptable performance (i.e., limits may be exceeded but cascading, instability and uncontrolled separation are BARELY avoided) there is value in discussing the IROL concept as put forward by the OWL team. 2. In standard 600, SOL's are established through consideration of all next single contingencies and for some regions, all multiple contingencies and for others, a set of credible multiple contingencies. Universally, a SOL must be established to avoid cascading, instability and uncontrolled separation. The question for the OWL group to consider is – how

	does standard 200 deal with the fact that in thermally-limited systems the margin between the SOL and cascading, etc.l, may be very large, while in stability-limited systems, there will still be some reliability margin, likely not a large one, between the SOL and the onset of cascading, etc. Thus the risk of a problem if an SOL is violated is a function of the nature of the limit itself- the risk associated with stability limits is likely higher than for thermal limits. 3. Of the list of nasty events, the risk of instability and uncontrolled separation will be fairly evident from stability studies but the risk of cascading is dependent on thermal ratings, thermal overload and operator action to some extent. Since the SOL definition allows for system readjustments, while requiring limits not be exceeded, the risk of cascading increases if the required adjustments are not undertaken – and these may not be automatic actions. Note that the Standard 600 assumes that qualified ratings will be provided for all facilities (i.e., the rating value will have an associated time period – perhaps 15 minute, 2 hour, etc.) so that facilities ratings are assumed to be respected – there could be an exception in the case of credible multiple contingencies, where a region may tolerate some facility violation if it can be managed expeditiously and not lead to cascading – MAPP presently does this although the ratings being exceeded in the checking process are likely the long term values, not the short term values). Since the Q&A document talks about increased RISK of cascading, rather than occurrence of cascading, the OWL team needs to clarify this potential source of confusion – there will almost always be increased risk of a problem as loadings increase or are left unchanged – but that opens the door to IROL evaluation having ton consider the impacts of failures of the operator, etc. As such, any limit in the system could be considered an IROL, since, for some combination of contingencies, the unacceptable consequences could be seen. In fact, you could even consider the definition of an IROL as a steady state limit. 4. If the OWL team is adamant that IROLs are a subset of SOL's then the rest of Standard 200 should be reviewed to ensure that risks are properly considered in the measurements and compliance process – right now some entities might be penalized for low risk events. One way to manage the discrepancy would be for

	IROLs to be established at a known margin from the nasty three events – so the IROL for a thermally-limited system might be significantly higher than the corresponding SOL. 5. Until there is more clarity on the definition of an IROL, the implementation plan is suspect when it addresses the current state – there is a good chance IROLs are not being identified and calculated now, as expected by the standard. 6. Manitoba Hydro is greatly concerned relative to the statement in the Q&A document regarding special protection schemes since the response to the question indicates that the special protection system should basically be ignored. The reality in MAPP is that such systems are put in place with a high degree of reliability and with the expectation that they will not fail. If Manitoba Hydro had to live with the situation as outlined in the response, we would be in violation every time we export more than, perhaps 500 MW rather than the 2000 MW we can export presently. Is that really what the response was meant to say; or is the response rally saying that you should know what the limits are if the special protection is out of service and respect those limits?

1. This requirement has been absorbed into the Determine Facility Ratings, System Operating Limits and Transfer Capabilities Standard (DFR Standard). The DFR Standard requires that SOLs (and identification of which SOLs are also IROLs) be developed according to a methodology that meets specific criteria.

2. The SDT recognizes that there are different types of IROLs, and that some systems may be more thermally-rated than others. The intent is not to 'equalize' all IROLs across systems, but to ensure that no system operates such that exceeding a limit could cause cascading outages, etc. Each RA has flexibility in setting T_v to an appropriate value for the associated limit. In some Regions, some IORLs have a 20 minute T_v, while other IORLs have a T_v of 30 minutes. This variation in time recognizes that stability-related limits may need a response time that is different from thermally-related limits.

3. Each RA and Planning Authority is allowed to design its own SOL development methodology. The individual methodologies are expected to be appropriate for the associated systems. An RA that is responsible for a system that is stability-limited may require additional studies beyond those that are required in the methodology used for a thermally-limited system. There is nothing in Standard 600 to preclude this – Standard 600 was designed to allow this flexibility in SOL development methodologies. All methodologies must, however, result in limits that meet the specified criteria.

4. The SDT revised the standard to remove the phrase, "loss of 300 MW … for 15 minutes." With this change, the measures do not seem to be inappropriate.

5. Reliability Coordinators have been field-testing the reporting of IRL violations for several months. Most recently, the OLDTF conducted a survey to determine how each RC is developing its IORLs, and it was clear from the responses that there is no standard methodology, but that each RC does have a methodology for identifying its IORLs.

6. This standard neither requires nor precludes the use of an SPS to resolve an IROL within T_v.

The reference was intended to say that the system operator needs to know that if the SPS doesn't work, the IROL will be exceeded and the system operator needs to be prepared to take action or to direct others to act without delay.

Questions about Requirement 202 — Monitoring

13. Provide system operators with additional data on each IROL

Several balloters recommended the following addition to this requirement. Do you agree with this addition?

(i) The RA shall provide the following information to its system operators:
- (a) The system conditions under which the Interconnection Reliability Operating Limit applies,
- (b) The contingency that is the basis for the limit,
- (c) The impact of exceeding the limit

Summary Consideration: Most industry commenters agreed with this addition. Some commenters questioned the feasibility of providing this information to system operators in 'real-time'. With the transfer of the requirement to identify and communicate IROLs to the Determine Facility Ratings (DFR) Standard, the OWL Standard does not include the above language. The DFR Standard did absorb the requirement to provide supporting information for each IROL – however the DFR Standard does not specifically state that IROLs must be updated in 'real-time'. The DFR Standard requires that entities needing IROLs make a request that includes a schedule for delivery – and requires the RA to deliver the limits according to that schedule.

Standard 604 – Requirement 4 (i) The Reliability Authority shall provide its System Operating Limits (including the subset of System Operating Limits that are Interconnection Reliability Operating Limits) to adjacent Reliability Authorities and Reliability Authorities who indicate a reliability-related need for those limits, and to the Transmission Operators, Transmission Service Providers and Planning Authorities within its Reliability Authority Area. For each Interconnection Reliability Operating Limit, the Reliability Authority shall provide the following supporting information:

A) Identification and status of the associated Facility (or group of Facilities) that is (are) critical to the derivation of the Interconnection Reliability Operating Limit.

B) The value of the Interconnected Reliability Operating Limit and its associated T_v.

C) The associated contingency(ies).

D) The type of limitation represented by the Interconnection Reliability Operating Limit (e.g., voltage collapse, angular stability).

'Yes' Responses	
Ken Githens; Allegheny Energy; #5	However, under Requirements 203 or 204 would be a better place to include the addition.
This requirement to provide this information with each IROL has been transferred to the DFR Standard.	
Gerald Rheault; Manitoba Hydro; #1,3,5,6	The wording of (a) could be improved. Suggest: "The system conditions under which exceeding the Interconnection Reliability Operating Limit could lead to instability, uncontrolled separation or cascading outages." As is, the wording of (a) could be interpreted to mean that it is ok to exceed the IROL under other system conditions. Suggest also that stating these items be required in the determination of all System Operating Limits (applicable to Standard 600).

This requirement to provide this information with each IROL has been transferred to the DFR Standard.	
Patti Metro; FRCC; #2 Linda Campbell ;FRCC ;#2 Steve Wallace; Seminole Electric Coop ;#4 Amy Long; Lakeland Electric; #1 Richard Gilbert; Lakeland Electric; #3 Ron Donahey; Tampa Electric Company; #3 Beth Young; Tampa Electric Company ;#3 Roger Hunnicutt ; Gainesville Reg Utl; #5 Roger Westphal ;City of Gainesville; #3 Greg Woessner ;Kissimmee Utility Auth;#3 Ben Sharma ;Kissimmee Utility Auth;#3 Garry Baker; JEA ;#1 Ed DeVarona; Florida Power & Light Co. ;#1 Preston Pierce; Progress Energy Florida ;#1 Bob Remley; Clay Electric Cooperative; #4 Joe Krupar; FMPA; #3 Paul Elwing; Lakeland Electric; #5 Joe Roos; Ocala Electric Utility ;#3	It is very important for the system operator to have as much information available as possible to make decisions to ensure system reliability.
Most commenters agreed with you and the DFR SDT has added this requirement to the DFR standard.	
Khaqan Khan; IMO; #2	We agree with these requirements and recommend that these should be specifically included in the standard 200.
Most commenters agreed with you and the DFR SDT has added this requirement to the DFR standard.	
Greg Campoli; NYISO; #2 James Castle; NYISO ;#2 John Ravalli; NYISO; #2 Karl Tammar; NYISO; #2 Robert Waldele; NYISO; #2 Michael Calimano; NYISO; #2 Ralph Rufrano; NYPA; #1 David Kiguel; Hydro One Networks Inc.; #1 Roger Champagne; H-Q TransÉnergie; #1 Greg Campoli; New York ISO (NYISO); #2 Peter Lebro; National Grid; #1 Kathleen Goodman; ISO-NE; #2 Dan Stosick; ISO-NE;#2 Al Adamson; NYSRC;#2 Khagan Khan; The IMO Ontario; #2 Brian Hogue; NPCC;#2 Guy Zito; NPCC;#2 Lawrence Hochberg; NYSRC; #2	This is a desirable addition, and should appear consistently throughout the document

Most commenters agreed with you and the DFR SDT has added this requirement to the DFR standard.	
Lee Xanthakos; SCE&G; #1	I agree with proving the system controllers with as much information as possible without overloading them. If the SDT believes that this information aggregated with all the other information System controllers get would not be to much to handle then I'll agree with this requirements.
The DFR SDT has added this requirement to the DFR standard. This data does not need to be provided in the form of a 'report' – the data could be provided electronically and available on an 'as requested' basis.	
Karl Kohlrus; City Water, Light & Power; # 5	
John Blazekovich; Exelon; 1,2,5,6	
Raj Rana; AEP; 1,3,5,6	
William Pope; Gulf Power Co; #3	
Michael Zahorik; ATC; #1	
Dale McMaster; AESO; #2 Ed Riley; CAISO; #2 Sam Jones; ERCOT; #2 Don Tench ; IMO; #2 Dave LaPlante; ISO_NE; #2 William Phillips; MISO; #2 Karl Tammar; NYISO; #2 Bruce Balmat; PJM; #2 Carl Monroe; SPP ; #2	
Anita Lee; AESO; #2	
John Swanson;NPDD;2 Darrick Moe;WAPA;2 Lloyd Linke;WAPA;2 Paul Koskela; MP; 2 Larry Larson; OTP; 2 Dick Pursley; GRE; 2 Martin Trence; XCEL; 2 Todd Gosnell; OPPD; 2 Robert Coish; MH; 2 Joe Knight; MAPPCOR; 2 Tom Mielnik; MEC; 2 Dave Jacobson; MH; 2 Delyn Helm; GRE; 2 Jason Weiers; OTP; 2 Dennis Kimm; MEC; 2	
Chifong Thomas; PG&E; #1 Glenn Rounds; PG&E; #1 Ben Morris; PG&E; #1	

William Smith; Allegheny Power; #1	
Al Corbet; TVA Jerry Landers; TVA Jennifer Weber; TVA Edd Forsythe; TVA Larry Goins; TVA Mark Creech; TVA Kathy Davis; TVA	
Carter Edge; SEPA ; #4 & 5 William Gaither; SC Public Svc Auth; #1 Ken Skroback; AL Elec Coop ; #1 Roger Brand; Muni Elec Auth of GA; #1 Phil Creech; Progress Energy - Carolinas; #1 Gene Delk; SCE&G; #1 Al McMeekin; SCE&G; #1 Randy Hunt; Dominion – VA Pwr; #1 Doug Newbauer; GA System Ops; #1 Mike Clements; TVA; #1 Don Reichenbach; Duke Energy; #1 Lynna Estep; SERC; #2 Dan Kay; S Mississippi Elec Pwr Assoc; #1 Matt Ansley; Southern Company; #1 Uma Gangadharan; Entergy; #1	
Kathleen Goodman; ISO-NE; #2	
Marc Butts; Southern Company Svcs; #1 Raymond Vice; Southern Company Svcs; #1 Dan Baisden; Southern Company Svcs; #1 Jim Griffith; Southern Company Svcs; #1 Phil Winston; Georgia Power Company; #3 Jim Viikinsalo; Southern Company Svcs; #1 Mike Miller; Southern Company Svcs; #1 Monroe Landrum; Southern Company Svcs; #1 Gwen Frazier; Southern Company Svcs; #1 Steve Williamson; Southern Company Svcs; #1 Rod Hardiman; Southern Company Svcs; #1 Jonathan Glidewell; Southern Company Svcs; 1 Dan Richards; Southern Company Svcs; #1 Mike Hardy; Southern Company Svcs; #1 David Majors; Georgia Power Company; #3	
R. Peter Mackin; TRANC; #1	
Jalal Babik; Dominion VA Power; #1	

Craig Crider; Dominion VA Power; #1 Jack Kerr; Dominion VA Power; #1 Bill Thompson; Dominion VA Power; #1	
Ed Riley; CA-ISO; #2	
John Horakh; MAAC; #2	
Richard Kafka; Pepco; #3	
Dan Boezio; AEP; #1 Ron Ciesiel; SPP; #2 Bob Cochran; SPS; #1 Mike Gammon; KCP&L; #1 Allen Klassen; Westar; #1 Peter Kuebeck; OG&E; #1 Mike Stafford; GRDA; #1 Robert Rhodes; SPP; #2 Scott Moore; AEP; #1	
Ed Davis; Entergy Services; #1	
Alan Gale; City of Tallahassee; #5 Rusty Foster; City of Tallahassee; #3	
Roman Carter; SCGEM; #5, 6 Joel Dison; SCGEM; #5, 6 Tony Reed; SCGEM; #5, 6 Lloyd Barnes; SCGEM; #5, 6 Clifford Shepard; SCGEM; #5, 6 Lucius Burris; SCGEM; #5, 6 Roger Green; SCGEM; #5, 6	
'No' Responses	
Mark Fidrych; WAPA; #1	Under dynamic conditions this is impossible to accomplish
The data does not need to be provided as part of a paper document – this may be provided electronically.	
James Murphy; BPAT;#1 Mike Viles; BPAT; #1 Richard Spence; BPAT; #1 Don Watkins; BPAT; #1 Don Gold; BPAT; #1 Marv Landauer; BPAT; #1	We agree if (c) is omitted. We believe it would be unrealistic to give the system operators the impact of exceeding the limit for every scenario.
This requirement was transferred to the DFR Standard. Additional language was added to clarify (c).	
Other Comments	
Peter Burke; ATC; #1	We have not indicated a yes or no because the question is confusing. This addition does not appear in the 202 standard that this comment form accompanies. If you are asking if this should be

	added but has not been currently added to the standard, then ATC's opinion is that this should appear in the standard. The only suggestion is that item "(c)" is not needed. The idea behind moving an SOL into the IROL category is that it has a high potential to cause an adverse impact to the Interconnection.

