



NORTH AMERICAN ELECTRIC  
RELIABILITY CORPORATION

# Agenda

## Member Representatives Committee

May 10, 2011 | 1:00–4:45 p.m. ET  
The Westin Arlington Gateway  
801 Glebe Road  
Arlington, VA  
703-717-6200

### Introductions and Chairman's Remarks

### NERC Antitrust Compliance Guidelines and Public Meeting Notice

### Consent Agenda — Approve

#### 1. Minutes\*

- a. [April 13, 2011 conference call](#)
- b. [February 16, 2011 meeting](#)

#### 2. Future Meetings\*

### Regular Agenda<sup>1</sup>

#### 3. Remarks by Gerry Cauley, NERC President and CEO

#### 4. Recommended Slate of MRC Members to Serve on the Board of Trustees Nominating Committee\*

#### 5. Bulk Electric System Definition\*

- a. [BES Definition SDT – Pete Heidrich](#)
- b. [BES ROP Team – Carter Edge](#)
- c. BES/ALR Policy Issues Task Force – Bill Gallagher

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<sup>1</sup> Board Chairman John Q. Anderson has invited input from the committee sector representatives on specific agenda items (see attached).

- 6. Analysis of Cold Weather Impacts on the Bulk Power System\***
- 7. Facility Ratings Alert Responses and Next Steps\***
- 8. Event Analysis Process Improvements\***
- 9. ERO Enterprise Performance Metrics\***
- 10. Comments by Observers**
- 11. Items for August 2011 MRC Agenda**
- 12. 2012 Business Plan and Budget – will be provided under separated cover**

**Information Only — No Discussion**

- 13. Update on Regulatory Matters\***

\*Background material included.

## Antitrust Compliance Guidelines

### I. General

It is NERC's policy and practice to obey the antitrust laws and to avoid all conduct that unreasonably restrains competition. This policy requires the avoidance of any conduct that violates, or that might appear to violate, the antitrust laws. Among other things, the antitrust laws forbid any agreement between or among competitors regarding prices, availability of service, product design, terms of sale, division of markets, allocation of customers or any other activity that unreasonably restrains competition.

It is the responsibility of every NERC participant and employee who may in any way affect NERC's compliance with the antitrust laws to carry out this commitment.

Antitrust laws are complex and subject to court interpretation that can vary over time and from one court to another. The purpose of these guidelines is to alert NERC participants and employees to potential antitrust problems and to set forth policies to be followed with respect to activities that may involve antitrust considerations. In some instances, the NERC policy contained in these guidelines is stricter than the applicable antitrust laws. Any NERC participant or employee who is uncertain about the legal ramifications of a particular course of conduct or who has doubts or concerns about whether NERC's antitrust compliance policy is implicated in any situation should consult NERC's General Counsel immediately.

### II. Prohibited Activities

Participants in NERC activities (including those of its committees and subgroups) should refrain from the following when acting in their capacity as participants in NERC activities (e.g., at NERC meetings, conference calls and in informal discussions):

- Discussions involving pricing information, especially margin (profit) and internal cost information and participants' expectations as to their future prices or internal costs.
- Discussions of a participant's marketing strategies.
- Discussions regarding how customers and geographical areas are to be divided among competitors.

- Discussions concerning the exclusion of competitors from markets.
- Discussions concerning boycotting or group refusals to deal with competitors, vendors or suppliers.
- Any other matters that do not clearly fall within these guidelines should be reviewed with NERC's General Counsel before being discussed.

### **III. Activities That Are Permitted**

From time to time decisions or actions of NERC (including those of its committees and subgroups) may have a negative impact on particular entities and thus in that sense adversely impact competition. Decisions and actions by NERC (including its committees and subgroups) should only be undertaken for the purpose of promoting and maintaining the reliability and adequacy of the bulk power system. If you do not have a legitimate purpose consistent with this objective for discussing a matter, please refrain from discussing the matter during NERC meetings and in other NERC-related communications.

You should also ensure that NERC procedures, including those set forth in NERC's Certificate of Incorporation, Bylaws, and Rules of Procedure are followed in conducting NERC business.

In addition, all discussions in NERC meetings and other NERC-related communications should be within the scope of the mandate for or assignment to the particular NERC committee or subgroup, as well as within the scope of the published agenda for the meeting.

No decisions should be made nor any actions taken in NERC activities for the purpose of giving an industry participant or group of participants a competitive advantage over other participants. In particular, decisions with respect to setting, revising, or assessing compliance with NERC reliability standards should not be influenced by anti-competitive motivations.

Subject to the foregoing restrictions, participants in NERC activities may discuss:

- Reliability matters relating to the bulk power system, including operation and planning matters such as establishing or revising reliability standards, special operating procedures, operating transfer capabilities, and plans for new facilities.
- Matters relating to the impact of reliability standards for the bulk power system on electricity markets, and the impact of electricity market operations on the reliability of the bulk power system.
- Proposed filings or other communications with state or federal regulatory authorities or other governmental entities.
- Matters relating to the internal governance, management and operation of NERC, such as nominations for vacant committee positions, budgeting and assessments, and employment matters; and procedural matters such as planning and scheduling meetings.

## Draft Conference Call Minutes Member Representatives Committee

April 13, 2011 | 12:30 p.m.–1:30 p.m. (Eastern)

Chairman Bill Gallagher convened a duly-noticed open meeting by conference call of the North American Electric Reliability Corporation's Member Representatives Committee (MRC) on April 13, 2011 at 12:30 p.m. (Eastern). The meeting announcement, agenda, and list of attendees are attached as **Exhibits A, B, and C**, respectively. No roll call was taken and no quorum was required.

### **NERC Antitrust Compliance Guidelines and Public Meeting Notice**

David Nevius, committee secretary, directed the participants' attention to the NERC Antitrust Compliance Guidelines and the public meeting notice.

### **Review of May 10, 2011 Draft MRC Agenda**

Chairman Gallagher reviewed the preliminary agenda for the upcoming May 10, 2011 MRC meeting in Arlington, VA (**Exhibit D**).

Chairman Gallagher:

- Reminded participants the MRC Informational Session Conference Call and Web Meeting will take place on May 5, 2011;
- Reviewed John Q. Anderson's letter regarding Policy Input and stated the deadline for comments is May 5, 2011. Policy input was requested on the following topics:
  - Bulk Electric System (BES) and Adequate Level of Reliability (ALR) Definitions
  - Facility Ratings Alert Responses and Next Steps
  - Event Analysis Process Improvements
  - NERC Metrics
  - 2012 Business Plan and Budget
- Confirmed future meeting dates, February 8–9, 2012, and noted this will require MRC approval at the May 10, 2011 meeting;
- Stated that the 2012 Business Plan and Budget will be posted April 29 for review and will be discussed during the May 10 MRC meeting;

- Requested recommendations for MRC members to the Board of Trustees Nominating Committee (BOTNC). The process will begin August 2011 at the MRC/BOT meeting and will go through series of meetings and calls.

**Review of May 11, 2011 Draft Board of Trustees (BOT) Agenda**

Dave Nevius reviewed the preliminary agenda for the May 11, 2011 Board of Trustees meeting in Arlington, VA (**Exhibit E**).

**Review of May 10, 2011 Board of Trustees Compliance Committee (BOTCC) Agenda**

Mr. Nevius reviewed the preliminary agenda for the Board Compliance Committee. (**Exhibit F**).

**Schedule of Upcoming Board Committee Conference Calls and Meetings**

Chairman Gallagher reviewed the schedule of upcoming board committee conference calls and meetings (**Exhibit G**).

Chairman Gallagher noted there will be a formal sit down dinner in place of the cocktail reception for this May 10, 2011 meeting. Formal dinner and cocktail receptions will alternate between meetings.

**Meeting Adjourned**

There being no further business, the call was terminated at 1:00 p.m. Eastern.

Submitted by,

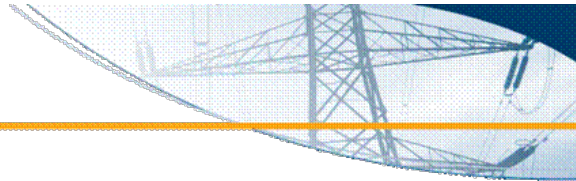


David R. Nevius  
Committee Secretary



From: [Elizabeth Merlucci](mailto:Elizabeth.Merlucci@nerc.net)  
To: [Elizabeth Merlucci](mailto:Elizabeth.Merlucci@nerc.net)  
Subject: NERC AGENDA: Member Representatives Committee (MRC) - BES/ALR Policy Issues and MRC Pre-Meeting Conference Call  
Date: Monday, April 11, 2011 1:45:16 PM

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## Agenda

### Two-Part Conference Call

### Member Representatives Committee (MRC)

#### BES/ALR Policy Issues Conference Call and MRC Pre-Meeting Conference Call

Wednesday, April 13, 2011 | 11 a.m.–1:30 p.m. (Eastern)

\*Please note that dial-In information was sent under separate cover.

BES/ALR Policy Issues Conference Call agenda now available at: <http://www.nerc.com/docs/mrc/MRC-041311-cca.pdf>

MRC Pre-Meeting Conference Call agenda now available at: [http://www.nerc.com/docs/mrc/MRC-04-13-11-cca\\_Complete\\_Pkg.pdf](http://www.nerc.com/docs/mrc/MRC-04-13-11-cca_Complete_Pkg.pdf)

The MRC will hold a two-part conference call on **Wednesday, April 13, 2011, from 11 a.m.–1:30 p.m. Eastern Time.**

The first part of the call will be devoted to discussion of policy issues and questions associated with the definitions of Bulk Electric System (BES) and Adequate Level of Reliability (ALR). While all voting and non-voting members of the MRC are welcome on this part of the call, the primary emphasis will be on discussion of the draft work products of the recently formed MRC BES/ALR Policy Issues Task Force.