The SDT wasn't sure if the industry would support this addition, so it was not added to the version of the standard that was posted for comment.

In category (c), the entities that currently provide this information to their system operators indicate whether exceeding the IROL will lead to transient stability, voltage decline, etc. The entities currently providing this information to their system operators feel that this information helps the system operator make appropriate decisions.

Questions about Requirement 204 — Actions

14. Indicate that directive is related to an IROL

Several balloters commented about the level of documentation required in this standard. The SDT noted that without additional clarification, the entity that receives an RA's directive may not realize that the directive is related to an IROL. To improve the 'situational awareness' of directives related to IROLs, the SDT added this requirement. Do you agree with the addition of this requirement?

> Each directive issued relative to an IROL shall include a statement to inform the recipient that the directive is related to an IROL

Summary Consideration: Most industry commenters agreed with this addition. Those commenters who disagreed felt that this addition might be interpreted as implying that some RA directives are more important and should be followed more closely than other RA directives. This was not the intent of this requirement.

Yes Responses	
Marc Butts; Southern Company Svcs; #1 Raymond Vice; Southern Company Svcs; #1 Dan Baisden; Southern Company Svcs; #1 Jim Griffith; Southern Company Svcs; #1 Phil Winston; Georgia Power Company; #3 Jim Viikinsalo; Southern Company Svcs; #1 Mike Miller; Southern Company Svcs; #1 Monroe Landrum; Southern Company Svcs; #1 Gwen Frazier; Southern Company Svcs; #1 Steve Williamson; Southern Company Svcs; #1 Rod Hardiman; Southern Company Svcs; #1 Jonathan Glidewell; Southern Company Svcs; 1 Dan Richards; Southern Company Svcs; #1 Mike Hardy; Southern Company Svcs; #1 David Majors; Georgia Power Company; #3 Roman Carter; SCGEM; #5, 6 Joel Dison; SCGEM; #5, 6 Tony Reed; SCGEM; #5, 6 Lloyd Barnes; SCGEM; #5, 6 Clifford Shepard; SCGEM; #5, 6 Lucius Burris; SCGEM; #5, 6 Roger Green; SCGEM; #5, 6	This helps to identify the message as to relate to an IROL.
This is what was intended.	
Raj Rana; AEP; 1,3,5,6	Clear and concise communications is always the preference. However, implied in this statement above, is that if the RC issues a directive and does not state it is related to an IROL, then the responsible RA is cleared of all fault, etc. if the RAI delays in following the directive. This is disturbing and part of

	the reason for some of the language change in the newly revised Policy 5 & 9. From newly revised Policy 5: Complying with Reliability Coordinator directives. The Operating Authority shall comply with Reliability Coordinator directives unless such actions would violate safety, equipment, or regulatory or statutory requirements. Under these circumstances the Operating Authority must immediately inform the Reliability Coordinator of the inability to perform the directive so that the Reliability Coordinator can implement alternate remedial actions.
Other standards contain similar requirements for following RA directives. If the RA allows operations within its RA Area to exceed an IROL for time greater than T_v, then that RA is sanctioned. The most severe sanction in this standard is linked to the RA's performance in managing operations without exceeding an IROL for time within T_v – there are no sanctions applied to the RA for not mentioning that a directive is related to an IROL. The suggested language from the newly approved Policy 5 has been adopted and is reflected in the revised standard.	
Michael Zahorik; ATC; #1	This information should be issued to the System Operator when the IRL is issued
Agreed. This is what was intended.	
Lee Xanthakos; SCE&G; #1	
Karl Kohlrus; City Water, Light & Power; # 5	
John Blazekovich; Exelon; 1,2,5,6	
William Pope; Gulf Power Co; #3	
James Murphy; BPAT;#1 Mike Viles; BPAT; #1 Richard Spence; BPAT; #1 Don Watkins; BPAT; #1 Don Gold; BPAT; #1 Marv Landauer; BPAT; #1	
Gerald Rheault; Manitoba Hydro; #1,3,5,6	
Patti Metro; FRCC; #2 Linda Campbell ;FRCC ;#2 Steve Wallace; Seminole Electric Coop ;#4 Amy Long; Lakeland Electric; #1 Richard Gilbert; Lakeland Electric; #3 Ron Donahey; Tampa Electric Company; #3 Beth Young; Tampa Electric Company ;#3 Roger Hunnicutt ; Gainesville Reg Utl; #5 Roger Westphal ;City of Gainesville; #3 Greg Woessner ;Kissimmee Utility Auth;#3 Ben Sharma ;Kissimmee Utility Auth;#3 Garry Baker; JEA ;#1	

Ed DeVarona; Florida Power & Light Co. ;#1 Preston Pierce; Progress Energy Florida ;#1 Bob Remley; Clay Electric Cooperative; #4 Joe Krupar; FMPA; #3 Paul Elwing; Lakeland Electric; #5 Joe Roos; Ocala Electric Utility ;#3	
Peter Burke; ATC; #1	
Mark Fidrych; WAPA; #1	
Chifong Thomas; PG&E; #1 Glenn Rounds; PG&E; #1 Ben Morris; PG&E; #1	
William Smith; Allegheny Power; #1	
Carter Edge; SEPA ; #4 & 5 William Gaither; SC Public Svc Auth; #1 Ken Skroback; AL Elec Coop ; #1 Roger Brand; Muni Elec Auth of GA; #1 Phil Creech; Progress Energy - Carolinas; #1 Gene Delk; SCE&G; #1 Al McMeekin; SCE&G; #1 Randy Hunt; Dominion – VA Pwr; #1 Doug Newbauer; GA System Ops; #1 Mike Clements; TVA; #1 Don Reichenbach; Duke Energy; #1 Lynna Estep; SERC; #2 Dan Kay; S Mississippi Elec Pwr Assoc; #1 Matt Ansley; Southern Company; #1 Uma Gangadharan; Entergy; #1	
R. Peter Mackin; TRANC; #1	
Jalal Babik; Dominion VA Power; #1 Craig Crider; Dominion VA Power; #1 Jack Kerr; Dominion VA Power; #1 Bill Thompson; Dominion VA Power; #1	
Richard Kafka; Pepco; #3	
Ken Githens; Allegheny Energy; #5	
Ed Davis; Entergy Services; #1	
Alan Gale; City of Tallahassee; #5 Rusty Foster; City of Tallahassee; #3	
John Swanson;NPDD;2 Darrick Moe;WAPA;2 Lloyd Linke;WAPA;2 Paul Koskela; MP; 2	

<table>
<tr><td>Larry Larson; OTP; 2
Dick Pursley; GRE; 2
Martin Trence; XCEL; 2
Todd Gosnell; OPPD; 2
Robert Coish; MH; 2
Joe Knight; MAPPCOR; 2
Tom Mielnik; MEC; 2
Dave Jacobson; MH; 2
Delyn Helm; GRE; 2
Jason Weiers; OTP; 2
Dennis Kimm; MEC; 2</td><td></td></tr>
<tr><td>Dan Boezio; AEP; #1
Ron Ciesiel; SPP; #2
Bob Cochran; SPS; #1
Mike Gammon; KCP&L; #1
Allen Klassen; Westar; #1
Peter Kuebeck; OG&E; #1
Mike Stafford; GRDA; #1
Robert Rhodes; SPP; #2
Scott Moore; AEP; #1</td><td></td></tr>
<tr><td>John Horakh; MAAC; #2</td><td></td></tr>
<tr><td colspan="2">‘No’ Responses</td></tr>
<tr><td>Ed Riley; CA-ISO; #2</td><td>All directives issued by an RA must be followed without question, no matter what the circumstances. The explanations can be provided after actions have been taken and the problem solved. While we agree that if time permits a reason should be provided, the directive must be followed whether or not a reason is provided.</td></tr>
<tr><td colspan="2">Agree that it is important that entities respond to all RA directives and that the RA may not always have time to provide a reason for the directive. However, the intent here was to provide the recipient with additional ‘situational knowledge.’</td></tr>
<tr><td>Dale McMaster; AESO; #2
Ed Riley; CAISO; #2
Sam Jones; ERCOT; #2
Don Tench ; IMO; #2
Dave LaPlante; ISO_NE; #2
William Phillips; MISO; #2
Karl Tammar; NYISO; #2
Bruce Balmat; PJM; #2
Carl Monroe; SPP ; #2
Anita Lee; AESO; #2</td><td>All directives issued by an RA must be followed without question, no matter what the circumstances. The explanations can be provided after actions have been taken and the problem solved.</td></tr>
<tr><td colspan="2">Agree that it is important that entities respond to all RA directives and that the RA may not always have</td></tr>
</table>

time to provide a reason for the directive. However, the intent here was to provide the recipient with additional 'situational knowledge.'	
Ralph Rufrano; NYPA; #1 David Kiguel; Hydro One Networks Inc.; #1 Roger Champagne; H-Q TransÉnergie; #1 Greg Campoli; New York ISO (NYISO); #2 Peter Lebro; National Grid; #1 Kathleen Goodman; ISO-NE; #2 Dan Stosick; ISO-NE;#2 Al Adamson; NYSRC;#2 Khagan Khan; The IMO Ontario; #2 Brian Hogue; NPCC;#2 Guy Zito; NPCC;#2 Greg Campoli; NYISO; #2 James Castle; NYISO ;#2 John Ravalli; NYISO; #2 Karl Tammar; NYISO; #2 Robert Waldele; NYISO; #2 Michael Calimano; NYISO; #2	All directives should be acted on irrespective if they are IROL or not. Statements such as this perhaps might be better documented in the Coordinate Operation Standards.
Agree that it is important that entities respond to all RA directives and that the RA may not always have time to provide a reason for the directive. However, the intent here was to provide the recipient with additional 'situational knowledge.'	
Kathleen Goodman; ISO-NE; #2	We agree that the directive should include notice that a potential or actual contingency requires actions to correct the problem. We do not think that the use of the specific term is required.
Most industry commenters supported the requirement that the directive include the phrase, "IROL." This concept was supported by the Blackout Report.	
Lawrence Hochberg; NYSRC; #2	All directives should be acted on irrespective if they are IROL or not. Statements such as this perhaps might be better documented in the Coordinate Operation Standard.
The Coordinate Operations standard addresses RA to RA coordination, and doesn't address coordination of actions within an RA's Area.	
Khaqan Khan; IMO; #2	All directives issued by an Reliability Authority must be followed
Agree that it is important that entities respond to all RA directives and that the RA may not always have time to provide a reason for the directive. However, the intent here was to provide the recipient with additional 'situational knowledge.'	
Al Corbet; TVA Jerry Landers; TVA Jennifer Weber; TVA Edd Forsythe; TVA Larry Goins; TVA Mark Creech; TVA Kathy Davis; TVA	

15. Measuring duration of an IROL event

Some balloters suggested that the SDT modify the criteria for determining the duration of an IROL event. The language currently in the standard is shown below. One balloter suggested that the '30 seconds' be modified to '1 minute' – another balloter suggested that a longer duration should be required and suggested 10 minutes. The 30 seconds was intended to represent the maximum duration associated with a 'bad telemetry scan.'

> The duration of the event shall be measured from the point when the limit is exceeded to the point when the system has returned to a state that is within the Interconnection Reliability Operating Limit for a minimum of 30 seconds.

Summary Consideration: There was no consensus in response to this question. Some commenters responded to this question by indicating the maximum duration of a telemetry error – others responded to the question by indicating how long before the RA's system were considered to be 'stable'. While there was no consensus, more commenters selected 30 seconds than any other timeframe, so the SDT did not change this in the standard. There were commenters who indicated the duration should have a 'deadband' at the beginning as well as at the end of the duration, and the standard was modified to reflect this suggestion.

Keep minimum of 30 seconds	
Marc Butts; Southern Company Svcs; #1 Raymond Vice; Southern Company Svcs; #1 Dan Baisden; Southern Company Svcs; #1 Jim Griffith; Southern Company Svcs; #1 Phil Winston; Georgia Power Company; #3 Jim Viikinsalo; Southern Company Svcs; #1 Mike Miller; Southern Company Svcs; #1 Monroe Landrum; Southern Company Svcs; #1 Gwen Frazier; Southern Company Svcs; #1 Steve Williamson; Southern Company Svcs; #1 Rod Hardiman; Southern Company Svcs; #1 Jonathan Glidewell; Southern Company Svcs; 1 Dan Richards; Southern Company Svcs; #1 Mike Hardy; Southern Company Svcs; #1 David Majors; Georgia Power Company; #3	One additional thought is to employ a deadband on both ends of the IROL violation (so that a value must be outside IROL for thirty seconds before it becomes and IROL violation). This would help avoid metering system errors triggering either the beginning or ending of an IROL.
The SDT adopted this concept and it is reflected in the revised standard.	
James Murphy; BPAT;#1 Mike Viles; BPAT; #1 Richard Spence; BPAT; #1 Don Watkins; BPAT; #1 Don Gold; BPAT; #1 Marv Landauer; BPAT; #1	We agree with either 30 seconds or 1 minute, but 10 minutes is to long.
Most commenters agreed with keeping the '30 seconds'.	
Lawrence Hochberg; NYSRC; #2	

John Blazekovich; Exelon; 1,2,5,6	
William Pope; Gulf Power Co; #3	
Gerald Rheault; Manitoba Hydro; #1,3,5,6	
Mark Fidrych; WAPA; #1	
William Smith; Allegheny Power; #1	
Peter Burke; ATC; #1	
Chifong Thomas; PG&E; #1 Glenn Rounds; PG&E; #1 Ben Morris; PG&E; #1	
Ralph Rufrano; NYPA; #1 David Kiguel; Hydro One Networks Inc.; #1 Roger Champagne; H-Q TransÉnergie; #1 Greg Campoli; New York ISO (NYISO); #2 Peter Lebro; National Grid; #1 Kathleen Goodman; ISO-NE; #2 Dan Stosick; ISO-NE;#2 Al Adamson; NYSRC;#2 Khagan Khan; The IMO Ontario; #2 Brian Hogue; NPCC;#2 Guy Zito; NPCC;#2	
Al Corbet; TVA Jerry Landers; TVA Jennifer Weber; TVA Edd Forsythe; TVA Larry Goins; TVA Mark Creech; TVA Kathy Davis; TVA	
R. Peter Mackin; TRANC; #1	
Jalal Babik; Dominion VA Power; #1 Craig Crider; Dominion VA Power; #1 Jack Kerr; Dominion VA Power; #1 Bill Thompson; Dominion VA Power; #1	
Roman Carter; SCGEM; #5, 6 Joel Dison; SCGEM; #5, 6 Tony Reed; SCGEM; #5, 6 Lloyd Barnes; SCGEM; #5, 6 Clifford Shepard; SCGEM; #5, 6 Lucius Burris; SCGEM; #5, 6 Roger Green; SCGEM; #5, 6	
Change minimum to 1 minute	
John Horakh; MAAC; #2	Changing to 1 minute gives better assurance of good

	telemetry and allows for the system to settle more.
The intent was simply to exclude telemetry errors, not to ensue that the system had settled. Most commenters indicated a preference for 30 seconds, so this is what was adopted in the standard.	
Richard Kafka; Pepco; #3	One minute is a clearer indication that conditions have settled and that telemetry has kept up with actual conditions.
The intent was simply to exclude telemetry errors, not to ensue that the system had settled. Most commenters indicated a preference for 30 seconds, so this is what was adopted in the standard.	
Lee Xanthakos; SCE&G; #1	I believe the 1 minute limit is reasonable and stays in line with other standards under development.
The SDT working on the Balance Resources and Demand standard has a similar duration, and that SDT has agreed to adopt whatever timing requirement was indicated by the majority of the industry commenters. Most commenters indicated a preference for 30 seconds, so this is what was adopted in the standard.	
Karl Kohlrus; City Water, Light & Power; # 5	
Greg Campoli; NYISO; #2 James Castle; NYISO ;#2 John Ravalli; NYISO; #2 Karl Tammar; NYISO; #2 Robert Waldele; NYISO; #2 Michael Calimano; NYISO; #	
Ken Githens; Allegheny Energy; #5	
John Swanson;NPDD;2 Darrick Moe;WAPA;2 Lloyd Linke;WAPA;2 Paul Koskela; MP; 2 Larry Larson; OTP; 2 Dick Pursley; GRE; 2 Martin Trence; XCEL; 2 Todd Gosnell; OPPD; 2 Robert Coish; MH; 2 Joe Knight; MAPPCOR; 2 Tom Mielnik; MEC; 2 Dave Jacobson; MH; 2 Delyn Helm; GRE; 2 Jason Weiers; OTP; 2 Dennis Kimm; MEC; 2	
Change minimum to 10 minutes	
Dan Boezio; AEP; #1 Ron Ciesiel; SPP; #2 Bob Cochran; SPS; #1 Mike Gammon; KCP&L; #1 Allen Klassen; Westar; #1	Refer to our comment to Question 5. Something on the order of 5-10 minutes may be a better indicator of true system recovery.

Peter Kuebeck; OG&E; #1 Mike Stafford; GRDA; #1 Robert Rhodes; SPP; #2 Scott Moore; AEP; #1	
The intent was to exclude telemetry errors, not to provide an indicator of true system recovery. Most commenters indicated a preference for 30 seconds, so this is what was used in the standard.	
Raj Rana; AEP; 1,3,5,6	Something on the order of 5-10 minutes may be a better indicator of true system recovery.
The intent was to exclude telemetry errors, not to provide an indicator of true system recovery. Most commenters indicated a preference for 30 seconds, so this is what was used in the standard.	
Ed Davis; Entergy Services; #1	
Carter Edge; SEPA ; #4 & 5 William Gaither; SC Public Svc Auth; #1 Ken Skroback; AL Elec Coop ; #1 Roger Brand; Muni Elec Auth of GA; #1 Phil Creech; Progress Energy - Carolinas; #1 Gene Delk; SCE&G; #1 Al McMeekin; SCE&G; #1 Randy Hunt; Dominion – VA Pwr; #1 Doug Newbauer; GA System Ops; #1 Mike Clements; TVA; #1 Don Reichenbach; Duke Energy; #1 Lynna Estep; SERC; #2 Dan Kay; S Mississippi Elec Pwr Assoc; #1 Matt Ansley; Southern Company; #1 Uma Gangadharan; Entergy; #1	
Other Comments	
Ed Riley; CA-ISO; #2	The CAISO would like to see a value remain below its limit for two minutes with the understanding that if the value remains below the limit for two minutes, the reported end of the event or violation occurs at the time the value actually dropped below the limit.
Most commenters indicated a preference for 30 seconds, so this is what was used in the standard. The duration of the event would be measured as you've indicated, except that it would end at the point in time when the value reached the limit – there isn't a requirement to drop below the limit.	
Dale McMaster; AESO; #2 Ed Riley; CAISO; #2 Sam Jones; ERCOT; #2 Don Tench ; IMO; #2 Dave LaPlante; ISO_NE; #2 William Phillips; MISO; #2 Karl Tammar; NYISO; #2 Bruce Balmat; PJM; #2	The SRC would like to see a value remain below its limit for two minutes with the understanding that if the value remains below the limit for two minutes, the reported end of the event or violation occurs at the time the value actually dropped below the limit.

Carl Monroe; SPP ; #2 Anita Lee; AESO; #2	
Most commenters indicated a preference for 30 seconds, so this is what was used in the standard. The duration of the event would be measured as you've indicated, except that it would end at the point in time when the value reached the limit – there isn't a requirement to drop below the limit.	
Khaqan Khan; IMO; #2	While the 30 seconds duration may be too short, and 10 minutes be too long, a duration of 2 minutes may be more appropriate.
Most commenters indicated a preference for 30 seconds, so this is what was used in the standard.	
Kathleen Goodman; ISO-NE; #2	Should be reset immediately when the Limit is cleared and sustained. Should be cleared based on last good telemetry value.
Most commenters indicated a preference for 30 seconds, so this is what was used in the standard. The duration of the event would be measured as you've indicated.	
Alan Gale; City of Tallahassee; #5 Rusty Foster; City of Tallahassee; #3	Changes here may require looking at the sanctions table and the definition of Tv. Two minutes will ensure the IROL is truly mitigated and not the result of telemetry or integration errors. 5 or 10 minutes may result in exceeding Tv time limits when the IROL has been mitigated.
Most commenters indicated a preference for 30 seconds, so this is what was used in the standard.	
Michael Zahorik; ATC; #1	Time of an event is not important until the violation of over 30 minutes has occurred. An IRL should be addressed ASAP, the solution should also be ASAP, with penalties after the 30 minutes.
Most commenters indicated a preference for 30 seconds, so this is what was used in the standard. The penalties are for exceeding the IROL for time greater than Tv, and some IROLs are expected to have a T_v that is smaller than 30 minutes. WECC, for example has some IORLs that have a T_v of 20 minutes.	

16. Sanctions for exceeding an IROL for time greater than T_v

Several balloters requested that the sanction for exceeding an IROL for time greater than the IROL's Tv be modified so that the sanction is proportional to both the magnitude and the duration of the event. The SDT modified the sanction so that it would be the greater of the fixed dollar sanction listed in the matrix, or the dollar amount that corresponds to the magnitude and duration of the event as highlighted in the following table.

Do you agree with this table?

Summary Consideration: Most industry commenters are opposed to this sanctions table. Some of the commenters that opposed this table indicated that the last row of the table doesn't include a sanction for a maximum value greater than 30% and suggested the last stage should be set at equal to or greater than 25% and this change was implemented. Most of the commenters who oppose the table are opposed to all financial sanctions, and removing the sanctions is outside the scope of the SDT.

'Yes' Responses	
Gerald Rheault; Manitoba Hydro; #1,3,5,6	Manitoba Hydro agrees with the sanctions listed in the table below; however we believe the multiplications factors should continue to increase for event durations beyond 15 minutes. For example, the sanction for an event duration of one hour should be more severe than for an event duration of 15 minutes and so on.
Agreed. There were several commenters who made the same suggestion, and this has been adopted in the revised standard.	
John Horakh; MAAC; #2	The table can be simplified by making four columns for the four "event duration exceeds its Tv" segments, instead of repeating them six times. The table will then form a six by four grid with the multiplication factors filling the grid.
This will be a simplification and we will adopt your suggestion.	
Karl Kohlrus; City Water, Light & Power; # 5	
John Blazekovich; Exelon; 1,2,5,6	
William Pope; Gulf Power Co; #3	
Michael Zahorik; ATC; #1	
Peter Burke; ATC; #1	
William Smith; Allegheny Power; #1	
R. Peter Mackin; TRANC; #1	
Roman Carter; SCGEM; #5, 6 Joel Dison; SCGEM; #5, 6 Tony Reed; SCGEM; #5, 6 Lloyd Barnes; SCGEM; #5, 6 Clifford Shepard; SCGEM; #5, 6 Lucius Burris; SCGEM; #5, 6 Roger Green; SCGEM; #5, 6	
Marc Butts; Southern Company Svcs; #1	

Raymond Vice; Southern Company Svcs; #1 Dan Baisden; Southern Company Svcs; #1 Jim Griffith; Southern Company Svcs; #1 Phil Winston; Georgia Power Company; #3 Jim Viikinsalo; Southern Company Svcs; #1 Mike Miller; Southern Company Svcs; #1 Monroe Landrum; Southern Company Svcs; #1 Gwen Frazier; Southern Company Svcs; #1 Steve Williamson; Southern Company Svcs; #1 Rod Hardiman; Southern Company Svcs; #1 Jonathan Glidewell; Southern Company Svcs; 1 Dan Richards; Southern Company Svcs; #1 Mike Hardy; Southern Company Svcs; #1 David Majors; Georgia Power Company; #3	
Jalal Babik; Dominion VA Power; #1 Craig Crider; Dominion VA Power; #1 Jack Kerr; Dominion VA Power; #1 Bill Thompson; Dominion VA Power; #1	
Ed Riley; CA-ISO; #2	
Richard Kafka; Pepco; #3	
'No' Responses	
Ken Githens; Allegheny Energy; #5	Remove ≤ 30% from the last block.
Agreed. The table has been revised to reflect your suggestion.	
Raj Rana; AEP; 1,3,5,6	There are no sanctions listed for a Maximum Value over 30%. The last stage should be set at equal to or greater than 25%. The validity of the table is directly related to the definition of IROL. If an IROL is truly a significant interconnection event, similar in consequence to the August 14 event, then it doesn't matter if the IROL is violated for 30 minutes or 30 seconds, it was violated and it resulted in a blackout. If defined properly, a major portion of the interconnection would be jeopardized when an IROL is violated. If IROL were defined properly, the table would not be needed, as even exceeding the limit for a few minutes would be considered placing the interconnection at extreme risk and thus subject to maximum penalty. Therefore a graduated table may be inappropriate. On the other hand, if IROL is defined as only 300 MW of load loss, then a graduated table may be more fitting.
Agreed. The table has been revised to reflect your suggestion. The definition of an IROL has been revised. If an IROL would result in a cascading outage if left untended for 30 seconds, then the IROL should not have a Tv of 30 minutes – there should be some special protection system installed to prevent exceeding the IROL and the IROL should have a Tv that is	

<table>
<tr><td colspan="2">less than 30 seconds.

The table posted with the last version of the standard, reflects the industry's request for a sanctions table that develops a sanction based on the magnitude and duration of the instance of exceeding an IROL for time greater than the IROL's T_v.</td></tr>
<tr><td>Anita Lee; AESO; #2</td><td>Propose sanctions are too severe. Suggest using multiples of 2's rather than 5's. I.e. the first group will be 2, 4, 6, 8 and the next group be 4, 6, 8, 10 etc.</td></tr>
<tr><td colspan="2">Most commenters indicated that the sanctions were appropriate.</td></tr>
<tr><td>Dan Boezio; AEP; #1
Ron Ciesiel; SPP; #2
Bob Cochran; SPS; #1
Mike Gammon; KCP&L; #1
Allen Klassen; Westar; #1
Peter Kuebeck; OG&E; #1
Mike Stafford; GRDA; #1
Robert Rhodes; SPP; #2
Scott Moore; AEP; #1</td><td>There are no sanctions listed for a Maximum Value over 30%. The last stage should be set at equal to or greater than 25%.

The validity of the table is directly related to the definition of IROL. If an IROL is truly a significant interconnection event, similar in consequences to the August 14 event, then it doesn't matter if the IROL is violated for 5 minutes or 35 minutes, it was violated. If defined properly, a major portion of the interconnection would be jeopardized. If IROL were defined properly, the table would not be needed. Therefore a graduated table may be inappropriate. On the other hand, if IROL is defined as only 300 MW of load loss, then a graduated table may be more fitting.</td></tr>
<tr><td colspan="2">Agreed. The table has been revised to reflect your suggestion.

The definition of an IROL has been revised. If an IROL would result in a cascading outage if left untended for 30 seconds, then the IROL should not have a Tv of 30 minutes – there should be some special protection system installed to prevent exceeding the IROL and the IROL should have a Tv that is less than 30 seconds.