The second part of the call will be the regular quarterly MRC pre-meeting conference call to review the agendas for the May 10–11, 2011 meetings of the MRC, Board of Trustees, and Board committees. This part of the call will begin at approximately 12:30 p.m. and conclude in about one hour.

David R. Nevius  
MRC Secretary

Liz Merlucci  
North American Electric Reliability Corporation  
116-390 Village Blvd.  
Princeton, NJ 08540  
609.524-7038 | [www.nerc.com](http://www.nerc.com)  
[elizabeth.merlucci@nerc.net](mailto:elizabeth.merlucci@nerc.net)

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You are currently subscribed to mrc\_plus as: [elizabeth.merlucci@nerc.net](mailto:elizabeth.merlucci@nerc.net)  
To unsubscribe send a blank email to [leave-1253879-279343.9b72a5047d21f99d4d0fd4bc669c2d82@listserv.nerc.com](mailto:leave-1253879-279343.9b72a5047d21f99d4d0fd4bc669c2d82@listserv.nerc.com)

# NERC

NORTH AMERICAN ELECTRIC  
RELIABILITY CORPORATION

Exhibit B

## Agenda

### Member Representatives Committee (MRC) Pre-Meeting Conference Call

April 13, 2011 | 12:30 p.m. (Eastern)

Dial-In number has been provided under separate cover

#### **Introductions and Incoming Chairman's Remarks**

#### **NERC Antitrust Compliance Guidelines and Public Meeting Notice**

- 1. MRC Draft Agenda Review\***
- 2. Board of Trustees Draft Agenda Review\***
- 3. Board of Trustees Compliance Committee Draft Agenda Review\***
- 4. Chairman's Anderson's Request for Policy Input\***
- 5. Request for Recommendations to BOT Nominating Committee**
- 6. Preliminary Schedule of Meetings\***

\*Background material included.



### MRC BES/ALR Policy Issues and MRC Pre Meeting Call

Reservation Number: 21519795

Reservation Date/Time: 04-13-2011 1

Chair Person: DAVID NEVIUS

Total Number of Lines: 158

Company Name: N AMER ELECTRIC RELIABILITY CORP

	First Name	Last Name	Company	Are you a member of MRC?
1	Mark	Ackerson	Freescall	No
2	Charles	Acquard	NASUCA	Yes
3	Roshanak	Afalatouni	California Department of Water	No
4	John	Allen	City Utilities of Springfield	No
5	John	Anderson	ELCON	Yes
6	Tom	Anderson	Tacoma Power	Yes
7	Johnathan	Appelbaum	United Illuminating	No
8	David	Areghini	Salt river Project	Yes
9	Tim	Art	N P P D	Yes
10	Jeff	Bailey	Dominion Resources	No
11	Vickie	Bailey	NERC Board	No
12	Eric	Baker	Wolverine Power Cooperative	Yes
13	Chris	Best	Nav Canada	No
14	Tracy	Bibb	Northern California Power	No
15	Larry	Brusseau	Mappcor	No
16	Linda	Brzezinski	C M S Enterprises	No
17	Denis	Burbin	T G & E	No
18	Thomas	Burgess	First Energy	Yes
19	Marc	Butts	Southern Co	No
20	Gary	Carlson	Michigan Public Power	No
21	Jack	Cashin	EPSA	Yes
22	Gerry	Cauley	NERC	No
23	Carol	Chinn	A T C	Yes
24	Lisa	Cleary	Colorado Springs Utilities	No
25	AJ	Connor	N E R C	No
26	David	Cook	NERC	No
27	William	Coyle	Demi Marketing Inc	No
28	Craven	Crowell	Texas R E	Yes
29	Michelle	D'Antuono	Occidental	Yes
30	Edward	Davis	Entergy	No
31	Brian	Davison	Public Utility Commission	No
32	John	DiSasio	Sacramento Municipal	Yes
33	Stacy	Dochoda	S P P R E	Yes
34	A J	Doug	Hydro One	Yes - Proxy for Carmine Marcello
35	Douglas	Draeger	Alameda Municipal Power	No
36	Gregg	Duke	Richmond Power & Light	No
37	David	Dworzak	E E I	No
38	Carter	Edge	SERC	No
39	David	Ellington	Gridspeak Corp	No
40	John	Fish	Trans Canada	No
41	Tom	Florence	U A M P S	No
42	Michael	Frazier	Piedmont Municipal Power	No
43	William	Gallagher	MRC Chair	Yes
44	Tim	Gallagher	Reliability First Corp	No
45	Tom	Galloway	NERC	No

46	Tab	Gangopadhyay	National Energy Board	Yes
47	Michael	Gilday	Dominion Resources	No
48	David	Godfrey	W E C C	No
49	David	Gordon	M M W E C	No
50	Shawn	Grassman	Gridspeak Corp	No
51	Larry	Grimm	Texas R E	No
52	James	Gundersen	Northern California Power	No
53	Jeff	Gust	Mid-American	No
54	Jeff	Hackman	Ameren	No
55	Wade	Hairschi	Lower Valley Energy	No
56	Lisa	Hairston	Avista Corporation	No
57	Rick	Hansen	St George City	No
58	Pete	Heidric	FRCC	No
59	Randy	Heise	Dominion Resources	No
60	Scott	Helyer	MRC Vice Chair	Yes
61	Scott	Henry	SERC	No
62	Pat	Hervochon	P S E G Nuclear	No
63	Mike	Hirst	Cogentrix Energy	No
64	Nabil	Hitti	National Grid	No
65	Sam	Holeman	Duke Energy	No
66	Chip	Humphrey	Dominion Resources	No
67	Susan	Ivey	Exelon	Yes
68	Linda	Jacobson	City of Farmington	No
69	Denise	James	Demi Marketing Inc	No
70	Matt	Jastram	P G E	No
71	Melvin	Jensen	A P S	No
72	Michael	Gildea	Dominion Resources	No
73	Douglas	Johnson	American Transmission Co	No
74	Hardev	Juj	B P A	No
75	Barb	Kedrowski	We Energies	No
76	Jim	Keller	Wisconsin Electric	No
77	James	Kendall	S M U D	No
78	Dan	Klempel	Basin Electric Power	No
79	Jean	Kurzynowski	Consumers Energy	No
80	Jose	Landeros	Imperial Irrigation District	No
81	Mark	Lauby	NERC	No
82	Barry	Lawson	N R E C A	No
83	Don	Lekang	North American Transmission Forum	No
84	Jill	Loewer	Utility Svcs	No
85	Michael	Lombardi	Northeast Utilities	No
86	Robin	Lunt	NARUC	Yes
87	Corrina	Markley	Tacoma Power	No
88	Cindy	Martin	Southern Co	No
89	Eddie	Martinez	Demi Marketing Inc	No
90	Robert	Martinko	First Energy	No
91	Dan	Mason	Hetch Hetchy	No
92	Sharon	Mayers	Southern California Edison	No
93	Kerry	McAlman	US Bureau of Reclamation	No
94	Elizabeth	Merlucci	N E R C	No
95	Lorne	Midford	Manitoba Hydro	Yes
96	Katy	Mirr	Sempra Generation	Yes
97	Michael	Moltane	I T C	No

98	Anthony	Montoya	Western Area Power Administrat	Yes
99	John	Moraski	Baltimore Gas and Electric	No
100	Mary Ann	Morlan	Minnesota Power	No
101	Jeff	Mueller	Public Service Electorate	No
102	Crystal	Musselman	Proven Compliance Solutions	No
103	Gilbert	Neveu	Quebec Energy Board	Yes - Proxy for Jean-Paul Theoret
104	David	Nevius	NERC	Yes
105	Micheal	Nitido	Tucson Electric Power	No
106	Larry	Nordell	Montana Consumer Council	Yes
107	Julius	Pataky	B C Hydro	Yes
108	Brianna	Patterson	Ready Talk	No
109	Robert	Pence	Cal Energy	No
110	Kaylie	Peters	Lincoln Electric Sys	No
111	Ken	Peterson	NERC Board	No
112	Kenneth	Petroff	P S E G Nuclear	No
113	Cynthia	Pointer	N E R C	No
114	Maggie	Powell	Constellation Energy	No
115	David	Proebstel	Clallan P U D	No
116	Andy	Pusztai	American Transmission Co	No
117	Billie	Quantrell	Klickitat P U D	No
118	Stephen	Ralls	San Miguel Electric Co-Op	No
119	Harvey	Reed	NPCC	Yes
120	Mark	Robinson	S P P	No
121	Beth	Robinweiler	Puget Sound Energy	No
122	Rex	Roehl	Indeck Energy Svcs	No
123	Sarah	Rogers	F R C C	No
124	Steve	Rose	C W L P	No
125	Chris	Scanlon	Exelon	No
126	Chris	Schaeffer	Duke Energy	No
127	Dan	Schoenecker	MRO	No
128	Ed	Schwerdt	N P C C	No
129	Sandra	Shaffer	Pacific Corp	No
130	Kiriat	Shah	Ameren	No
131	Ken	Shortt	Pacific Corp	No
132	Barry	Skoras	P P L Electric Utilities	No
133	Robert	Smith	Arizona Public Service Co	No
134	Daniel	Soulier	The Regie	No
135	Bob	Stewart	Duke Energy	No
136	William	Taylor	Calpine	Yes
137	Clayton	Tewkfbury	Bridgeport Energy	No
138	Roy	Thilly	NERC Board	No
139	Bob	Thomas	Illinois Municiple Electric Co	No
140	David	Thorne	Pepco Holdings	No
141	Scott	Tomashefasky	Northern California Power	No
142	John	Twitty	City Utilities of Springfield	Yes
143	Ed	Tymofichuk	Manitoba Hydro	Yes
144	Lisa	Umeda	City Glendale	No
145	Patrick	VanBuskirk	Indiannapolis Power & Light	No
146	Claire	Warshaw	S M U D	No
147	Mark	Westendorf	Midwest I S O	No
148	Larry	Whanger	Dominion Resources	No
149	Jim	Willams	Western Interstate Energy Boar	No