The table posted with the last version of the standard, reflects the industry's request for a sanctions table that develops a sanction based on the magnitude and duration of the instance of exceeding an IROL for time greater than the IROL's T_v.</td></tr>
<tr><td>Mark Fidrych; WAPA; #1</td><td>I agree with the concept, I think we need to spend some time on the multipliers.</td></tr>
<tr><td colspan="2">The SDT modified the table so the sanctions for exceeding an IROL by greater than 25 % are now included. The sanctions table is very closely aligned to one that is in existence in the WECC Region. Any suggestions for its improvement will be appreciated.</td></tr>
<tr><td>Ralph Rufrano; NYPA; #1
David Kiguel; Hydro One Networks Inc.; #1
Roger Champagne; H-Q TransÉnergie; #1
Greg Campoli; New York ISO (NYISO); #2
Peter Lebro; National Grid; #1
Kathleen Goodman; ISO-NE; #2
Dan Stosick; ISO-NE;#2
Al Adamson; NYSRC;#2
Khagan Khan; The IMO Ontario; #2
Brian Hogue; NPCC;#2
Guy Zito; NPCC;#2</td><td>We support Mr. Gent's comments to the NERC BOT that monetary sanctions are ineffective to ensure compliance and that market mechanisms and letters of increasing severity are more effective.

There is an issue with the concept of a monetary sanction matrix and what its implications are. NPCC, has expressed concern over its inclusion and maintains that the use of market mechanisms where possible, as well as, letters of increasing degrees of severity and notifications to regulatory agencies are more effective in ensuring compliance. Failure of NERC to gain authority through reliability legislation could result in NERC pursuing actions to implement</td></tr>
</table>

	"Plan B," a "voluntary" approach affording NERC the authority to perform these types of monetary sanctions. NPCC has indicated that any posted Standard, with such a matrix, will not be supported by NPCC, or its members. There are, however, proceedings at NERC by the Compliance Certification Committee (CCC) to address alternative sanction proposals and NPCC will continue to work to oppose monetary sanctions.
The SDT does not have the authority to modify the sanctions table.	
Kathleen Goodman; ISO-NE; #2	There is an issue with the concept of a monetary sanction matrix and what its implications are. ISO-NE, as well as NPCC, has expressed concern over its inclusion and maintains that the use of market mechanisms where possible, as well as, letters of increasing degrees of severity and notifications to regulatory agencies are more effective in ensuring compliance. Failure of NERC to gain authority through reliability legislation could result in NERC pursuing actions to implement "Plan B," a "voluntary" approach affording NERC the authority to perform these types of monetary sanctions. ISO-NE has indicated that any posted Standard, with such a matrix, will not be supported by ISO-NE. There are, however, proceedings at NERC by the Compliance Certification Committee (CCC) to address alternative sanction proposals and ISO-NE will continue to work to oppose monetary sanctions.
The SDT does not have the authority to modify the sanctions table.	
Greg Campoli; NYISO; #2 James Castle; NYISO ;#2 John Ravalli; NYISO; #2 Karl Tammar; NYISO; #2 Robert Waldele; NYISO; #2 Michael Calimano; NYISO; #	The NYISO agrees with the opinion, voiced by Mr. Gent's comments to the NERC BOT that monetary sanctions are ineffective to ensure compliance and that market mechanisms and letters of increasing severity are more effective. There is an issue with the concept of a monetary sanction matrix and what its implications are. NPCC, has expressed concern over its inclusion and maintains that the use of market mechanisms where possible, as well as, letters of increasing degrees of severity and notifications to regulatory agencies are more effective in ensuring compliance. Failure of NERC to gain authority through reliability legislation could result in NERC pursuing actions to implement "Plan B," a "voluntary" approach affording NERC the authority to perform these types of monetary sanctions. NPCC has indicated that any posted Standard, with such a matrix, will not be supported by NPCC, or its members.
The SDT does not have the authority to modify the sanctions table.	
Al Corbet; TVA Jerry Landers; TVA	"Duration" is ok, but magnitude (maximum value) should be taken out

Jennifer Weber; TVA Edd Forsythe; TVA Larry Goins; TVA Mark Creech; TVA Kathy Davis; TVA	
During the last posting of this standard, many commenters indicated that since IROLs have both a magnitude and a duration component, the sanction should be linked to the magnitude of exceeding both the magnitude and the duration of the IROL.	
Alan Gale; City of Tallahassee; #5 Rusty Foster; City of Tallahassee; #3	Although I agree with the need to increase the penalty to coincide with the magnitude of the violation, these proposed quantities could result in fines that would significantly impact utility operating budgets, customer rates, and even solvency. The starting point is not defined, but a $1,000 fine that could go to a $40,000 fine or a $4,000 fine going to a $160,000 is a big jump. The reason the IROL was exceeded needs to be addressed. Was it exceeded due to an "Act of God", an N-2 event, a willful violation of procedures, or the refusal to invest in necessary system repairs and upgrades? The difference should be addressed, possibly with a maximum fine.
Agreed. As shown on August 14, the impact of a cascading outage can be quite large. The intent of the sanctions is to motivate people to operate in a manner such that an IROL is not exceeded – and if there are circumstances that cause an IROL to be temporarily exceeded, then the RA should have plans in place to quickly mitigate the IROL before Tv is exceeded.	
Ed Davis; Entergy Services; #1	Entergy agrees with multipliers, but they should only be applied to repeat offenders. NERC should use multipliers if the same event occurs without remediation, or if different events pop up with the same systemic cause.
The multipliers are intended to reflect that allowing the RA's Area to be operated in a manner such that an IROL is exceeded by 20% of its value is more potentially impactive to the interconnection than operating in a manner such that an IROL is exceeded by 3% of its value.	
James Murphy; BPAT;#1 Mike Viles; BPAT; #1 Richard Spence; BPAT; #1 Don Watkins; BPAT; #1 Don Gold; BPAT; #1 Marv Landauer; BPAT; #1	We would agree with the table if the sanctions were applied to the appropriate entity. It seems unfair if the sanctions are applied to the RA if TOP did not follow the RA directive fast enough or not at all. One suggestion would require the RA to issue directive within 5 minutes. Below are some possible scenarios where IROL has been violated past Tv. These may be an over simplification, but it may be a good place to start. Scenario 1: RA issues directive in 5 minutes, the TOP does not follow directive fast enough or not at all, TOP gets sanction. Scenario 2: RA issues directive in 5 minutes, the TOP does follow directive fast enough, but directive did not solve problem, RA gets sanction. Scenario 3: RA issues directive past 5 minutes, RA gets sanctions.

	It has also been suggested in BPAT's group that a one time and one time only pass on the sanctions for the first ever offense, or some kind of phase in of the sanctions. This would be to recognize that there maybe some growing pains in implementing this standard for the first time.
There is nothing to preclude the RA from having a formal agreement with its TOPs that allows the RA to pass on any sanction associated with non-compliance of its TOPs. However, these new standards are set up so that the sanctions are assessed to those who are responsible for meeting the requirement – and in this case, the RA is responsible for ensuring that its RA Area is operated so that no IROLs are exceeded. There is another requirement in this standard that sanctions the TOP (or other entities) who do not comply with the RA's directives.	
John Swanson;NPDD;2 Darrick Moe;WAPA;2 Lloyd Linke;WAPA;2 Paul Koskela; MP; 2 Larry Larson; OTP; 2 Dick Pursley; GRE; 2 Martin Trence; XCEL; 2 Todd Gosnell; OPPD; 2 Robert Coish; MH; 2 Joe Knight; MAPPCOR; 2 Tom Mielnik; MEC; 2 Dave Jacobson; MH; 2 Delyn Helm; GRE; 2 Jason Weiers; OTP; 2 Dennis Kimm; MEC; 2	There should be no dollar amounts in the sanctions.
The SDT does not have the authority to remove financial sanctions from the sanctions table.	
Lawrence Hochberg; NYSRC; #2	The NYSRC is opposed to monetary sanctions as the only option for dealing with noncompliance as applied in this and other proposed NERC Standards. Unfortunately, direct monetary sanctions invite "gaming the system", and encourage "business" decisions based on potential profits or savings versus potential penalties. Instead of monetary sanctions, the NYSRC prefers that NERC have the authority to issue letters of increasing degrees of severity to communicate noncompliance of mandatory standards. The NYSRC and NPCC now rely on a more stringent and mandatory process than monetary sanctions to assure compliance with reliability standards. Compliance is now mandatory through the contractual agreements and tariffs that all participants need in order to conduct business. The use by the NYSRC and NPCC of letters to regulatory agencies and other oversight bodies for reporting noncompliance has demonstrated that letter sanctions are a more effective tool for ensuring adherence to standards. Such letters establish the

	basis for liability in the event of a subsequent criterion violation, and in the case of market participant noncompliance, threaten the violator's ability to do business with or through an ISO or RTO. Moreover, letters that communicate noncompliance best allow focus on the "root cause" of a violation, as well as its reliability impact. Therefore, the NYSRC recommends that this and other NERC Standards expressly provide that letter sanctions be used in addition to or instead of monetary sanctions under circumstances in which they would be an equally or more effective enforcement mechanism.
The SDT does not have the authority to remove financial sanctions from the sanctions table.	
Other Comments	
Khaqan Khan; IMO; #2	(Checked Yes and No)
Dale McMaster; AESO; #2 Ed Riley; CAISO; #2 Sam Jones; ERCOT; #2 Don Tench ; IMO; #2 Dave LaPlante; ISO_NE; #2 William Phillips; MISO; #2 Karl Tammar; NYISO; #2 Bruce Balmat; PJM; #2 Carl Monroe; SPP ; #2	The group did not reach consensus

Questions about Requirement 207 — Processes, Procedures or Plans for Preventing and Mitigating IROLs

17. Replace 'action plan' with 'process, procedure or plan'

Several balloters asked for more clarification on the term 'action plan' that was used in the last version of this standard. Several other drafting teams have used the terms, 'processes, procedures or plans' to clarify that the document required may be general in nature or very specific, as long as the document addresses the required topic. In response, the SDT changed the phrase, 'action plan' to 'processes, procedures or plans' throughout this requirement. Do you agree with this change?

Summary Consideration: All commenters but one were in favor of this addition.

Yes Responses	
Michael Zahorik; ATC; #1	We call them contingency plans
Yes, different entities have different names for these documents.	
Lee Xanthakos; SCE&G; #1	
Karl Kohlrus; City Water, Light & Power; # 5	
Raj Rana; AEP; 1,3,5,6	
John Blazekovich; Exelon; 1,2,5,6	
William Pope; Gulf Power Co; #3	
Gerald Rheault; Manitoba Hydro; #1,3,5,6	
James Murphy; BPAT;#1 Mike Viles; BPAT; #1 Richard Spence; BPAT; #1 Don Watkins; BPAT; #1 Don Gold; BPAT; #1 Marv Landauer; BPAT; #1	
William Smith; Allegheny Power; #1	
Peter Burke; ATC; #1	
Mark Fidrych; WAPA; #1	
Anita Lee; AESO; #2	
Dale McMaster; AESO; #2 Ed Riley; CAISO; #2 Sam Jones; ERCOT; #2 Don Tench ; IMO; #2 Dave LaPlante; ISO_NE; #2 William Phillips; MISO; #2 Karl Tammar; NYISO; #2 Bruce Balmat; PJM; #2 Carl Monroe; SPP ; #2	
Patti Metro; FRCC; #2 Linda Campbell ;FRCC ;#2	

Steve Wallace; Seminole Electric Coop ;#4 Amy Long; Lakeland Electric; #1 Richard Gilbert; Lakeland Electric; #3 Ron Donahey; Tampa Electric Company; #3 Beth Young; Tampa Electric Company ;#3 Roger Hunnicutt ; Gainesville Reg Utl; #5 Roger Westphal ;City of Gainesville; #3 Greg Woessner ;Kissimmee Utility Auth;#3 Ben Sharma ;Kissimmee Utility Auth;#3 Garry Baker; JEA ;#1 Ed DeVarona; Florida Power & Light Co. ;#1 Preston Pierce; Progress Energy Florida ;#1 Bob Remley; Clay Electric Cooperative; #4 Joe Krupar; FMPA; #3 Paul Elwing; Lakeland Electric; #5 Joe Roos; Ocala Electric Utility ;#3	
Greg Campoli; NYISO; #2 James Castle; NYISO ;#2 John Ravalli; NYISO; #2 Karl Tammar; NYISO; #2 Robert Waldele; NYISO; #2 Michael Calimano; NYISO; #	
Ralph Rufrano; NYPA; #1 David Kiguel; Hydro One Networks Inc.; #1 Roger Champagne; H-Q TransÉnergie; #1 Greg Campoli; New York ISO (NYISO); #2 Peter Lebro; National Grid; #1 Kathleen Goodman; ISO-NE; #2 Dan Stosick; ISO-NE;#2 Al Adamson; NYSRC;#2 Khagan Khan; The IMO Ontario; #2 Brian Hogue; NPCC;#2 Guy Zito; NPCC;#2	
Al Corbet; TVA Jerry Landers; TVA Jennifer Weber; TVA Edd Forsythe; TVA Larry Goins; TVA Mark Creech; TVA Kathy Davis; TVA	
Carter Edge; SEPA ; #4 & 5	