150	Wanda	Williams	Selkirk Cogen	No
151	Byron	Williamson	Tacoma Power	No
152	Chris	Wilson	Southern Co	No
153	Steve	Wunderlich	Auburn Dale	No
154	Mike	Yealland	I E S O	No
156	Clay	Young	South Carolina Electric & Gas	No
155	Charles	Young	Southwest Power Pool	No
157	Jian	Zhang	Transalta	No
158	James	Ziebarth	Y W Electric Assoc	No

## Draft Agenda Member Representatives Committee

May 10, 2011 | 1:00–5:00 p.m. ET  
The Westin Arlington Gateway  
801 Glebe Road  
Arlington, VA  
703-717-6200

### **May 5, 2011 Informational Webinar — 1–3:00 p.m., ET**

- a. Preview of 2011 Summer Reliability Assessment
- b. Status of Geomagnetic Disturbance Task Force Activities
- c. Critical Infrastructure Protection Initiatives

### **May 10, 2011 MRC Meeting — 1:00–4:45 p.m. (Open)**

#### **Introductions and Chairman's Remarks**

#### **NERC Antitrust Compliance Guidelines and Public Meeting Notice**

#### **Consent Agenda — Approve**

##### **1. Minutes**

- April 13, 2011 conference call
- February 16, 2011 meeting

##### **2. Future Meetings**

#### **Regular Agenda<sup>1</sup>**

##### **3. Remarks by Gerry Cauley, NERC President and CEO**

##### **4. MRC Members to the Board of Trustees Nominating Committee**

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<sup>1</sup> Board Chairman John Q. Anderson has invited input from the committee sector representatives on specific agenda items (see attached).

- 5. Bulk Electric System Definition**
    - a. BES Definition SDT – Pete Heidrich
    - b. BES ROP Team – Carter Edge
    - c. BES/ALR Policy Issues Task Force – Bill Gallagher
  - 6. Analysis of Cold Weather Impacts on the Bulk Power System**
  - 7. Facility Ratings Alert Responses and Next Steps**
  - 8. Event Analysis Process Improvements**
  - 9. NERC Metrics**
    - a. Overview of Metrics Initiatives
    - b. System Reliability Performance Metrics
    - c. Reliability Dashboard Demonstration
    - d. Regional Delegation Agreement Metrics
  - 10. Comments by Observers**
  - 11. Items for August 2011 MRC Agenda**
  - 12. 2012 Business Plan and Budget**
- Information Only — No Discussion**
- 13. Update on Regulatory Matters\***

\*Background material included.



## Draft Agenda Board of Trustees

May 11, 2011 | 8 a.m.–12:00 p.m. ET  
The Westin Arlington Gateway  
801 Glebe Road  
Arlington, VA  
703-717-6200

### **Introductions and Chair's Remarks**

### **NERC Antitrust Compliance Guidelines and Public Meeting Notice**

### **Consent Agenda — Approve**

#### **1. Minutes**

- March 10, 2011 Conference Call
- February 17, 2011 Meeting

#### **2. Committee Membership Appointments and Changes (if applicable)**

- Standing Committee Membership Changes
- Standing Committee Charter Changes
  - Standards Committee Charter

#### **3. Future Meetings**

### **Regular Agenda**

#### **4. Possible Guest speaker**

#### **5. Possible Chairman and Commissioners**

#### **6. President's Report**

#### **7. Reliability Standards\***

- ROP Appendix 3B - SC Election Procedure — **Approve**
- ROP - Appendix 3D - Registered Ballot Body Criteria — **Approve**
- ReliabilityFirst Corporation Reliability Standards Development Procedure Version 3 – b — **Approve**

#### **8. Amendments to NPCC Bylaws – Approve**

9. **NPCC-WECC CEA Agreement – Approve (possible)**
10. **Update to NERC Membership Roster – Approve**
11. **Regulatory Update – Review**

**Standing Committee Reports (Agenda Item 12)\***

- [Compliance and Certification Committee](#)
- [Critical Infrastructure Protection Committee](#)
- [Member Representatives Committee](#)
- [Operating Committee](#)
- [Personnel Certification Governance Committee](#)
- [Planning Committee](#)
- [Standards Committee](#)
- [Electricity Sub-Sector Coordinating Council](#)

**Forum and Group Reports (Agenda Item 13)**

- [North American Energy Standards Board](#)
- [Regional Entity Management Group](#)
- [North American Transmission Forum](#)
- [North American Generator Forum](#)

**Board Committee Reports**

14. **Corporate Governance and Human Resources**
15. **Compliance**
16. **Finance and Audit**
  - a. Approve 2010 Audited Financial Statements
  - b. Accept Statement of Activities
  - c. Update on Draft 2012 Business Plan and Budget
  - d. Report to Board Regarding Review of Financial Aspects of Form 990 (No Board Action Required)
17. **Standards Oversight and Technology**

\*Background material included.

## Draft Agenda — Open Session Board of Trustees Compliance Committee

May 10, 2011 | 4:45-5:45 p.m.  
The Westin Arlington Gateway  
801 Glebe Road  
Arlington, VA  
703-717-6200

### **Introductions and Chair's Remarks**

### **NERC Antitrust Compliance Guidelines**

- 1. Overview of Meeting Objectives and Process\***
- 2. Consent Agenda\* — Approve**
  - a. Minutes — February 16, 2010
  - b. Future Meetings
- 3. NERC Staff Update\***
  - a. Compliance Operations
    - i. Risk-based Reliability Compliance Monitoring
    - ii. Top reliability Issues to inform compliance
    - iii. Abrupt changes in Registration – EOP-005 analysis 220 violations associated with
    - iv. Compliance Application Notices Update
  - b. Compliance Enforcement
    - i. Administrative Citation Process
    - ii. Mitigation
    - iii. Quarterly Stats
- 5. Other Matters**

\*Background material included.



NORTH AMERICAN ELECTRIC  
RELIABILITY CORPORATION

**Meeting Schedule**  
**May 10-11, 2011 — Arlington, Virginia**

**May 10**

7:30-8:15 a.m. Corporate Governance and Human Resources Committee – **CLOSED**

8:15-9:00 a.m. Corporate Governance and Human Resources Committee – **OPEN**

**15 Minute Break**

9:15-10:15 a.m. Standards Oversight and Technology Committee

**15 Minute Break**

10:30-11:00 a.m. Finance and Audit Committee – **CLOSED**

**15 Minute Break**

11:15 a.m.-Noon Finance and Audit Committee – **OPEN**

12:00 p.m. **Lunch**

1:00-4:45 p.m. Member Representatives Committee

4:45-5:45 p.m. Compliance Committee – **OPEN**

6:30 p.m. **Reception**

7:30 p.m. **Formal Sit Down Dinner**

**May 11**

6:45 a.m. Board of Trustees Breakfast

7:00–8:00 a.m. Board of Trustees Meeting - **CLOSED**

8:00 a.m.–Noon Board of Trustees Meeting

Dress is business casual for all meetings and the Reception/Dinner.

## Draft Minutes Member Representatives Committee

February 16, 2011 | 1–5:00 p.m. MT

Hyatt Regency Phoenix  
122 North 2<sup>nd</sup> Street  
Phoenix, Arizona 85004

Chairman Bill Gallagher called to order the North American Electric Reliability Corporation (NERC) Member Representatives Committee (MRC) meeting on February 16, 2011 at 1 p.m., local time. The meeting announcement, agenda, and list of attendees are attached as **(Exhibits A, B, and C)**, respectively.

### **NERC Antitrust Compliance Guidelines**

David Nevius, committee secretary, called attention to the NERC Antitrust Compliance Guidelines and the public meeting notice.

### **Introductions and Chairman's Remarks**

Chairman Gallagher declared a quorum present and announced the following proxies:

- Ajay Garg for Carmine Marcello – Federal/Provincial Utility
- Kathryn Mirr for William Taylor III – Merchant Electricity Generator
- Gilbert Neveu for Jean-Paul Théorêt – Canadian Provincial (non-voting)
- Sarah Rogers for Gordon Gillette – Regional Entity (non-voting) FRCC
- Del Smith for Robin Lunt – State Government

Mr. Gallagher also introduced the following new MRC members:

- Tom Burgess, director, FERC policy and compliance, FirstEnergy Corp. – Investor-Owned Utility
- John DiStasio, general manager and CEO, Sacramento Municipal Utility District – State/Municipal Utility
- Eric Baker, president and CEO, Wolverine Power Supply Cooperative – Cooperative Utility

- Lorne Midford, director, transmission system operations, Manitoba Hydro – Federal/Provincial Utility
- Kathryn Mirr, compliance and regulatory specialist, Sempra Global – Merchant Electricity Generator
- Jack Cashin, director of regulatory affairs, Electric Power Supply Association – Electricity Marketer
- Robin Lunt, assistant general counsel, National Association of Regulatory Utility Commissioners – State Government
- Gordon Gillette, president, Tampa Electric Company – Regional Entity Non-Voting (FRCC)
- Sue Ivey, vice president, transmission operations and planning, Exelon Corporation – Regional Entity Non-Voting (RFC)
- Ed Tymofichuk, vice president, transmission, Manitoba Hydro – Regional Entity Non-Voting (MRO)

Chairman Gallagher called attention to a letter to the MRC from John Q. Anderson, chairman, Board of Trustees, NERC, which requested policy input to the board on several issues. Mr. Gallagher stated there was a very good response and thanked those who submitted written input.

### **Minutes**

The MRC approved draft minutes of the November 3, 2010 meeting and the January 11, 2011 conference call. (**Exhibits D and E**).

### **Future Meetings**

The MRC approved February 22–23, 2012 in Phoenix, AZ as a future meeting date and location.

[Secretary’s Note: The MRC will be asked to approve at its May 10, 2011 meeting revised dates of February 8-9, 2012, along with a slate of meeting dates and locations through the end of 2013.]