William Gaither; SC Public Svc Auth; #1 Ken Skroback; AL Elec Coop ; #1 Roger Brand; Muni Elec Auth of GA; #1 Phil Creech; Progress Energy - Carolinas; #1 Gene Delk; SCE&G; #1 Al McMeekin; SCE&G; #1 Randy Hunt; Dominion – VA Pwr; #1 Doug Newbauer; GA System Ops; #1 Mike Clements; TVA; #1 Don Reichenbach; Duke Energy; #1 Lynna Estep; SERC; #2 Dan Kay; S Mississippi Elec Pwr Assoc; #1 Matt Ansley; Southern Company; #1 Uma Gangadharan; Entergy; #1	
R. Peter Mackin; TRANC; #1	
Roman Carter; SCGEM; #5, 6 Joel Dison; SCGEM; #5, 6 Tony Reed; SCGEM; #5, 6 Lloyd Barnes; SCGEM; #5, 6 Clifford Shepard; SCGEM; #5, 6 Lucius Burris; SCGEM; #5, 6 Roger Green; SCGEM; #5, 6	
Marc Butts; Southern Company Svcs; #1 Raymond Vice; Southern Company Svcs; #1 Dan Baisden; Southern Company Svcs; #1 Jim Griffith; Southern Company Svcs; #1 Phil Winston; Georgia Power Company; #3 Jim Viikinsalo; Southern Company Svcs; #1 Mike Miller; Southern Company Svcs; #1 Monroe Landrum; Southern Company Svcs; #1 Gwen Frazier; Southern Company Svcs; #1 Steve Williamson; Southern Company Svcs; #1 Rod Hardiman; Southern Company Svcs; #1 Jonathan Glidewell; Southern Company Svcs; 1 Dan Richards; Southern Company Svcs; #1 Mike Hardy; Southern Company Svcs; #1 David Majors; Georgia Power Company; #3	
Khaqan Khan; IMO; #2	
Jalal Babik; Dominion VA Power; #1 Craig Crider; Dominion VA Power; #1 Jack Kerr; Dominion VA Power; #1	

Bill Thompson; Dominion VA Power; #1	
Lawrence Hochberg; NYSRC; #2	
John Swanson;NPDD;2 Darrick Moe;WAPA;2 Lloyd Linke;WAPA;2 Paul Koskela; MP; 2 Larry Larson; OTP; 2 Dick Pursley; GRE; 2 Martin Trence; XCEL; 2 Todd Gosnell; OPPD; 2 Robert Coish; MH; 2 Joe Knight; MAPPCOR; 2 Tom Mielnik; MEC; 2 Dave Jacobson; MH; 2 Delyn Helm; GRE; 2 Jason Weiers; OTP; 2 Dennis Kimm; MEC; 2	
Alan Gale; City of Tallahassee; #5 Rusty Foster; City of Tallahassee; #3	
Richard Kafka; Pepco; #3	
Dan Boezio; AEP; #1 Ron Ciesiel; SPP; #2 Bob Cochran; SPS; #1 Mike Gammon; KCP&L; #1 Allen Klassen; Westar; #1 Peter Kuebeck; OG&E; #1 Mike Stafford; GRDA; #1 Robert Rhodes; SPP; #2 Scott Moore; AEP; #1	
John Horakh; MAAC; #2	
Ken Githens; Allegheny Energy; #5	
Ed Davis; Entergy Services; #1	
Ed Riley; CA-ISO; #2	
Other Responses	
Kathleen Goodman; ISO-NE; #2	Do not believe there should be a requirement for either. Operators should be appropriately trained and provided with strategies to take the correct actions necessary to operate a system reliably. (Checked both Yes and No)
One of the best training tools is a well-planned document that outlines appropriate actions for various scenarios. Agreed that system operators should be trained and provided with strategies – and this standard requires that the strategies be documented as processes, procedures or plans.	

Other Questions about this Standard

18. Are you a member of the Ballot Pool (or do you represent a member of the Ballot Pool) for this standard?

Summary Consideration:
The SDT asked questions 18-20 to determine if there was a reason to ballot this standard before issues related to the standards development process, but outside the scope of the SDT, were addressed. When this standard was balloted the first time, most of the reasons for not approving the standard were related to either the Functional Model, Field Testing or Financial Sanctions. The SDT cannot make changes to any of these items. The SDT does not want to ballot the standard and have it fail because of these issues which are outside the technical content of the standard. Many of the balloters who voted against the standard, have declined to answer these questions, so the SDT does not know if these balloters have changed their mind and will vote on the standard based on technical content rather than on an understanding of the Functional Model, Financial Sanctions, or Field Testing.

Yes Responses	
Some of the following: Carter Edge; SEPA ; #4 & 5 William Gaither; SC Public Svc Auth; #1 Ken Skroback; AL Elec Coop ; #1 Roger Brand; Muni Elec Auth of GA; #1 Phil Creech; Progress Energy - Carolinas; #1 Gene Delk; SCE&G; #1 Al McMeekin; SCE&G; #1 Randy Hunt; Dominion – VA Pwr; #1 Doug Newbauer; GA System Ops; #1 Mike Clements; TVA; #1 Don Reichenbach; Duke Energy; #1 Lynna Estep; SERC; #2 Dan Kay; S Mississippi Elec Pwr Assoc; #1 Matt Ansley; Southern Company; #1 Uma Gangadharan; Entergy; #1	We are a group and some members represent members of the Ballot Pool.
Lee Xanthakos; SCE&G; #1	
Karl Kohlrus; City Water, Light & Power; # 5	
Raj Rana; AEP; 1,3,5,6	
John Blazekovich; Exelon; 1,2,5,6	
Gerald Rheault; Manitoba Hydro; #1,3,5,6	
William Pope; Gulf Power Co; #3	
James Murphy; BPAT;#1 Mike Viles; BPAT; #1 Richard Spence; BPAT; #1 Don Watkins; BPAT; #1	

Don Gold; BPAT; #1 Marv Landauer; BPAT; #1	
Patti Metro; FRCC; #2 Linda Campbell ;FRCC ;#2 Steve Wallace; Seminole Electric Coop ;#4 Amy Long; Lakeland Electric; #1 Richard Gilbert; Lakeland Electric; #3 Ron Donahey; Tampa Electric Company; #3 Beth Young; Tampa Electric Company ;#3 Roger Hunnicutt ; Gainesville Reg Utl; #5 Roger Westphal ;City of Gainesville; #3 Greg Woessner ;Kissimmee Utility Auth;#3 Ben Sharma ;Kissimmee Utility Auth;#3 Garry Baker; JEA ;#1 Ed DeVarona; Florida Power & Light Co. ;#1 Preston Pierce; Progress Energy Florida ;#1 Bob Remley; Clay Electric Cooperative; #4 Joe Krupar; FMPA; #3 Paul Elwing; Lakeland Electric; #5 Joe Roos; Ocala Electric Utility ;#3	
William Smith; Allegheny Power; #1	
Peter Burke; ATC; #1	
Mark Fidrych; WAPA; #1	
Anita Lee; AESO; #2	
Greg Campoli; NYISO; #2 James Castle; NYISO ;#2 John Ravalli; NYISO; #2 Karl Tammar; NYISO; #2 Robert Waldele; NYISO; #2 Michael Calimano; NYISO; #	
Chifong Thomas; PG&E; #1 Glenn Rounds; PG&E; #1 Ben Morris; PG&E; #1	
Ralph Rufrano; NYPA; #1 David Kiguel; Hydro One Networks Inc.; #1 Roger Champagne; H-Q TransÉnergie; #1 Greg Campoli; New York ISO (NYISO); #2 Peter Lebro; National Grid; #1 Kathleen Goodman; ISO-NE; #2	

Dan Stosick; ISO-NE;#2 Al Adamson; NYSRC;#2 Khagan Khan; The IMO Ontario; #2 Brian Hogue; NPCC;#2 Guy Zito; NPCC;#2	
Al Corbet; TVA Jerry Landers; TVA Jennifer Weber; TVA Edd Forsythe; TVA Larry Goins; TVA Mark Creech; TVA Kathy Davis; TVA	
Khaqan Khan; IMO; #2	
Kathleen Goodman; ISO-NE; #2	
R. Peter Mackin; TRANC; #1	
Roman Carter; SCGEM; #5, 6 Joel Dison; SCGEM; #5, 6 Tony Reed; SCGEM; #5, 6 Lloyd Barnes; SCGEM; #5, 6 Clifford Shepard; SCGEM; #5, 6 Lucius Burris; SCGEM; #5, 6 Roger Green; SCGEM; #5, 6	
Marc Butts; Southern Company Svcs; #1 Raymond Vice; Southern Company Svcs; #1 Dan Baisden; Southern Company Svcs; #1 Jim Griffith; Southern Company Svcs; #1 Phil Winston; Georgia Power Company; #3 Jim Viikinsalo; Southern Company Svcs; #1 Mike Miller; Southern Company Svcs; #1 Monroe Landrum; Southern Company Svcs; #1 Gwen Frazier; Southern Company Svcs; #1 Steve Williamson; Southern Company Svcs; #1 Rod Hardiman; Southern Company Svcs; #1 Jonathan Glidewell; Southern Company Svcs; 1 Dan Richards; Southern Company Svcs; #1 Mike Hardy; Southern Company Svcs; #1 David Majors; Georgia Power Company; #3	
Lawrence Hochberg; NYSRC; #2	
Jalal Babik; Dominion VA Power; #1 Craig Crider; Dominion VA Power; #1 Jack Kerr; Dominion VA Power; #1	

Bill Thompson; Dominion VA Power; #1	
Alan Gale; City of Tallahassee; #5 Rusty Foster; City of Tallahassee; #3	
Ed Davis; Entergy Services; #1	
Ken Githens; Allegheny Energy; #5	
Ed Riley; CA-ISO; #2	
Some of the following Dan Boezio; AEP; #1 Ron Ciesiel; SPP; #2 Bob Cochran; SPS; #1 Mike Gammon; KCP&L; #1 Allen Klassen; Westar; #1 Peter Kuebeck; OG&E; #1 Mike Stafford; GRDA; #1 Robert Rhodes; SPP; #2 Scott Moore; AEP; #1	
Richard Kafka; Pepco; #3	
Some of the following: John Swanson;NPDD;2 Darrick Moe;WAPA;2 Lloyd Linke;WAPA;2 Paul Koskela; MP; 2 Larry Larson; OTP; 2 Dick Pursley; GRE; 2 Martin Trence; XCEL; 2 Todd Gosnell; OPPD; 2 Robert Coish; MH; 2 Joe Knight; MAPPCOR; 2 Tom Mielnik; MEC; 2 Dave Jacobson; MH; 2 Delyn Helm; GRE; 2 Jason Weiers; OTP; 2 Dennis Kimm; MEC; 2	
'No' Responses	
Some of the following Dan Boezio; AEP; #1 Ron Ciesiel; SPP; #2 Bob Cochran; SPS; #1 Mike Gammon; KCP&L; #1 Allen Klassen; Westar; #1 Peter Kuebeck; OG&E; #1	

Mike Stafford; GRDA; #1 Robert Rhodes; SPP; #2 Scott Moore; AEP; #1	
John Horakh; MAAC; #2	
Some of the following: John Swanson;NPDD;2 Darrick Moe;WAPA;2 Lloyd Linke;WAPA;2 Paul Koskela; MP; 2 Larry Larson; OTP; 2 Dick Pursley; GRE; 2 Martin Trence; XCEL; 2 Todd Gosnell; OPPD; 2 Robert Coish; MH; 2 Joe Knight; MAPPCOR; 2 Tom Mielnik; MEC; 2 Dave Jacobson; MH; 2 Delyn Helm; GRE; 2 Jason Weiers; OTP; 2 Dennis Kimm; MEC; 2	
Michael Zahorik; ATC; #1	
Other Responses	
Dale McMaster; AESO; #2 Ed Riley; CAISO; #2 Sam Jones; ERCOT; #2 Don Tench ; IMO; #2 Dave LaPlante; ISO_NE; #2 William Phillips; MISO; #2 Karl Tammar; NYISO; #2 Bruce Balmat; PJM; #2 Carl Monroe; SPP ; #2	We are all members of the ballot pool and intend to vote individually. There was no discussion of the remaining questions as a group response seemed inappropriate.
The SDT asked questions 18-20 to determine if there was a reason to ballot this standard before issues related to the standards development process, but outside the scope of the SDT, were addressed. When this standard was balloted the first time, most of the reasons for not approving the standard were related to either the Functional Model, Field Testing or Financial Sanctions. The SDT cannot make changes to any of these items. The SDT does not want to ballot the standard and have it fail because of these issues which are outside the technical content of the standard.	

19. Do you agree with the Technical Content

If you are a member of the Ballot Pool (or if you represent a member of the Ballot Pool), do you agree with the technical content of this standard? Note that the technical content of the standard consists solely of the individual Requirements and their associated Measures — the Compliance Monitoring Process, Levels of Non-compliance and Sanctions are not considered part of the 'technical content' of the standard.

Member & agree with Technical Content	
Some of the following Dan Boezio; AEP; #1 Ron Ciesiel; SPP; #2 Bob Cochran; SPS; #1 Mike Gammon; KCP&L; #1 Allen Klassen; Westar; #1 Peter Kuebeck; OG&E; #1 Mike Stafford; GRDA; #1 Robert Rhodes; SPP; #2 Scott Moore; AEP; #1	Depending upon the response to our comments and what revisions are made, we can agree or disagree with the technical content of this standard.
Alan Gale; City of Tallahassee; #5 Rusty Foster; City of Tallahassee; #3	I agree with the technical content as amended by my comments. I will reserve judgment until I see how they are incorporated.
Lee Xanthakos; SCE&G; #1	I'm not sure that the Requirements of this standard represent technical content, but since I pretty much agree with the requirements so I checked box 1.
Karl Kohlrus; City Water, Light & Power; # 5	
William Pope; Gulf Power Co; #3	
James Murphy; BPAT;#1 Mike Viles; BPAT; #1 Richard Spence; BPAT; #1 Don Watkins; BPAT; #1 Don Gold; BPAT; #1 Marv Landauer; BPAT; #1	
Anita Lee; AESO; #2	
Mark Fidrych; WAPA; #1	
Some of the following: Greg Campoli; NYISO; #2 James Castle; NYISO ;#2 John Ravalli; NYISO; #2 Karl Tammar; NYISO; #2 Robert Waldele; NYISO; #2 Michael Calimano; NYISO; #2	
Chifong Thomas; PG&E; #1	

Glenn Rounds; PG&E; #1 Ben Morris; PG&E; #1	
Roman Carter; SCGEM; #5, 6 Joel Dison; SCGEM; #5, 6 Tony Reed; SCGEM; #5, 6 Lloyd Barnes; SCGEM; #5, 6 Clifford Shepard; SCGEM; #5, 6 Lucius Burris; SCGEM; #5, 6 Roger Green; SCGEM; #5, 6	
R. Peter Mackin; TRANC; #1	
Ed Riley; CA-ISO; #2	
Marc Butts; Southern Company Svcs; #1 Raymond Vice; Southern Company Svcs; #1 Dan Baisden; Southern Company Svcs; #1 Jim Griffith; Southern Company Svcs; #1 Phil Winston; Georgia Power Company; #3 Jim Viikinsalo; Southern Company Svcs; #1 Mike Miller; Southern Company Svcs; #1 Monroe Landrum; Southern Company Svcs; #1 Gwen Frazier; Southern Company Svcs; #1 Steve Williamson; Southern Company Svcs; #1 Rod Hardiman; Southern Company Svcs; #1 Jonathan Glidewell; Southern Company Svcs; 1 Dan Richards; Southern Company Svcs; #1 Mike Hardy; Southern Company Svcs; #1 David Majors; Georgia Power Company; #3	
Richard Kafka; Pepco; #3	
Member & do not agree with Technical Content	
Some of the following: Greg Campoli; NYISO; #2 James Castle; NYISO ;#2 John Ravalli; NYISO; #2 Karl Tammar; NYISO; #2 Robert Waldele; NYISO; #2 Michael Calimano; NYISO; #	As indicated in our responses, the NYISO agrees with much of the technical content of this standard and offers suggestions and opinions on the portions we disagree with.
Peter Burke; ATC; #1	ATC agrees with some of the technical content of this standard but is concerned that this question requires us to agree to all of the technical content of this standard and if we do not, we should check “I do not agree”. The SDT is on the correct path in achieving approval of this standard but this latest version presents some problems / concerns.