### **Election of Trustees**

Tom Berry, chairman, Board of Trustees Nominating Committee, announced the candidates for new member election and re-election of NERC board members. Chairman Gallagher called for a vote of the MRC on the following four nominees for election to the NERC Board of Trustees, Class of 2014 (three-year terms):

- Paul Barber
- Janice Case



- Fred Gorbet
- Roy Thilly

Chairman Gallagher received 27 confirmed votes and congratulated the new and returning members of the NERC Board of Trustees.

**Comments by Outgoing MRC Chairman Ed Tymofichuk**

Ed Tymofichuk, vice president, transmission, Manitoba Hydro and MRC outgoing chairman, stated he was pleased with the direction the MRC has taken, reviewed some of the accomplishments to date, and thanked everyone for their support.

**Remarks by Gerry Cauley – president and CEO, NERC**

Gerry Cauley, president and CEO, NERC, commented that the FERC Reliability Summit was a very important event for NERC, adding that the focus of the Summit was on reliability priorities and delivering reliability value. He stated it would be beneficial to have similar meetings on an annual basis.

Mr. Cauley also indicated he is enthusiastic about NERC's Vision and the path NERC has taken. NERC is in the process of developing strategic goals to lay out where NERC wants to be at the end of the next three to five years. This is currently in the board package for review at the board meeting.

Mr. Cauley discussed a bold concept of a trial compliance period when a new standard is released. He noted that NERC's actions as the ERO may be driving *compliance* risk management more than *reliability* risk management and proposed, on a pilot basis, a process for putting a new standard into effect on a trial basis with audit and feedback coming from compliance. This would also help the front-end learning stage when a new standard is adopted. Mr. Cauley believes it would help the caseload if we could do the learning under a test environment rather than in an enforcement environment, and welcomed feedback on this concept.

Mr. Cauley stated that NERC has made good progress during 2010 crystallizing the direction and focus in the cyber security area. He added, however, that the greatest risk for the long-term success to the ERO is the ability to produce an adequate, technically sufficient body of Standards.

Finally, Mr. Cauley discussed significant concerns with the recent cold snap in Texas, Arizona, New Mexico and other parts of the southwest. NERC will do a review of the issues, causes, and why it happened and views this as a challenge to the ERO. Mr. Cauley and others from FERC participated in a hearing held by the U.S. Senate Committee on Energy and Natural Resources headed by Senator Bingaman on Monday, February 21, 2011.

### **Welcome to Phoenix**

Dave Areghini, associate general manager, Salt River Project and the WECC regional entity representative to the MRC welcomed everyone to Phoenix, reviewed some history on Phoenix, and expressed his gratitude for the invitation to the NERC meeting.

### **Bulk Electric System Definition — Policy Issues and Questions**

Herb Schrayshuen, vice president and director, standards, NERC, presented the status and action plan for developing a revised definition of the Bulk Electric System (BES). Mr. Schrayshuen stated on November 18, 2010 FERC issued Order 743 and directed NERC to revise the definition of BES so that the definition encompasses all Elements and Facilities necessary for the reliable operation and planning of the interconnected bulk power system. Additional specificity will reduce ambiguity and establish consistency across all Regions in distinguishing between BES and non-BES Elements and Facilities.

A proposed Standard Authorization Request (SAR), a proposed revision to the definition of BES, and some concepts proposed for a BES Definition Exception Process were all posted for an extended 30-day informal comment period: December 17, 2010 – January 21, 2011 as part of Standards Project 2010-17.

The MRC members, in addition to providing written input on the policy aspects of this issue, discussed the issue at length.

Gerry Cauley indicated that the Commissioners view this as a different form of order, and emphasized the importance of coming back with sufficient responsive answer, showing the Commission what the industry can do. He added that this was not a traditional technical team issue and that we must develop a consistent methodology across North America. He urged the MRC to take advantage of this opportunity to exhibit policy-level leadership.

[Secretary's Note: Following the meeting, MRC chairman, Bill Gallagher, prepared a list of MRC members to serve on a special MRC task force to address the policy issues and questions associated with the BES definition, exclusion criteria, exemption process, as well as the definition of Adequate Level of Reliability.]

### **Follow-up from February 8, 2011 FERC Technical Conference — Priorities for Addressing Risks to Reliability**

Gerry Cauley touched briefly again on the positive nature of the FERC Technical Conference and its focus on policy issues and priorities for addressing risks to the reliability of the Bulk Power System. Mr. Cauley also brought attention to the NERC President's Top Priority Issues for Bulk Power System Reliability – January 7, 2011, which was included in the MRC agenda package.

John A. Anderson, president and CEO, Electricity Consumers Resource Council and MRC member, who attended the FERC Technical Conference, observed that there was very good communication between FERC and NERC and that such conferences provided an excellent way of developing and building on the communication between the two organizations. He believes the NERC Standards Committee has done a tremendous job in developing the prioritization tool and encouraged the FERC staff to give consideration on that tool.

Ed Tymofichuk, vice president, transmission, Manitoba Hydro and MRC member, stated that the forum was a tremendous opportunity to allow people to talk openly and plainly on the issues and build common understandings, whether about cost of reliability, the standards process, building trust and respect, and building on good communication and collaboration.

Mr. Cauley noted that the priority list is a working document and that he would welcome comments and suggestions. As far as what is next, Mr. Cauley stated the standards prioritization process considered these priorities in the evaluation of standards priorities, and Mike Moon, director, compliance operations, NERC, will review the list in terms of what standards will be looked at next year in the compliance auditing and monitoring program. Mr. Cauley believes the priority list is good guidance to all NERC's different program areas on what to look at most.

#### **Lessons Learned from Recent Alerts and Improvements to Alerts Process**

Gerry Adamski, director of situation awareness and training, NERC, gave a presentation on the Alerts Process and Improvement Opportunities. Mr. Adamski stated NERC recognizes while we undergo our internal mapping processes we have identified the development process for Alerts as one of the highest priority activities NERC has to focus on. NERC will need consistency in delivery of the Alerts moving forward. The most significant of these is to establish the mechanism for systematic industry engagement in the review and comment on Alerts prior to issuance. Implementation of this process will be late first quarter 2011 with an associated Rules of Procedure modification expected by year-end. Additional improvements under consideration include numerous changes to the NERC Alerts System to improve the registered user and administrator experience, or alternately, development of a business case to replace the existing system. After much discussion, the consensus was that stakeholder input would make the Alert process successful.

Tom Galloway, senior vice president and chief reliability officer, NERC, presented on the Facility Ratings Alert. Mr. Galloway discussed that the Alert was issued October 10, 2010; NERC held the Facility Ratings Alert Webinars on October 27 and November 28, 2010, and a revised Alert was issued on November 30, 2010. He reported that NERC needs to be more systematic with outward communications in terms of status and response to the Alert and what lessons learned might be shared in real-time.

Mr. Galloway stated NERC is moving toward routine communications and anticipates having outgoing communications to the industry on a quarterly basis starting second quarter 2011.

Carol Dodson, senior vice president, asset management services, Baltimore Gas & Electric, presented on Baltimore Gas & Electric's experience using LiDAR to supplement its FAC-009 compliance program to confirm transmission facility ratings.

### **Draft Response to FERC Order on Three-Year ERO Performance Assessment**

Dave Nevius noted that NERC posted the February 9, 2011 draft of the informational filing required by the Commission's September 16, 2010 Order, which was issued in response to NERC's Three-Year ERO Performance Assessment filed in July, 2009.

Mr. Nevius noted that the February 9 draft is still a work in progress. He added that Appendix A, a progress report on the Specific NERC Actions cited in NERC's 2009 filing, will be included in the next draft. The board will meet by conference call in March to approve the completed informational filing, which will then be filed with the Commission by March 16, 2011. MRC members were invited to offer written comments or suggestions on the preliminary draft of the NERC informational filing.

### **Overview of NERC Reliability Metrics Initiatives**

Mr. Nevius and Mark Lauby, director of reliability assessments and performance analysis, NERC, gave an overview of NERC Reliability Metrics Initiatives. Mr. Nevius discussed that NERC's several metrics initiatives, which are being developed in conjunction with each other, can be grouped into three categories. First, NERC is working with its Operating and Planning Committees and their subgroups to develop, calculate, and assess several types of bulk power system-level reliability indicators, which will comprise multiple dimensions of system-level reliability indicators to enable industry to identify and understand reliability issues and trends in the areas of system design, planning, operating, and maintenance. Second, NERC is working with its Compliance and Certification Committee to develop a parametric suite of measures providing insight into compliance process efficiency such that areas for improvement may be identified and actions taken to address them. Third, NERC is working in collaboration with the Regional Entities to measure the effectiveness of all the programs that are the responsibility of the ERO Enterprise, including the functions delegated to Regional Entities.

Mr. Nevius stated additional material on metrics would be available for the May 2011 MRC meeting, particularly on a specific set of metrics for inclusion in the Regional Delegations Agreements.

### **ERO Enterprise Strategic Direction**

Gerry Cauley reviewed the ERO Enterprise Strategic Direction and stated the NERC board, NERC management, and Regional Entities are working on strategic goals and

objectives for the ERO Enterprise for 2011–2014. Mr. Cauley stated the board would discuss the goals at their meeting on Thursday, February 17. MRC written input for discussion of the goals and objectives was received and will help inform the board's discussion.

**Items for May 2011 MRC Agenda**

Chairman Gallagher invited MRC members to volunteer to present on what they are doing in their own organizations to promote a Culture of Reliability Excellence. Mr. Gallagher also invited suggestions for topics to be presented on the informational webinar that will precede the MRC meeting.

**Update on Regulatory Matters**

Chairman Gallagher noted that the agenda contained an Update on Regulatory Matters. No further discussion occurred.

**Adjournment**

There being no further business, the meeting was terminated at 5:00 p.m.

Submitted by,



David R. Nevius  
Secretary

**From:** [Elizabeth Merlucci](#)  
**To:** [Elizabeth Merlucci](#)  
**Subject:** ANNOUNCEMENT: Member Representatives Committee (MRC) and Board of Trustees Meeting (BOT) - February 16-17, 2011  
**Date:** Thursday, December 16, 2010 9:52:58 AM  
**Importance:** High

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## Meeting Announcement Member Representatives Committee (MRC) and Board of Trustees (BOT)

February 16–17, 2011 | Phoenix, AZ

Register online today: <https://www.nerc.net/nercsurvey/Survey.aspx?s=5968e45f4f674f70bc975116ba01fb83&ForceNew=true>

Meeting Details: <http://www.nerc.net/meetings/search/details.asp?id=2999>

*When making your hotel reservation, please be sure to mention "NERC" to get the preferred rate and ensure your reservation is credited to the NERC room block. The hotel will charge NERC a penalty if the total rooms blocked for this event are not picked up. Also, if you use a travel agency for your travel plans, please make sure the agency mentions NERC. For more information or assistance, please contact Elizabeth Merlucci, Administrative Assistant, at [elizabeth.merlucci@nerc.net](mailto:elizabeth.merlucci@nerc.net) or at (609) 524-7038.*

North American Electric Reliability Corporation  
116-390 Village Blvd.  
Princeton, NJ 08540  
609.452.8060 | [www.nerc.com](http://www.nerc.com)



## Agenda Member Representatives Committee

February 16, 2011 | 1–5:00 p.m. MT

Hyatt Regency Phoenix  
122 N Second St.  
Phoenix, AZ  
602-252-1234

**New Member Orientation Session — 9:15–10:15 a.m. (Open)**

**MRC Closed Session — 12:00–12:30 p.m. (Voting Members Only)**

**Regular MRC Meeting — 1:00–5:00 p.m. (Open)**

**Introductions and Incoming Chairman's Remarks**

**NERC Antitrust Compliance Guidelines and Public Meeting Notice**

**Consent Agenda — Approve**

**1. Minutes**

- [January 11, 2011 Conference Call](#)
- [November 3, 2010 Meeting](#)

**2. Future Meetings**

**Regular Agenda<sup>1</sup>**

**3. Election of Trustees**

**4. Comments by Outgoing MRC Chairman**

**5. Remarks by Gerry Cauley, NERC President and CEO**

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<sup>1</sup> Board Chairman John Q. Anderson has invited input from the committee sector representatives on specific agenda items (see attached).

- 6. Welcome to Phoenix**
- 7. Bulk Electric System Definition — Policy Issues and Questions**
- 8. Follow up from February 8 FERC Technical Conference — Priorities for Addressing Risks to Reliability**
- 9. Lessons Learned from Recent Alerts and Improvements to Alerts Process**
- 10. Draft Response to FERC Order on Three-Year ERO Performance Assessment**
- 11. Overview of NERC Reliability Metrics Initiatives**
- 12. ERO Enterprise Strategic Direction**
- 13. Comments by Observers**
- 14. Items for May 2011 MRC Agenda**
  - a. MRC Volunteer to Speak on “Culture of Reliability Excellence”
  - b. Suggestions for Informational Webinar Presentations

**Information Only — No Discussion**

- 15. Update on Regulatory Matters\***

\*Background material included.

**List of Attendees  
Member Representatives Committee Meeting  
Phoenix, AZ  
February 16, 2010**

<b>Member Representatives Committee</b>	
Chairman	Bill Gallagher
Vice Chairman	Scott Helyer
Investor-Owned Utility	Carol Chinn
Investor-Owned Utility	Thomas Burgess
State/Municipal Utility	Timothy Arlt
State/Municipal Utility	John DiStasio
Cooperative Utility	Michael Smith
Cooperative Utility	Eric Baker
Federal/Provincial Utility	Julius Pataky
Federal/Provincial Utility	Anthony Montoya
Federal/Provincial Utility	Lorne Midford
Federal/Provincial Utility	<del>Carmin Marcello</del> <b>(PROXY: Ajay Garg)</b>
Transmission Dependent Utility	John Twitty
Transmission Dependent Utility	Terry Huval
Merchant Electricity Generator	Kathryn Mirr
Merchant Electricity Generator	<del>William Taylor III</del> <b>(PROXY: Kathryn Mirr)</b>
Electricity Marketer	Roy True
Electricity Marketer	Jack Cashin
Large End-Use Electricity Customer	Michelle D'Antuono
Large End-Use Electricity Customer	John Anderson
Small End-Use Electricity Customer	Lawrence Nordell
Small End-Use Electricity Customer	Charles Acquard
ISO/RTO	Paul Murphy
ISO/RTO	Terry Boston
Regional Entity (Voting)	Stacy Dochoda (SPP)
Regional Entity (Voting)	Craven Crowell (TRE)
State Government	<del>Thomas Dvorsky</del>
State Government	<del>Robin Lunt</del> <b>(PROXY: Del Smith)</b>
Canadian Provincial	Jean-Paul Théorêt <b>(PROXY: Gilbert Neveu)</b>
Canadian Federal	Amitabha Gangopadhyay
U.S. – Federal	<del>Pat Hoffman</del>
U.S. – Federal	Joseph McClelland
Regional Entity	<del>Gorden Gillette (FRCC)</del> <b>(PROXY: Sarah Rogers)</b>

Regional Entity	Ed Tymofichuk (MRO)
Regional Entity	Harvey Reed (NPCC)
Regional Entity	Susan Ivey (RFC)
Regional Entity	Maureen Borkowski (SERC)
Regional Entity	David Areghini (WECC)
Secretary	Dave Nevius

<b>Board of Trustees</b>	
Chairman	John Q. Anderson
Vice chair	Bruce Scherr
Member	Vicky Bailey
Member	Paul Barber
Member	Thomas Berry
Member	Janice Case
Member	Gerry Cauley
Member	Fred Gorbet
Member	Jim Goodrich
Member	David Goulding
Member	Ken Peterson
Member	Jan Shori
Member	Roy Thilly

<b>Regional Managers</b>	
MRO	Dan Skaar
NPCC	Edward A. Schwerdt
Texas Reliability Entity	Larry Grimm
WECC	Mark Maher
FRCC	Sarah Rogers – <b>MRC Proxy</b>
SERC	Scott Henry
ReliabilityFirst	Tim Gallagher

<b>Guests</b>	
APPA	Alan Mosher
SPP	Alice Wright
NRECA	Barry Lawson
Midwest ISO	Bill Phillips
NERC	Bob Cummings
Southern Company	Bob Schaffeld
NERC	Brian Harrell

PRPA/LPPC	Brian Moeck
Colorado Springs Utilities	Bruce McCormick
Baltimore Gas & Electric	Carol Dodson
SERC	Carter B. Edge
Southwest Power Pool	Charles Yeung
Georgia Systems Operations Corporation	Clay Smith
WECC	Constance White
SMUD	Craig Cameron
Northeast Utility	Dave Boguslawski
NERC	David Cook
EEI	David Dworzak
NRECA	David Mohre
AZ Corporation Commission	Del Smith
NERC	David Taylor
PSE&G	Don Holdsworth
IESO Ontario	Don Tench
Entergy	Ed Davis
Edison Mission Energy	Ellen Oswald
NERC	Eleanor Crouch
NERC	Gerry Adamski
BPA	Hardev Juj
NERC	Herb Schrayshuen
Dayton Power & Light	Hertzel Shamash
NERC	Holly Hawkins
Natural Resources Canada	Ivan Harvie
NERC	Janet Sena
ReliabilityFirst	Jeff Mitchell
PSE&G	Jeff Mueller
NPCC	Jennifer Budd Matiello
NEB	Jim Davidson
Wisconsin Electric	Jim Keller
FERC	Jim Pederson
WIEB/WIRAB	Jim Williams
NERC	Joel de Jesus
FERC	Jon First
CPS Energy	Jose Escamilla
SPP	F. John Meyer
SRP	Kelly Barr

NERC	Kimberly Mielcarek
FRCC	Linda Campbell
NERC	Lynn Constantini
NERC	Liz Merlucci
Dominion	Lou Oberski
Constellation Energy	Maggy Powell
Competitive Power Ventures	Mark Bennett
WECC	Mark Maher
NERC	Mark Lauby
SPP	Michael Desselle
Dominion	Michael Gildea
MRO	Miggie Crambilt
ITC	Mike Moltane
NERC	Mike Moon
ATC	Mike Rowe
NERC	Mike Walker
Sacramento Municipal Utility District	Michael Gianunzio
Oncor Electric Delivery	Michael Quinn
National Grid	Nabil Hitti
Southern California Edison	Neil Shockey
Southern California Edison	Patrick Farrell
Canadian Electricity Association	Pierre Guimond
NERC	Rebecca Michael
NERC	Ric Cameron
CPS Energy	Richard Castrejana
FERC	Roger Morie
Duke Energy	Sam Holeman
MRO	Sara Patrick
Exelon	Steve Naumann
NERC-consultant	Stuart Brindley
Midwest ISO	Terry Bilke
SC Public Service	Terry Blackwell
NERC	Tina McClellan
AZ Corporation Commission	Toby Little
PJM	Tom Bowe
NERC	Tom Galloway

## Minutes Member Representatives Committee

November 3, 2010 | 12–5:00 p.m.  
Grand Hyatt Atlanta  
3300 Peachtree Street, Northeast  
Atlanta, GA  
404-237-1234

Chairman Ed Tymofichuk called to order the information portion of the North American Electric Reliability Corporation (NERC) Member Representatives Committee (MRC) meeting on November 3, 2010 at 12 p.m., local time. The meeting announcement, agenda, and list of attendees are attached as **Exhibits A, B, and C**, respectively. As normal, no phone-ins were prearranged.

### **NERC Antitrust Compliance Guidelines**

David Nevius, committee secretary, called attention to the NERC Antitrust Compliance Guidelines and the public meeting notice.