Jalal Babik; Dominion VA Power; #1 Craig Crider; Dominion VA Power; #1 Jack Kerr; Dominion VA Power; #1 Bill Thompson; Dominion VA Power; #1	See comments under items 1, 2, 4, 5, 9, and 11.
Gerald Rheault; Manitoba Hydro; #1,3,5,6	Manitoba Hydro has technical concerns relative to the concept of IROL as referenced in this Standard. These concerns have been provided to the SDT in previous postings of this Standard and are further elaborated upon in question 12 of this comment document. If the SDT can satisfactorily address these concerns, then Manitoba Hydro would support this Standard.
The SDT has tried to address your technical concerns.	
Kathleen Goodman; ISO-NE; #2	Example: 208 requires documentation of the RA'a directives and the actions taken. Also, although the levels of non-compliance are not considered as "technical content," for the purpose of explaining the disagreement, we need to reference Level 1 non-compliance, which is directly related to the requirement. If the actions were taken and the directives were followed, why would an operator be found non-compliant for not documenting such actions and directives?
If the actions aren't documented, how will anyone know if the directives were followed? The documentation required, is simply the same documentation that is typically captured in most control room operating logs. The language in the standard allows the RA to choose any method of documentation – the intent isn't to require new systems be installed or implemented – the intent is to ensure that all involved recognize the seriousness of operating within IROLs – and there needs to be a method of ensuring that the work practices that support this behavior can be assessed.	
Ken Githens; Allegheny Energy; #5	
William Smith; Allegheny Power; #1	
Ed Davis; Entergy Services; #1	
Lawrence Hochberg; NYSRC; #2	
Ralph Rufrano; NYPA; #1 David Kiguel; Hydro One Networks Inc.; #1 Roger Champagne; H-Q TransÉnergie; #1 Greg Campoli; New York ISO (NYISO); #2 Peter Lebro; National Grid; #1 Kathleen Goodman; ISO-NE; #2 Dan Stosick; ISO-NE;#2 Al Adamson; NYSRC;#2 Khagan Khan; The IMO Ontario; #2 Brian Hogue; NPCC;#2 Guy Zito; NPCC;#2	

Raj Rana; AEP; 1,3,5,6	
Not a member & agree with Technical Content	
John Horakh; MAAC; #2	
Not a member & do not agree with Technical Content	
Carter Edge; SEPA ; #4 & 5 William Gaither; SC Public Svc Auth; #1 Ken Skroback; AL Elec Coop ; #1 Roger Brand; Muni Elec Auth of GA; #1 Phil Creech; Progress Energy - Carolinas; #1 Gene Delk; SCE&G; #1 Al McMeekin; SCE&G; #1 Randy Hunt; Dominion – VA Pwr; #1 Doug Newbauer; GA System Ops; #1 Mike Clements; TVA; #1 Don Reichenbach; Duke Energy; #1 Lynna Estep; SERC; #2 Dan Kay; S Mississippi Elec Pwr Assoc; #1 Matt Ansley; Southern Company; #1 Uma Gangadharan; Entergy; #1	We are a group and some members represent members of the Ballot Pool.
Other Comments	
John Blazekovich; Exelon; 1,2,5,6	Before we determine how Exelon will cast it's votes we would like to see revision to the definitions (as commented) and some direction on how compliance with this Standard will be accomplished on a "real time" basis.
Khaqan Khan; IMO; #2	Checked both agree and disagree with technical content– member of Ballot Pool -

20. Vote based on technical content

If you are a member of the Ballot Pool (or if you represent a member of the Ballot Pool), will you vote on this standard based on its content (requirements, measures, compliance monitoring process and levels of non-compliance), or will you withhold your approval based on factors related to the standards process? This would include factors such as changes to the Functional Model, the removal of Financial Sanctions from the Compliance Enforcement Program, or the inclusion of Field Testing.

Member & will vote based on Content	
Peter Burke; ATC; #1	ATCs approach is to review each standard on its own merits
James Murphy; BPAT;#1 Mike Viles; BPAT; #1 Richard Spence; BPAT; #1 Don Watkins; BPAT; #1 Don Gold; BPAT; #1 Marv Landauer; BPAT; #1	BPAT may or may not vote against this standard based on changes to the Functional Model and based on the structure of the Financial Sanctions. BPAT has not determined this yet.
Karl Kohlrus; City Water, Light & Power; # 5	
William Pope; Gulf Power Co; #3	
John Blazekovich; Exelon; 1,2,5,6	
Raj Rana; AEP; 1,3,5,6	
Gerald Rheault; Manitoba Hydro; #1,3,5,6	
Anita Lee; AESO; #2	
Mark Fidrych; WAPA; #1	
Chifong Thomas; PG&E; #1 Glenn Rounds; PG&E; #1 Ben Morris; PG&E; #1	
Kathleen Goodman; ISO-NE; #2	
William Smith; Allegheny Power; #1	
R. Peter Mackin; TRANC; #1	
Greg Campoli; NYISO; #2 James Castle; NYISO ;#2 John Ravalli; NYISO; #2 Karl Tammar; NYISO; #2 Robert Waldele; NYISO; #2 Michael Calimano; NYISO; #2	
Some of the following: Ralph Rufrano; NYPA; #1 David Kiguel; Hydro One Networks Inc.; #1 Roger Champagne; H-Q TransÉnergie; #1 Greg Campoli; New York ISO (NYISO); #2 Peter Lebro; National Grid; #1	

Kathleen Goodman; ISO-NE; #2 Dan Stosick; ISO-NE;#2 Al Adamson; NYSRC;#2 Khagan Khan; The IMO Ontario; #2 Brian Hogue; NPCC;#2 Guy Zito; NPCC;#2	
Roman Carter; SCGEM; #5, 6 Joel Dison; SCGEM; #5, 6 Tony Reed; SCGEM; #5, 6 Lloyd Barnes; SCGEM; #5, 6 Clifford Shepard; SCGEM; #5, 6 Lucius Burris; SCGEM; #5, 6 Roger Green; SCGEM; #5, 6	
Marc Butts; Southern Company Svcs; #1 Raymond Vice; Southern Company Svcs; #1 Dan Baisden; Southern Company Svcs; #1 Jim Griffith; Southern Company Svcs; #1 Phil Winston; Georgia Power Company; #3 Jim Viikinsalo; Southern Company Svcs; #1 Mike Miller; Southern Company Svcs; #1 Monroe Landrum; Southern Company Svcs; #1 Gwen Frazier; Southern Company Svcs; #1 Steve Williamson; Southern Company Svcs; #1 Rod Hardiman; Southern Company Svcs; #1 Jonathan Glidewell; Southern Company Svcs; 1 Dan Richards; Southern Company Svcs; #1 Mike Hardy; Southern Company Svcs; #1 David Majors; Georgia Power Company; #3	
Khaqan Khan; IMO; #2	
Ed Riley; CA-ISO; #2	
Richard Kafka; Pepco; #3	
Ken Githens; Allegheny Energy; #5	
Ed Davis; Entergy Services; #1	
Alan Gale; City of Tallahassee; #5 Rusty Foster; City of Tallahassee; #3	
Lawrence Hochberg; NYSRC; #2	
Some of the following Dan Boezio; AEP; #1 Ron Ciesiel; SPP; #2 Bob Cochran; SPS; #1 Mike Gammon; KCP&L; #1	

Allen Klassen; Westar; #1 Peter Kuebeck; OG&E; #1 Mike Stafford; GRDA; #1 Robert Rhodes; SPP; #2 Scott Moore; AEP; #1	
Member & will vote against standard based on other issues	
James Murphy; BPAT;#1 Mike Viles; BPAT; #1 Richard Spence; BPAT; #1 Don Watkins; BPAT; #1 Don Gold; BPAT; #1 Marv Landauer; BPAT; #1	BPAT may or may not vote against this standard based on changes to the Functional Model and based on the structure of the Financial Sanctions. BPAT has not determined this yet.
Jalal Babik; Dominion VA Power; #1 Craig Crider; Dominion VA Power; #1 Jack Kerr; Dominion VA Power; #1 Bill Thompson; Dominion VA Power; #1	
Al Corbet; TVA Jerry Landers; TVA Jennifer Weber; TVA Edd Forsythe; TVA Larry Goins; TVA Mark Creech; TVA Kathy Davis; TVA	
Some of the following: Ralph Rufrano; NYPA; #1 David Kiguel; Hydro One Networks Inc.; #1 Roger Champagne; H-Q TransÉnergie; #1 Greg Campoli; New York ISO (NYISO); #2 Peter Lebro; National Grid; #1 Kathleen Goodman; ISO-NE; #2 Dan Stosick; ISO-NE;#2 Al Adamson; NYSRC;#2 Khagan Khan; The IMO Ontario; #2 Brian Hogue; NPCC;#2 Guy Zito; NPCC;#2	
Not Applicable – not a member of BP	
John Horakh; MAAC; #2	

21. Other Comments about this Standard

<table>
<tr><td>John Swanson;NPDD;2
Darrick Moe;WAPA;2
Lloyd Linke;WAPA;2
Paul Koskela; MP; 2
Larry Larson; OTP; 2
Dick Pursley; GRE; 2
Martin Trence; XCEL; 2
Todd Gosnell; OPPD; 2
Robert Coish; MH; 2
Joe Knight; MAPPCOR; 2
Tom Mielnik; MEC; 2
Dave Jacobson; MH; 2
Delyn Helm; GRE; 2
Jason Weiers; OTP; 2
Dennis Kimm; MEC; 2</td><td>We support the prerequisite approval provided on page 2 for the implementation plan of this Standard 200 in which Standard 600 Determine Facility Ratings, System Operating Limits and Transfer Capabilities Standard must be implemented before this standard can be implemented. However, we believe that another prerequisite approval is that the NERC SAC verify that this Standard 200 does not conflict with Standard 600. Otherwise, there will be problems in implementing the two standards. If the SAC determines there is a conflict, then the SAC should send one or both standards back to the drafting teams to be resolved.

The dollar sanctions should be removed from all sections of this standard. The sanctions sections should be replaced with:

(1) Sanctions for noncompliance shall be applied consistent with the NERC compliance and enforcement matrix, but no financial penalties shall be enforced. Noncompliance sanctions shall consist of letters, issued in accordance with the matrix.</td></tr>
<tr><td colspan="2">The SAC does not get involved in a technical review of the standards. The SAC's function is to ensure that the standards process is being followed. It is up to the industry to comment on any disconnects between standards.

The SDT does not have the authority to remove financial sanctions. The SDT has informed the SAC that there are many industry participants who are opposed to financial sanctions, and has asked the SAC to address this issue before this standard is balloted.</td></tr>
<tr><td>Marc Butts; Southern Company Svcs; #1
Raymond Vice; Southern Company Svcs; #1
Dan Baisden; Southern Company Svcs; #1
Jim Griffith; Southern Company Svcs; #1
Phil Winston; Georgia Power Company; #3
Jim Viikinsalo; Southern Company Svcs; #1
Mike Miller; Southern Company Svcs; #1
Monroe Landrum; Southern Company Svcs; #1
Gwen Frazier; Southern Company Svcs; #1
Steve Williamson; Southern Company Svcs; #1
Rod Hardiman; Southern Company Svcs; #1
Jonathan Glidewell; Southern Company Svcs; 1
Dan Richards; Southern Company Svcs; #1
Mike Hardy; Southern Company Svcs; #1
David Majors; Georgia Power Company; #3</td><td>We would like to express our appreciation to the SDT for taking the time and trouble to revisit the comments on this standard. We realize the time it takes to participate on these teams and the dedication to it. While the last version of this standard was voted down this version is greatly improved and should pass the test. Thank you all for your efforts to listen to the industry and the people who operate the power systems on a daily basis and making this a workable product. We applaud you.</td></tr>
</table>

<table>
<tr><td>Roman Carter; SCGEM; #5, 6
Joel Dison; SCGEM; #5, 6
Tony Reed; SCGEM; #5, 6
Lloyd Barnes; SCGEM; #5, 6
Clifford Shepard; SCGEM; #5, 6
Lucius Burris; SCGEM; #5, 6
Roger Green; SCGEM; #5, 6</td><td></td></tr>
<tr><td colspan="2">The SDT very much appreciates your support.</td></tr>
<tr><td>Khaqan Khan; IMO; #2</td><td>1. The footnote on Std 201 states that each IROL is developed by following the requirements in “Determine Facility Ratings, SOL’s & Transfer Capabilities” i.e. Std 600. Such requirements with respect to IROL are not mentioned in existing standard Std 600, and it is expected that upcoming revised standard shall include this requirement otherwise it is recommended to delete the keynote from this standard 200.

2. The IMO supports the comments submitted by ISO/RTO Council- Standards Review Committee as well as the CP-9 Group.</td></tr>
<tr><td colspan="2">The footnote on Requirement 201 was placed at the request of many industry commenters who wanted a specific reference to Standard 600 included in this standard. Since the requirement to identify IROLs was transferred to the Determine Facility Ratings Standard, the footnote is not in the revised standard.
Please see the SDT’s consideration of the ISO/RTO Council Standards Review Committee and the SDT’s consideration of the comments submitted by the NPCC CP-9 Group.</td></tr>
<tr><td>Peter Burke; ATC; #1</td><td>202 Monitoring
1. The SDT switches between the terms “operations personnel” and “system operators.” It seems that both of these terms refer to the same people. If so, could the SDT choose a single term to refer to that group? If not, could the SDT explain the difference?
2. Noncompliance
(4) i. This seems to be identical to (ii). Could the SDT clarify the difference?
(4) iii. How would this be reviewed? It seems that this is a subjective item, would the SDT please clarify?
203 Analyses and Assessment
3. This goes back to our earlier comments about the definition of a Real-Time Assessment. It seems what the SDT is attempting to do is perform two different studies in this one requirement.
Compliance Monitoring Process
(3) ii. The Operational Planning Analysis is a study of the next day using forecasted data, transmission outage data, and generation outage data and can</td></tr>
</table>

	only attempt to see what may happen the next day. Given that statement, how can the RA be assured that it will exceed an IROL? Suggestion: change the "will exceed" to "may exceed." (3) iv. Remove the statement "or is expected to exceed any IROLs." The Real-Time assessment should be limited to real-time time frame and should be extended to review the time between Real-Time Assessments. Non Compliance (3) i. Is the "time" that an Operational Planning Analysis or Real-Time Assessment was conducted sufficient enough indication that Operational Planning Analysis or Real-Time Assessment was conducted? 204 Actions (1) i. ATC is troubled by the term may be exceeded. How can an RA be required to perform action on a "may" situation? Suggestion would be to have the RA notify other RA along with members in the RA's area that an IROL was not yet exceeded but the potential for an IROL to be exceeded was identified. We would point out that there is no noncompliance level for the above concern so therefore should this may not be appropriate as a NERC standard.

202 Monitoring

1. The term, 'Operations Personnel' was originally intended to include a group of people who work in the area of system operations, but was not intended to be limited to system operators. System Operators are the on-shift personnel assigned to monitor and control the system. Other commenters also requested clarification of the use of these terms. The standard has been changed to use just the term, 'system operators.'

4 (i) indicates that the system operators don't have information to let them know what their IROLs are – 4(ii) indicates that the system operators don't have the ability to look at real-time data and compare it to IROLs.

The data has to be accessible in real-time and that availability can be observed by the Compliance Monitor.

203 Analyses and Assessment

3.ii - The system operator is expected to notice if real-time assessments conducted every 30 minutes show that limits are being approached. The system operator is expected to interpret the real-time assessments in context of the day's operations, and is expected to notice changes over time so actions can be taken to prevent exceeding any IROL. The standard doesn't specify specific real-time assessment methodology – each RA has a unique system, and may be looking for different specifics based on its current conditions.

3.iv – The real-time assessment isn't done in isolation, it is part of an overall process of conducing real-time assessments every 30 minutes. The results of these assessments should indicate to the RA when emerging conditions are such that an IROL is being approached – and the RA is expect to act before the IROL is exceeded. The existing language accurately represents what was intended by this requirement.

Noncompliance level 3i - The Compliance Monitoring process provides a list of questions that the Compliance Monitor will use to determine if the system operator has been interpreting the results of the analyses and assessments with respect to IROLs. The responses to those questions will show the Compliance Monitor whether an analysis or an assessment was conducted. If the system operator

<table>
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conducted an assessment but doesn't remember what it showed, then that was not effective enough to meet this requirement.
This has to be assessed in context of the summary of all the questions that are asked of the real-time system operator. This is not a one-for-one alignment between the first question and an associated level of non-compliance. This has been modified to clarify what was intended.
204 Actions
1i - The SDT thinks 'may' is the right word – one of the focuses of this standard is to try and identify situations that may lead to exceeding an IROL and to take action to prevent exceeding that IROL. The industry commenters have supported this position.
If the RA takes preventive action, then there is no non-compliance because the RA has achieved its objective of operating within IROLs. The system operator needs to take proactive actions to prevent exceeding an IROL for an 'emerging' condition.
</td></tr>
<tr><td>
James Murphy; BPAT;#1
Mike Viles; BPAT; #1
Richard Spence; BPAT; #1
Don Watkins; BPAT; #1
Don Gold; BPAT; #1
Marv Landauer; BPAT; #1
</td><td>
BPAT would like the system operator to be identified as RA system operators where applicable. 202(b)(3) & 202(d)(3)(i)
In section 200 (2) please identify the name of section 604 where used.
Please add the standard number when other standards are mentioned.
Please include in 208 (d) (3) "(4) Time the actions were taken. This may be important to determine if directive were followed in a timely manner.
</td></tr>
<tr><td colspan="2">

The word, 'its' has been added to the 202(b)(3) and 2020(d)(3)(i) to clarify that the system operators are the RA's system operators.
The reference to Standard 600 has been deleted because the requirement to identify IROLs has been transferred to Standard 600.
Logging the date and time is considered, 'good utility practice' and shouldn't have to be specifically proscribed.

</td></tr>
<tr><td>
Patti Metro; FRCC; #2
Linda Campbell ;FRCC ;#2
Steve Wallace; Seminole Electric Coop ;#4
Amy Long; Lakeland Electric; #1
Richard Gilbert; Lakeland Electric; #3
Ron Donahey; Tampa Electric Company; #3
Beth Young; Tampa Electric Company ;#3
Roger Hunnicutt ; Gainesville Reg Utl; #5
Roger Westphal ;City of Gainesville; #3
Greg Woessner ;Kissimmee Utility Auth;#3
Ben Sharma ;Kissimmee Utility Auth;#3
Garry Baker; JEA ;#1
Ed DeVarona; Florida Power & Light Co. ;#1
Preston Pierce; Progress Energy Florida ;#1
Bob Remley; Clay Electric Cooperative; #4
Joe Krupar; FMPA; #3
Paul Elwing; Lakeland Electric; #5
</td><td>
1. The Compliance Monitoring Process for 202-208 requires that certain information be provided to the Compliance Monitor "upon request", but does not indicate how long the Reliability Authority has to provide the information. A possible revision could be that " upon request the Reliability Authority will provide the following information to the Compliance Monitor within 5 business days".
204
Requirements
2. Who is responsible for implementing an IROL mitigation plan? Transmission Owner? RA? Does the RA develop the plan or the Transmission Owner?
3. Footnote 2 indicates the no action "may be acceptable as long as it is documented", what type of documentation is required?
4. Non-Compliance Level 4 - Should be revised to indicate that the Reliability Authority is non-compliant because no actions were taken to mitigate an IROL or to document the violation.
205
</td></tr>
</table>

Joe Roos; Ocala Electric Utility ;#3	5. Measure (3)(i) should be revised to indicate that the Compliance Monitor should be notified within five business days of determining the data issue could not be resolved. 6. Non-compliance levels – Why is there a Level 1 and Level 2, rather that Level 3 and Level 4. It appears that this information is very important to maintain a reliable system. In additions, if there is a measure for notifying the Compliance Monitor when data issues cannot be resolved, a level of non-compliance should be included when this notification is not provided. 207 7. Requirements and Levels of Non-Compliance – from this it appears that the Reliability Authority will work with other entities to develop processes, procedures, and plans, but the levels of non-compliance indicated that these activities could be developed with no input. What good is this if an Reliability Authority can't perform the mitigation? Seems very broad and burdensome to the Reliability Authority. 208 8. Requirements - The standard does not address seams issues. Although 201 requires Reliability Authorities that share facilities to develop IROL procedures and lists there needs to be a requirement included that would allow one Reliability Authority to give directives to another Reliability Authority. 9. Levels of Non-Compliance – If an entity does not follow the Reliability Authority directive, and the Reliability Authority does not have the ability to take action, other than the financial penalty there is no way to make entities comply with directives and reliability will be jeopardized.

1. The term, "on request" was intended to mean during an audit. The standard has been changed to indicate this more clearly. 2. The RA is responsible for having the processes, procedures or plans and for implementing them. The standard is silent on who needs to develop the plan. Currently, at least one of the regions has a technical committee that develops some of these documents for use in a sub-region or region-wide basis. 3. The documentation in footnote 2 is the operator log or other data source addressed in measure 204(b)(1)(i). 4. The purpose of this standard is to prevent an IROL from ever being exceeded. There are two ways an IROL can be exceeded – as a result of an emerging event that the RA failed to control – or as a result of a serious incident where the RA wasn't able to direct actions quickly enough to resolve the incident within the IROL's Tv. The industry was asked to endorse this approach in an earlier posting, and the most industry commenters agreed that the RA should be held accountable for the results of actions. 5. Your suggestion was implemented and is reflected in the revised standard. 6. The SDT could not identify a method for determining that data hadn't been provided and the Compliance Monitor hadn't been notified. 6. Since most commenters indicated support for these levels of non-compliance, the SDT did not change them. 7. If the processes, procedures or plans are developed without coordination with entities that are required to take actions, then the RA is non-compliant. The RA needs to ensure that the entities that are expected to take actions under specified conditions (with respect to IROLs) are aware, in advance, of the conditions and the actions that need to be taken. 8. Under the Functional Model, all RAs are created equal. Developing a requirement that gives one RA the authority to direct the actions of another RA is outside the scope of the Functional Model. However, under the processes, procedures and plans, there may be documents that outline a process agreed upon by all involved RAs. There is another standard, Coordinate Operations between RAs that addresses the more complex coordination that takes place between RAs in support of interconnection reliability. This standard's focus is on the actions the RA takes to control its own RA Area with respect to monitoring and operating so that no IROLs are exceeded. The SDT modified Requirement 201 to better address the seams issues when establishing which Facilities are subject to IROLs, and when establishing IROLs for those Facilities. 9. Agreed. Financial sanctions are intended to provide incentive to follow the RA's directives. If an entity doesn't take the actions requested, the RA needs to be ready to direct other actions to protect the reliability of the interconnection - up to and including issuing a directive to drop firm load. The RA needs to have the authority to issue directives and have those directives followed. Each RA may have agreements with entities under its direction that include language that addresses the 'passing on' of any financial sanctions due to lack of compliance with the RAs directives. Ensuring reliability is the RA's objective.

Lawrence Hochberg; NYSRC; #2 Ralph Rufrano; NYPA; #1 David Kiguel; Hydro One Networks Inc.; #1 Roger Champagne; H-Q TransÉnergie; #1 Greg Campoli; New York ISO (NYISO); #2 Peter Lebro; National Grid; #1 Kathleen Goodman; ISO-NE; #2 Dan Stosick; ISO-NE;#2 Al Adamson; NYSRC;#2	1. The footnote on Std 201 states that each IROL is developed by following the requirements in "Determine Facility Ratings, SOL's & Transfer Capabilities" i.e. Std 600. Such requirements with respect to IROL are not mentioned in Std 600, and it is expected that upcoming revised standard shall include this requirement otherwise it is recommended to delete the keynote from this standard 200. 2. Owing to the fact that "Tv" value can be smaller than 30 minutes, it is suggested to update the sub-section 203 (b) (ii) as follows: " The Reliability authority shall conduct a Real-time Assessment

Khagan Khan; The IMO Ontario; #2 Brian Hogue; NPCC;#2 Guy Zito; NPCC;#2 Greg Campoli; NYISO; #2 James Castle; NYISO ;#2 John Ravalli; NYISO; #2 Karl Tammar; NYISO; #2 Robert Waldele; NYISO; #2 Michael Calimano; NYISO; #2	periodically, once every 30 minutes or lesser as applicable in order to capture the allowable lesser duration Tvs. 3. General comment on the standard is it seems overly burdensome with documentation and less focused on performance. 4. Examples regarding the individual definitions might be helpful to be added in an accompanying document. 5. The Standard should address repeated, planned IROL violations that don't exceed or consistently approach Tv and preventing this/discouraging this mode of operation from reoccurring. It is not OK to exceed IROLs and there are entities that frequently exceed them for short periods of time for economic or other reasons, they are not reportable because they do not exceed Tv. This behavior must be discouraged through measurement of frequency and severity of IROL through the reporting mechanisms outlined in this standard, and as outlined in new template P2 T1 "System Operating/IROL Violations". In addition, there were no IROL Tv violations reported to NERC as a result of the events occurring on August 14th 2003 which implies either more stringent reporting is required or the IROL and Tv limit needs to be reevaluated.
1. The footnote was added at the request of many industry commenters and has been modified to reference the specific requirement in standard 600. Since the requirement to identify IROLs was transferred to the Determine Facility Ratings Standard, the footnote is not in the revised standard. 2. The frequency of real-time assessments was not intended to be tied to T_v. This standard does not preclude an RA from conducting a real-time assessment more frequently than once every 30 minutes. Some IROLs may have a very short $T_{v'}$ - T_v could be as short as a minute or less – and requiring a real-time assessment to be conducted this frequently would not be practical. 3. Please be more specific about which aspects you feel are burdensome. 4. Please be more specific about what examples you feel should be added. 5. While entities do exceed SOL's, there is little evidence to support the statement that entities routinely exceed IROLs. If an entity is aware of an RA that allows IROLs to be routinely exceeded, the Compliance Monitor should be notified so that an investigation can be conducted. The revised standard requires more coordination with adjacent RAs, and this should help put better controls over the amount of risk tolerated. There were many different violations that occurred on August 14.	
Kathleen Goodman; ISO-NE; #2	1. The standard seems to be measured more on documentation than performance. Our concern is that the requirements to document may delay action and response time, therefore adversely impacting reliability. The standard should focus on performance and not whether every log entry was made in the correct format.