### **Information Session**

Mark Lauby, director of reliability assessment and performance analysis, presented information status reports on the following reliability assessment and performance analysis activities:

- Preview 2010/2011 Winter Reliability Assessment
- Risk Severity Tools Update
- Update on Integration of Variable Generation Task Force Activities

Jim Matthews, president of the U.S. National Committee of IEC and incoming vice president of the IEC Standardization Management Board, described the IEC's standards development and conformity assessment programs and discussed why NERC and its members should be aware of IEC standards.

Copies of all presentations are posted on NERC's Web Site at <http://www.nerc.com/filez/mrcmin.html>.

### **Introductions and Chairman's Remarks**

Chairman Tymofichuk called to order the regular meeting of the MRC at 1 p.m., local time and declared a quorum present. Chairman Tymofichuk welcomed and introduced guests,



Commissioner Cheryl LaFleur, FERC, and William Ball, executive vice president and chief transmission officer, Southern Company.

Chairman Tymofichuk then announced the following proxies:

- Barry Lawson for John Prescott – Cooperative Utility Sector
- Gregory Ford for Michael Smith – Cooperative Utility Sector
- Allen Mosher for Tim Arlt – State/Municipal Sector
- Ajay Garg for Carmine Marcello – Federal/Provincial Sector
- Chris Hajovsky for Trent Carlson – Electricity Marketer Sector
- Sarah Rogers for John Giddens – Regional Entity
- Gilbert Neveu for Jean Paul Théorêt – Canadian Provincial

Mr. Tymofichuk also introduced new MRC members Craven Crowell, chairman, Texas Reliability Entity (TRE) Board – Regional Entity Non-Voting, and Maureen Borkowski, president and chief executive officer, Ameren Transmission Company – Regional Entity Non-Voting (SERC).

Chairman Tymofichuk then called attention to the letter to the MRC from John Q. Anderson, chairman, NERC Board of Trustees, which requested policy input to the board on several issues. There was a very good response again and Chairman Tymofichuk thanked those who submitted written responses.

### **Minutes**

The MRC approved draft minutes of the August 4, 2010 meeting and the October 4, 2010 conference call. (**Exhibits D and E**).

### **Future Meetings**

The MRC approved the November 2–3, 2011 in Atlanta, GA as a future meeting date and location.

### **Welcome to Atlanta – William Ball, senior vice president, transmission planning and operations, Southern Company Services**

William Ball, senior vice president, transmission planning and operations, Southern Company Services expressed his gratitude on the invitation to the NERC meeting. Mr. Ball reviewed some information on the IGCC Project in Mississippi, discussed activities in the area, and welcomed everyone to Atlanta.

### **Remarks by Gerry Cauley – president and CEO, NERC**

Gerry Cauley, president and CEO, NERC, also welcomed everyone to Atlanta and stated that the last MRC meeting was one of the most constructive and interesting dialogues we have held at an MRC meeting in some time.

Mr. Cauley noted that NERC is starting to see some improvement in Standards, that FERC approved the procedure that was submitted in June regarding the opportunity to expedite the

standards process and those changes are in the process of being implemented. Mr. Cauley stated the Underfrequency Load Shedding Standard will be submitted to the NERC board on Thursday, November 4, 2010, which he considers a major accomplishment.

Mr. Cauley believes that one of the more difficult topics on the agenda is responding to FERC directive regarding a process to deal with Commission standards directives where the industry ballot does not succeed in approving a proposed standard. He indicated he is hopeful that the language in the order is clarifying and added that discussions with FERC and staff indicate their intent is not to tell the industry what standards have to be. Rather, he believes NERC can work with FERC to make sure mechanisms are in place for setting objectives, determining what problems to solve, and how to structure the vetting of a standard before final directives are issued to ensure NERC has all the input.

In addition to Standards, Mr. Cauley addressed another area of concern in Cyber Security and Critical Infrastructure. NERC is making progress and noted the Electricity Sub-Sector Coordinating Council Critical Infrastructure Strategic Roadmap, will go before the board on November 4, 2010. The Roadmap sets a framework regarding what NERC can do and what initiatives can be taken to deal with complex cyber attacks, multi-prong physical attacks, and geomagnetic storms and what technical initiatives can be taken to make headway in those areas. Mr. Cauley believes it is important to have that plan ahead of NERC so a coherent story can be told about what is being done to improve the resilience of the bulk power system.

Mr. Cauley also noted regarding the CIP-002 standard that he is hopeful that the ballot process will proceed in a positive manner so that NERC will obtain approval and closure on this standard. He indicated there is a new item in the CIP area that has been challenged by Congress to deliver Smart Grid interoperability standards to FERC. He indicated it is apparent in discussions that NERC's trying to piecemeal security of an integrated electric system and NERC's going to be challenged on that. Mr. Cauley urged follow up discussions on whether NERC will be better off to work with NIST to develop a more comprehensive set of guidelines on security for the electric system instead of treating Smart Grid as one issue and bulk power security as another.

Finally, Mr. Cauley discussed alerts and what plans may work to deal with the issue. He believes the solution is a sustainable program that recognizes the need to address some of the issues that come up. Mr. Cauley stated that he is focused on the sustainable approach to deal with this issue on an ongoing basis to make sure NERC does not get behind the curve.

### **MRC Officer Elections**

Chairman Tymofichuk announced the nominations of Bill Gallagher, special projects chief, Transmission Access Policy Study Group, for chairman and Scott Helyer, vice president transmission, Tenaska, Inc., for vice chairman of the MRC for 2011. Chairman Tymofichuk then called for a vote; none were opposed. Mr. Gallagher and Mr. Helyer will assume their newly appointed positions at the February 2011 MRC meeting in Phoenix, AZ.

### **Status of MRC Sector Nominations**

Chairman Tymofichuk announced that sector nominations will close on November 12, 2010. At this time there are still openings in Sector 6, Merchant Electricity Generator, Sector 7, Electricity Marketer, and Sector 12, State Government. It was also noted that this will be Gayle Mayo's, and Nabil Hitti's last meeting; Chairman Tymofichuk thanked both of them for their time and dedication to the MRC.

### **Culture of Reliability Excellence**

Chairman Tymofichuk introduced the four panel members for the discussion of the Culture of Reliability Excellence:

- Terry Huval, MRC member and director, Lafayette Utilities Systems, TDU Sector
- Greg Ford, CEO of Georgia Systems Operations Corporation, representing MRC member Mike Smith, Cooperative Sector
- Paul Murphy, MRC member and president and CEO, Independent Electric System Operator – Ontario, ISO/RTO Sector
- Billy Ball, former chairman of the MRC and currently executive vice president and chief transmission officer of the Southern Company, IOU Sector

Each of the panel members gave their opening remarks and offered their perspectives on what their organization is doing to promote a "Culture of Reliability Excellence," the successes they have had, the obstacles that they have encountered, and what NERC could do to help. Following their presentations, Chairman Tymofichuk opened the floor for questions and comments from other committee members.

The presentations and Q&A that followed addressed some of the differences between a culture of reliability compliance and a culture of reliability excellence, and identified some of the characteristics, behaviors, and practices that exemplify a culture of reliability excellence. Among these were:

- **Commitment to reliability** — Must stretch throughout the organization, from the Board of Trustees down. It should show up in the organization's vision, mission, and values as found in most Corporate Strategic Plans, and be continually reinforced through internal and external communications and by way of corporate performance measures used to drive and reward performance. The commitment cannot only be local to the organization, but also exhibited throughout the interconnection.
- **Depth of Knowledge Regarding Reliability** — Educate employees on what needs to be done as well as why it needs to be done; developed and displayed through organizations like NERC through commitment to participate in the development of reliability standards. Helps prepare operators to respond in situations that have not been examined or encountered previously.
- **Transparency** — A real belief in reliability means there is no need to hide things, but to share both good and bad experiences so others can benefit, which is the mark of a "learning organization." Employees need to know they are working on important things; opportunity to reinforce that reliability is one of those really important things.

- **Empowerment of Employees** — Employees should be independent and empowered to make decisions without feeling there is undue influence on them or fear of retribution. A culture of reliability excellence means, simply, doing the right thing.
- **Foundations of Corporate Culture Lead to a Culture of Reliability Excellence** — Must be understood from the board room down to the boiler room before you can have a culture of reliability excellence or a culture of any sort of excellence. Maintaining a balance of high reliability, low cost, and high customer satisfaction will result in constructive regulation that allows the organization to continue to have a healthy capital program, appropriate amount of O&M spending, which gets back to being able to provide high reliability balanced with low prices and high customer satisfaction. A culture of reliability excellence really reflects on the broader culture of whatever organization you are a part of.
- **Analogy to Safety** — Just as no job is so important as to jeopardize the safety of an employee or the public, no job is so important as to jeopardize the reliability of the bulk power system. The public is very interested in having reliable power and it is our responsibility to ensure that it happens. Encourage employees to tell you what they are concerned about and then those issues can be addressed proactively. When something does go wrong you have a full fledged investigation on what went wrong and what can be done to keep this from happening again in the future.
- **Promoting a Culture of Reliability Excellence** — Has to start at the top. Helps to develop direction for strategy in maintaining high reliability. Training programs used to ensure awareness of reliability standards and the need to meet those standards. Establish cross-functional teams to make sure the standards are being put at the highest priority. Invite upper management to hear results of peer reviews. Stay active to help develop the standards and promote a culture of reliability excellence internally, within a particular industry sector, and throughout the industry in general. Recognize employees for ideas and actions that promote culture of reliability excellence. Very important for leadership to make a big deal about reliability.
- **Reliability is More Than Just Keeping the Lights On** — Gives short shrift to the importance of the industry by making it sound like keeping the lights on is a matter of comfort and convenience. It is a matter of protecting public health and safety; it is a matter of protecting the economic prosperity of a nation, and it is a matter of protecting national security.
- **Address the Small Things to Avoid Big Problems** — If you operate successful safety programs and you have a lot of small accidents and you do not do enough about it at some point you can have a very serious accident. Look for what it takes to resolve the reliability issues today and then you have the planning and processes in place to not let other priorities take the place of ensuring that you have a reliable system.
- **Communicate Importance of Reliability** — Important to communicate the importance of reliability and safety from the standpoint of maintaining infrastructure.
- **Culture of Compliance Versus Culture of Reliability** — Recognize that not all standards are of equal impact on or importance to reliability. Perform reliability risk

assessments to determine where to put our greatest effort. Look at it from the perspective of what is the risk to reliability of the interconnected system rather than the risk of non-compliance.

### **Critical Infrastructure Protection (CIP Activities)**

Critical Infrastructure Department Update — Mark Weatherford, vice president and chief security officer, NERC, stated that the last couple months have been focused on the Electricity Sub-Sector Coordinating Council (ESCC) Critical Infrastructure Strategic Roadmap. The purpose of the ESCC Roadmap is to put plans in place for High Impact/Low Frequency events – coordinated cyber attack, coordinated physical attack, and geo-magnetic disturbances.

Mr. Weatherford noted NERC has completed the CIP-002 sufficiency reviews and has been following up these reviews with workshops and on-site presentations. He noted that we released our first industry alert on Stuxnet at the end of July and followed that up in September with the actual recommendations for industry. NERC also put out the Aurora recommendation and is continuing to field questions and put together a series of Webinars and a workshop for the industry. Mr. Weatherford also indicated that in October, NERC participated in the national level DHS sponsored CyberStorm III exercise, which involved a number of industries, government, and states.

Critical Infrastructure Strategic Roadmap and Coordinated Action Plan — Stuart Brindley, NERC consultant for the Electricity Sub-Sector Coordinating Council (ESCC), presented on the Critical Infrastructure Strategic Roadmap and Coordinated Action Plan. He specifically noted some changes made since the last versions of the documents were reviewed with the MRC.

Enhanced Critical Infrastructure Protection (ECIP) Program Sponsored by DHS — Steven B. Nicholas, DHS Office of Infrastructure Protection, Louis Dabdoub and Chris Peters, Entergy and Stephany Peyton, Argonne National Labs presented on the Enhanced Critical Infrastructure (ECIP) Program sponsored by U.S. Department of Homeland Security (DHS). The Program uses a methodology for assessing infrastructure risk and resilience to a variety of natural and man-made hazards, including statistical and data-mining procedures to analyze and display the data collected in easy-to-use “dashboards.” The ECIP Program is provided at no cost to organizations with critical infrastructures.

### **Standards and Standards Process Issues**

Order Denying Rehearing of March 18, 2010 Order Directing Changes in NERC’s Standards Development Procedure — David Cook, senior vice president and general counsel, NERC, discussed NERC’s response to the Order Denying Rehearing of the March 18 and September 16, 2010 Orders directing changes in NERC’s Standards. Mr. Cook stated that the ballot body cannot keep NERC from being responsive to a FERC directive. NERC’s compliance filing is due to FERC on December 13, 2010.

Mr. Cook then reviewed Alternatives A and B, as presented in the MRC agenda, and Alternative C, which represented a combination of A and B. Mr. Cook reported that after receiving industry comment the board adopted a proposed set of changes to the standards

process. NERC did not file changes with FERC for a variety of reasons. FERC extended the deadline and scheduled the July 6<sup>th</sup> technical conference. Because FERC denied rehearing of the March 18 and September 16 Orders NERC will need to complete a compliance filing on December 13. NERC posted for comment the same set of changes that the board approved in June, Alternative A, and also included Alternative B based on other discussions. Mr. Cook explained the principal difference is that Alternative A would call for a standard to be put back into the ballot body for one more vote and drops the affirmative approval requirement from two-thirds to 60 percent. If it passes at the 60 percent level the board would consider it, if not the board would file a report with FERC explaining the circumstances. In Alternative B, the board would ask the Standards Committee or NERC management to prepare a draft, post it for comment, and then the board would have the authority to take action and file it with FERC with recommendations. NERC staff consulted further with representatives from the trade associations to review and discuss the issue and out of that discussion a possible further option which combines Alternative A and B evolved. Alternative C would retain the feature that the board would refer it back to the industry for another vote under the instruction that it had not dealt with the directive, and that the approval percentage was being dropped to 60 percent. If that didn't produce an approved standard then the board could exercise its authority to have a draft standard prepared, posted, and take action on that standard. Mr. Cook stated combining the Alternatives will still place an emphasis on the standards development process. There is a mechanism for the board to make the final decision. It is more likely that the stakeholders will take advantage of the opportunity to shape the standard in a way they would like to shape it that still complies within the directive. The comment period will run through December 2 and the board will need to make a decision on what to file prior to December 13, 2010.

Proposal for Technology and Standards Oversight Committee — David Cook stated during the August meetings in Toronto there was considerable discussion with the stakeholders about the board's interest in pursuing an oversight role over the standards process. This was discussed by the Corporate Governance and Human Resources Committee (CGHR) during its October 27, 2010 conference call and is prepared to recommend a change to the mandate of the Technology Committee to expand it to include standards oversight.

NERC Three-Year Reliability Standards Development Plan — Herb Schrayshuen, vice president and director of standards, NERC, gave a presentation and reviewed the open issues of the NERC Three-Year Reliability Standards Development Plan, which is on the Board agenda for approval at the board meeting on November 4.

Changes to Reliability Standards Development Procedure Approved by FERC and NERC Transition Plan — Mr. Schrayshuen also provided a brief presentation on the changes to the Reliability Standards Development Procedure that were previously approved by NERC and FERC.

### **Response to FERC Order on Three-Year ERO Performance Assessment**

Dave Nevius, committee secretary, explained that on September 16, 2010, FERC issued its order on the Three-Year ERO Performance Assessment, which NERC filed with FERC in July 2009. The order included a number of directives that NERC is required to respond to by March 16, 2011.



Mr. Nevius outlined NERC's planned approach and timeline for responding to the directives in the FERC order. He stated that we are in the process of putting together a first draft of a response to go out for comment and possibly arrange a Webinar during the January/February 2011 timeframe.

### **Reliability Summit Issues**

Chairman Tymofichuk indicated this item is meant to discuss ideas and topics for the Reliability Summit. Due to time constraints this item will be rescheduled for discussion at a later date. No further discussion occurred.

### **Alerts and Lessons Learned**

Gerry Adamski, director of situation awareness and training, NERC, briefly discussed opportunities for improving the alerts system. Mr. Adamski also stated that to date, 16 lessons learned have been posted in the Resource Center of the NERC Web Site. These lessons learned have been developed to provide the industry with the details and possible corrective actions on a timely basis for commonly seen or widely-applicable issues found during the course of event analyses.

### **Frequency Response Initiative**

Bob Cummings, director of system analysis and reliability initiatives, NERC, presented and updated the MRC on the status of the Frequency Response Initiative.

### **Update on Regulatory Matters**

Chairman Tymofichuk noted that the agenda contained an Update on Regulatory Matters. No further discussion occurred.

### **Adjournment**

There being no further business, the meeting was terminated at 5:00 p.m.

Submitted by,



David R. Nevius  
Secretary



## Conference Call Minutes Member Representatives Committee

January 11, 2011 | 11 a.m.–Noon  
Dial In: 800-913-1647

Chairman Ed Tymofichuk convened a duly-noticed open meeting by conference call of the North American Electric Reliability Corporation's Member Representatives Committee (MRC) on January 11, 2011 at 11 a.m. EST. The meeting announcement, agenda, and list of attendees are attached as **Exhibits A, B, and C**, respectively. No roll call was taken and no quorum was required.

### **NERC Antitrust Compliance Guidelines and Public Meeting Notice**

David Nevius, committee secretary, directed the participants' attention to the NERC Antitrust Compliance Guidelines and the public meeting notice.

### **Review of February 16, 2011 Draft MRC Agenda**

Chairman Tymofichuk reviewed the preliminary agenda for the upcoming February 16, 2011 MRC meeting in Phoenix, AZ (**Exhibit D**).

Chairman Tymofichuk:

- Introduced Bill Gallagher, MRC incoming chairman and Scott Helyer, incoming MRC vice chairman;
- Reminded participants the MRC Informational Session will take place on February 10, 2011 via conference call and webinar;
- Encouraged all new MRC members to attend the New Member Orientation Session, which will take place in Phoenix on Wednesday, February 16, 2011, 9:15–10:15 a.m.;
- Indicated that Tom Berry, chairman, NERC Board of Trustees Nominating Committee will review the process of electing new Trustees in Phoenix during the MRC Closed Session on February 16, 2011, at noon, which is for voting members only. There are four open positions on the NERC Board of Trustees and the election of Trustees will take place during the MRC Open meeting. David Cook, NERC senior vice president and general counsel, stated there needs to be a two-thirds vote of the MRC members in support of each Trustee who is to be elected;

- Encouraged MRC sectors to discuss and submit written input by February 9, 2011 on the following agenda topics:
  - Letter from Gerry Cauley, NERC president and CEO, regarding Top Priority Bulk Power System Reliability Issues
  - Bulk Electric System Definition
  - Follow up from February 8, 2011 FERC Technical Conference – Priorities for Addressing Risks to Reliability
  - Lessons Learned from Recent Alerts and Improvements to Alerts Processes

### **Review of February 17, 2011 Draft Board of Trustees Agenda**

Mr. Cook reviewed the preliminary agenda for the February 17, 2011 Board of Trustees meeting in Phoenix, AZ (**Exhibit E**).

Mr. Cook noted that the compliance filing regarding Order Approving Delegation Agreements is due on February 18, 2011 and it is currently out for comment on the rule changes that are needed for that compliance filing. The comment deadline closes February 8, 2011.

Mr. Cook reminded MRC members that an anonymous online survey went out to voting members of the MRC regarding the effectiveness of the NERC board. The deadline for survey responses is January 15, 2011.