	2. The standard should be reviewed to ensure that all references to IROLs include the word "operating" if the definition will move forward as IROL vs. IRL (note that Attachment A to NERC's recommendation 1 from August 14th uses IRL, not IROL). Consistency needs to be applied. 3. The Phased-in implementation in 200 does not make sense: if the data is not obtained for 12 months, how can the monitoring, actions, etc. begin in six months? 4. While ISO New England generally agrees with a quick implementation of the final approved Standard, there is a large amount of specific data that must be collected and stored to meet the full intent of the Standard. Depending upon what the final approved Standard is, this may require additional software and business processes to fully implement. For this reason we believe that an implementation plan must provide a development period for the responsible entities to fully implement the standard. 5. There is an issue with the concept of a monetary sanction matrix and what its implications are. ISO-NE, as well as NPCC, has expressed concern over its inclusion and maintains that the use of market mechanisms where possible, as well as, letters of increasing degrees of severity and notifications to regulatory agencies are more effective in ensuring compliance. Failure of NERC to gain authority through reliability legislation could result in NERC pursuing actions to implement "Plan B," a "voluntary" approach affording NERC the authority to perform these types of monetary sanctions. ISO-NE has indicated that any posted Standard, with such a matrix, will not be supported by ISO-NE. There are, however, proceedings at NERC by the Compliance Certification Committee (CCC) to address alternative sanction proposals and ISO-NE will continue to work to oppose monetary sanctions. 6. ISO New England believes that this standard should provide clear examples within this standard, describing in detail what constitutes a violation that must be reported along with clear examples of what constitutes and SOL and IROL. Examples should include contingency pair examples for both IROL and SOL thermal limits as well as examples concerning stability and voltage limits.
1. Please be more specific in identifying areas where you feel the documentation required is inappropriate. The SDT does not believe that the documentation requirements in this standard are more involved than what should be currently documented. 2. The SDT did not write the NERC's recommendations on the August 14th events. 3. The standard assumes that the RA functions are already being performed by some entity, and some entity is already monitoring and collecting data. The reason the SDT suggested a longer implementation	

<table>
<tr><td colspan="2">time for compliance with the data spec requirement was to recognize that some entities may need some time to formalize their data specifications.

4. The standard assumes that the RA functions are already being performed by some entity, and some entity is already monitoring and collecting data. Additional time has been allowed for creating specifications – the standard doesn't require any software or business processes that aren't already required to meet current Operating Policies.

5. The SDT has no authority to remove financial sanctions from the Sanctions Table.

6. The format of the new standards, approved with the Reliability Standards Process Manual, requires very clear, succinct topical sections. Please reference the RSPM pages ---- to see what is required. The VP-General Counsel for NERC has advised the SDT's to refrain from adding material to the standards that exceeds the topics identified in the RSPM.</td></tr>
<tr><td>Ralph Rufrano; NYPA; #1
David Kiguel; Hydro One Networks Inc.; #1
Roger Champagne; H-Q TransÉnergie; #1
Greg Campoli; New York ISO (NYISO); #2
Peter Lebro; National Grid; #1
Kathleen Goodman; ISO-NE; #2
Dan Stosick; ISO-NE;#2
Al Adamson; NYSRC;#2
Khagan Khan; The IMO Ontario; #2
Brian Hogue; NPCC;#2
Guy Zito; NPCC;#2</td><td>(NPCC Members of CP9 expressed concern over these questions 18-19-and 20. The answers to them are more "process" related than standard related and seem inappropriate. Are differing weights assigned to persons, and their answers, who are not voting in the pool? These questions could raise issues about the process being open and inclusive.)</td></tr>
<tr><td colspan="2">The intent of asking these questions was to see if there were enough industry balloters who would oppose any standard based on issues outside the SDT's control so that the SDT could decide whether to delay balloting until these issues (i.e. the future of the Reliability Coordinator, the difference between the RC and the RA, financial sanctions, field testing) are resolved.</td></tr>
<tr><td>Al Corbet; TVA
Jerry Landers; TVA
Jennifer Weber; TVA
Edd Forsythe; TVA
Larry Goins; TVA
Mark Creech; TVA
Kathy Davis; TVA</td><td>TVA would like to reserve the right to forward additional comments at a later date.</td></tr>
<tr><td>Jalal Babik; Dominion VA Power; #1
Craig Crider; Dominion VA Power; #1
Jack Kerr; Dominion VA Power; #1
Bill Thompson; Dominion VA Power; #1</td><td>The Board approved a new compliance template that applies to the issues covered by this proposed standard on April 2, 2004. The compliance template that is now approved conflicts with the compliance presented here. I want to know where this is heading. Also see comments under item 9.</td></tr>
<tr><td colspan="2">The SDT understands that the compliance templates were short-term 'fixes' to provide FERC and the industry with a set of 'measurable' elements needed to support reliability. These templates did not go through the same level of 'due process' required by the ANSI accredited NERC Reliability Standards Development Process and were not intended to supersede these new standards. When this standard is approved, adopted, and implemented, the associated compliance templates will be retired. When the NERC BOT approved the templates, the BOT also directed that the SDT's continue to develop the new</td></tr>
</table>

reliability standards, following the ANSI process. See response under question 9.

Dan Boezio; AEP; #1 Ron Ciesiel; SPP; #2 Bob Cochran; SPS; #1 Mike Gammon; KCP&L; #1 Allen Klassen; Westar; #1 Peter Kuebeck; OG&E; #1 Mike Stafford; GRDA; #1 Robert Rhodes; SPP; #2 Scott Moore; AEP; #1	1. An IROL of 300 MW of load loss is too small. Don't lose sight of the fact that an IROL is a significant threat to a large portion of the interconnection. By minimizing the defined threshold for an IROL, the number of IROLs will increase drastically and thereby dilute the significance of the event. 2. Section 203(b)(1)(ii) requires a real-time assessment at least every 30 minutes. This may be too frequent depending upon the complexity of the studies involved. 3. Consider reversing noncompliance Levels 3 and 4 in section 203(e). Which of the two levels is worse?
1. Agreed. The SDT modified the standard to respect this concept. 2. The industry was asked to identify whether 30 minutes was appropriate, and there was consensus on requiring that these be conducted at least once every 30 minutes. This is an assessment, and not necessarily a 'study'. 3. The SDT modified these levels of non-compliance to clarify what was intended. As revised, it should be clear that level 4 is worse than level 3.	
Alan Gale; City of Tallahassee; #5 Rusty Foster; City of Tallahassee; #3	1. The Compliance Monitoring Process for 202-208 requires that certain information be provided to the Compliance Monitor "upon request". There should be some consistency across all the standards for time frames of "requested data". Without it, the Compliance Monitor can get the run around for a month and the reporting entity can still be compliant. 203 2. Requirements and Measures - Although not specified in the Requirements, the Measures requires an Operational Planning Analysis at least once each day for the "projected system operating conditions". This would preclude a "day ahead" analysis of the weekend (or holiday) from being performed on Friday. A provision should be made that would allow this. Trigger a required analysis if system conditions differed from the analyzed conditions. (i.e. a line was planned to be out Saturday only, but remains out on Sunday would trigger a new analysis. If the line was back in, it would not require an analysis be done on Saturday for Sunday, the analysis on Friday would remain valid.) 204 Requirements 3. Who is responsible for implementing an IROL mitigation plan? Transmission Owner? RA? Does the RA develop the plan or the Transmission Owner? 4. Footnote 2 indicates the no action "may be acceptable as long as it is documented", what type of documentation is required? 5. If "no overt action" is acceptable, is it an IROL? 205 6. Measure (3)(i) should be revised to indicate that the Compliance Monitor should be notified within five business days of determining the data issue could not be resolved. 7. Non-compliance levels – Why is there a Level 1 and Level 2, rather that Level 3 and Level 4. It appears that this information is very important to maintain a reliable system. In additions, if there is a measure for notifying the Compliance Monitor when data issues cannot be resolved, a level of non-compliance should be included when this notification is not provided.

	206 8. Non-Compliance Level 4 - Should be revised to separate "not providing the data" from the "inability to resolve the issue". The inability to send the data due to a technical problem that is being upgraded should be differentiated from the refusal to provide the data ("inability to resolve"). This will allow a lower level of non-compliance while pursuing any necessary equipment or technology upgrades. 207 9. Requirements and Levels of Non-Compliance – from this it appears that the Reliability Authority will work with other entities to develop processes, procedures, and plans, but the levels of non-compliance indicated that these activities could be developed with no input. What good is this if an Reliability Authority can't perform the mitigation? Seems very broad and burdensome to the Reliability Authority. 10. There should be some consistency across all the standards for time frames of "reviewing or updating". Without it, an entity can only review its documents and programs "at will" and still be compliant 208 11. Requirements - The standard does not address seams issues. Although 201 requires Reliability Authorities that share facilities to develop IROL procedures and lists, there needs to be a requirement included that would allow one Reliability Authority to give directives to another Reliability Authority. 12. Levels of Non-Compliance – If an entity does not follow the Reliability Authority directive, and the Reliability Authority does not have the ability to take action, other than the financial penalty there is no way to make entities comply with directives and reliability will be jeopardized.

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<tr><td colspan="2">
1. The term, “on request” was intended to mean during an audit. The standard has been changed to indicate this more clearly.
2. The standard doesn’t specify how detailed each of these analyses and assessments needs to be – but they should be done to verify the expected conditions – the operational analysis should be done at least once a day – and the real-time assessment should be done at least once every 30 minutes.
The operational planning analysis does not need to include a stability analysis unless – whether or not a stability analysis should be conducted is left up to the RA. It would be unrealistic to expect the RA to conduct a stability study each day, and this is not what was intended.
3. The RA is responsible for having the processes, procedures or plans and for implementing them. The standard is silent on who needs to develop the plan. Currently, at least one of the regions has a technical committee that develops some of these documents for use in a sub-region or region-wide basis.
4. The documentation in footnote 2 is the operator log or other data source addressed in measure 204(b)(1)(i).
5. If an RA sees that a planned action, such as the addition of another unit, is scheduled to occur, and the addition of the unit will reduce loading on a line that is approaching its IROL, the RA may elect to take ‘no action’ because the RA knows that if all goes as planned, the limit won’t be exceeded. – but the IROL would still be an IROL.
6. Your suggestion was implemented and is reflected in the revised standard.
7. The SDT could not identify a method for determining that data hadn’t been provided and the Compliance Monitor hadn’t been notified.
8. The standard allows the RA the flexibility of determining when the issue needs the intervention of the Compliance Monitor. It also allows for alternative methods for collecting data.
9. If the processes, procedures or plans are developed without coordination with entities that are required to take actions, then the RA is non-compliant. The RA needs to ensure that the entities that are expected to take actions under specified conditions (with respect to IROLs) are aware, in advance, of the conditions and the actions that need to be taken.
10. Since the new standards are being developed in parallel, and the importance of requirements are not equal from standard to standard, mandating that all standards contain the same review periods doesn’t seem practical – and implementing such a system is outside the control of the SDT.
11. Under the Functional Model, all RAs are created equal. Developing a requirement that gives one RA the authority to direct the actions of another RA is outside the scope of the Functional Model. However, under the processes, procedures and plans, there may be documents that outline a process agreed upon by all involved RAs.
There is another standard, Coordinate Operations between RAs that addresses the more complex coordination that takes place between RAs in support of interconnection reliability. This standard’s focus is on the actions the RA takes to control its own RA Area with respect to monitoring and operating so that no IROLs are exceeded. The SDT modified Requirement 201 to better address the seams issues when establishing which Facilities are subject to IROLs, and when establishing IROLs for those Facilities.
12. Agreed. Financial sanctions are intended to provide incentive to follow the RA’s directives. If an entity doesn’t take the actions requested, the RA needs to be ready to direct other actions to protect the reliability of the interconnection - up to and including issuing a directive to drop firm load. The RA needs to have the authority to issue directives and have those directives followed. Each RA may have agreements with entities under its direction that include language that addresses the ‘passing on’ of any financial sanctions due to lack of compliance with the RAs directives. Ensuring reliability is the RA’s objective.
</td></tr>
<tr><td>Gerald Rheault; Manitoba Hydro; #1,3,5,6</td><td>1. Manitoba Hydro believes that this Standard should be field tested prior to implementation. This will ensure that all elements of the Standards are relevant to the operational reliability of the bulk</td></tr>
</table>

	electric system and can be implemented in a straightforward manner. 2. In section 203 (d) Compliance Monitoring Process item (3) (i) it makes more sense that the RA provide evidence that Operational Planning Analysis occurs at least once a day and what the results were rather than indicating only the most recent analysis. Similar comments for 203 (d) (3) (iii). The evidence could be in the form of a log. 3. In section 205 (b) Measures, there is no measure to establish that the RA is notifying its Compliance Monitor when data is not provided or data collection issues are not resolved. In section 205 (d) Compliance Monitoring Process, there is no check that the RA is notifying its Compliance Monitor when data is not provided or data collection issues are not resolved. There are no sanctions for not complying.
1. The determination of whether field testing is needed is made by the SAC in consultation with the VP-Director-Compliance. The SDT does not have any authority over whether field testing is conducted. 2. The SDT asked the industry for support of the compliance monitoring, and most industry commenters indicated they do support the language in the standard, so this was not changed. 3. Agreed – the SDT couldn't identify a way to measure non-compliance with this requirement, but the requirement is needed to 'trigger' an investigation by the Compliance Monitor to motivate whatever entity is not providing the necessary data.	
Lee Xanthakos; SCE&G; #1	I agree with the requirements of RAs as defined by this standard as long as my organization becomes an RA. If we cannot receive RA certification then I would not agree with the requirement because state regulatory issues do not allow my organization to transfer to someone else the RA responsibility defined here that we currently do.
The SDT has no control over which entity will/will not become an RA. We do appreciate the many comments you provided on this standard.	