### **Review of February 16, 2011 BOTCC Agenda**

Mr. Nevius reviewed the preliminary agenda for the Board Compliance Committee and strongly encouraged MRC members to attend this meeting in Phoenix, AZ, 10:30 a.m.– noon (**Exhibit F**).

### **Review Schedule of Upcoming Board Committee Conference Calls and Meetings**

Chairman Tymofichuk reviewed the schedule of upcoming board committee conference calls and meetings (**Exhibit G**).

### **Meeting Adjourned**

There being no further business, the call was terminated at 12:00 p.m. EST.

Submitted by,



David R. Nevius  
Committee Secretary

## Future Meetings

### **Action**

Approve a slate of meeting dates through the February 2014 MRC and Board of Trustees meetings. **Note:** The February 2012 dates approved during the February 16–17, 2011 meetings have been changed and the revised dates are part of the slate below.

### **2012 Dates**

February 8–9	Phoenix, AZ
May 8–9	Baltimore/Washington, DC area
August 15–16	Quebec City, Canada
November 6–7	New Orleans, LA

### **2013 Dates**

February 6–7	San Diego, CA
May 8–9	Philadelphia, PA
August 14–15	Montreal, Canada
November 6–7	Atlanta, GA

### **2014 Dates**

February 5–6	Phoenix, AZ
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# NERC

NORTH AMERICAN ELECTRIC  
RELIABILITY CORPORATION

April 11, 2011

Mr. William Gallagher, Chairman  
NERC Member Representatives Committee  
Special Projects Chief  
Transmission Access Policy Study Group  
104 Hampton Meadows  
Hampton, NH 03842

## Re: Policy Input to NERC Board of Trustees

Dear Bill:

First, I congratulate you on running a very successful and informative first meeting of the Member Representatives Committee (MRC). The written input and discussion by the committee on the ERO enterprise strategic direction and goals, the Bulk Electric System definition, and priorities for addressing risks to reliability were very helpful to the Board of Trustees (board) in its deliberations and decision-making.

I continue to encourage MRC members and the industry sectors they represent to provide written input in advance of the May 10–11, 2011 meetings and share their views at the meeting on the key issues on the agendas of the MRC and the board. Your committee's face-to-face discussions are very good, but having written input in advance of the meeting really helps the board members better prepare for and benefit from those discussions. To that end, I am sending this letter earlier in the meeting cycle to give committee members more time to discuss these issues with their respective sectors and develop their written comments.

I see five topics for the upcoming meetings where your input and discussion will be especially helpful to the board.

**Bulk Electric System (BES) and Adequate Level of Reliability (ALR) Definitions (MRC 5)** — The MRC and the board had a lively discussion at our February meetings on these definitions and how NERC should go about developing them. The MRC has formed a task force to discuss the policy issues and questions related to these definitions and we expect to hear a report from you on the status of that work. We will also hear from the chairs of the drafting teams working on the BES definition itself as well as the Rules of Procedure changes that will be required. The definitions of BES and ALR are fundamental to the standards NERC develops, registration of entities, and enforcement of compliance, so the board will be very interested in the direction this effort is heading.

**Facility Ratings Alert Responses and Next Steps (MRC 7)** — NERC’s November 30, 2010 Alert-Recommendation required transmission owners and generation owners of BES transmission facilities to review their current facility ratings methodology to verify that the methodology used to determine facility ratings is based on actual field conditions, and to submit to NERC descriptions of their plans for how and when all transmission lines will be assessed. We heard a preliminary report at the February 16, 2011 MRC meeting on the status of these responses and also that NERC and the Regional Entities expected to complete a reasonableness review of the submitted plans by April 1, 2011. The board will be interested in hearing reactions from affected stakeholders on how this process is progressing and issues or concerns they may have.

**Event Analysis Process Improvements (MRC 8)** — Given that one of the ERO’s strategic goals is to promote and facilitate reliability improvement through event causal analysis, the board is interested to hear discussion on the need for open sharing of technical findings from event analysis reports given the concerns regarding confidentiality, compliance enforcement, and critical energy infrastructure information protection.

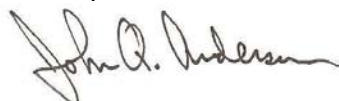
**NERC Metrics (MRC 9)** — At the MRC’s February meeting, we heard an overview report on the state of metrics development, one element of which is the development of Regional Delegation Agreement (RDA) metrics as called for in the RDAs themselves and as identified by FERC in their comments on the Three-Year ERO Performance Assessment. The board is anxious to hear stakeholder comments on the proposed RDA metrics. In addition, the board would like to hear comments on the system reliability metrics that have been developed and are now displayed on NERC’s Reliability Dashboard.

**2012 Business Plan and Budget (MRC 12)** — The Board Finance and Audit Committee (FAC), along with the rest of the board, will be very interested in stakeholder reaction to the draft NERC 2012 Business Plan and Budget, which will be presented and discussed at the MRC meeting. The FAC will seek stakeholder comments during the meeting and follow up as needed in a future session.

This is a longer than normal list of issues on which the board would like to hear stakeholder input, but each issue is important in its own right.

Thank you in advance for providing written comments to Dave Nevius, MRC secretary ([dave.nevius@nerc.net](mailto:dave.nevius@nerc.net)) by **May 5, 2011** so they can be packaged and sent to the board members in advance of the meeting.

Thank you,



John Q. Anderson  
NERC Board of Trustees Chairman

cc: NERC Board of Trustees  
Member Representatives Committee

**Recommended Slate of MRC Members to Serve on the Board of Trustees  
Nominating Committee**

**Action Required**

None

**Background**

On the committee's April 13, 2011 conference call, Chairman Bill Gallagher invited members to volunteer to serve on the Board of Trustees Nominating Committee.

This year, Dave Goulding will chair the Nominating Committee. The other board members on the committee are: John Q. Anderson (ex-officio), Vicky Bailey, Paul Barber, Tom Berry, Janice Case, Fred Gorbet, and Roy Thilly.

Current board members whose terms expire February 2012 are: Bruce Scherr (initially elected 2002), Ken Peterson (initially elected 2006), and Jan Schori (initially elected in 2009.)

In response to Bill Gallagher's solicitation, several members of the MRC expressed interest in serving with MRC Chairman Bill Gallagher and Vice Chairman Scott Helyer on the Board of Trustees Nominating Committee. The following five MRC representatives are recommended to the Board for inclusion on the Nominating Committee.

- Bill Gallagher (MRC chairman)
- Scott Helyer (MRC vice chairman)
- John A. Anderson (Large End-Use Customer)
- Carol Chinn (Investor-Owned Utility)
- Craven Crowell (Regional Entity)

## Bulk Electric System Definition

### Action Required

None

### Background

At its February 16, 2011 meeting, the NERC Member Representatives Committee (MRC) had an extensive discussion on NERC's approach to developing a revised definition of Bulk Electric System (BES) in response to Commission Order 743.

Emerging from that discussion was a general agreement that NERC's efforts to develop a revised BES definition and associated exemption criteria would benefit from some high-level policy input from the MRC. To that end, Bill Gallagher, chair of the MRC, formed a task force comprising several MRC members and others to develop that policy input. In addition to the definition and associated exemption criteria, this task force will also address the policy issues related to the definition of Adequate Level of Reliability (ALR).

The following individuals, identified as representative of the broad interests of the MRC and the stakeholder members it represents, were invited to participate in this task force. Two members of the NERC board also expressed an interest in participating, and have been added to the list.

Bill Gallagher (MRC Chair)	Larry Nordell
Scott Helyer (MRC Vice Chair)	Robin Lunt
Dave Nevius (MRC Secretary)	Allen Mosher
John A. Anderson	Tim Gallagher (RFC)
Barry Lawson	Ed Schwerdt (NPCC)
Tom Burgess	
Sam Holeman	<u>NERC Board:</u>
Julius Pataky	Vicky Bailey
Paul Murphy	Ken Peterson
John DiStasio	Gerry Cauley

The task force held an initial scoping meeting by conference call on March 25 to identify specific policy issues and questions related to BES and ALR and assigned several of these issues and questions to task force sub-teams. A follow-up call, open to all MRC members, was held on April 13 on which the sub-teams reported on their preliminary discussions on the various BES and ALR policy issues and questions. The chairs of the BES definition and Rules of Procedure drafting teams also reported on the status and timetables of their respective drafting activities.

The task force initially identified the following policy issues and questions as in need of high-level policy input, along with some preliminary thoughts and observations on each.



## ALR Issues and Questions

- *To what extent should resilience to and recovery from physical and/or cyber attacks be part of the ALR definition?*
  - Reviewed the six characteristics of ALR.
  - Range of contingencies considered, including credible physical and cyber contingencies.
  - Expect system to be resilient to extreme contingencies, regardless of their causes, and to prevent serious damage to equipment and be able to be restored.
  - Current definition appears to address consequences of physical and/or cyber attacks implicitly.
  - May need to consider revising ALR definition to make more explicit.
  
- *How should cost/benefit be factored into ALR? How and by whom should those decisions be made?*
  - Cost/benefit currently considered implicitly in industry consensus standards development process.
  - ALR definition could go through same process as standards.
  - Alternative to measure costs explicitly.
  - Review NPCC pilot on explicit consideration of “cost effectiveness” of standards.
  
- *Is the impact of all load loss equal? What are the circumstances when load loss represents actions in support of ALR (load shedding in response to Energy Emergency Alerts - EEA3) and when it doesn't?*
  - Alternative statement of question: To what extent is load loss, and the root causes of it, considered evidence of an inadequate level of reliability?
  - Looking at defining different categories of load loss and different weighting depending on criticality of loads.
  - Part of design basis in some cases; e.g., underfrequency/undervoltage load shedding, manual load shedding, etc.
  - ALR used to guide standards, metrics, etc.
  - More a question of principle; what is avoidable vs. unavoidable load loss?
  - May need to consider revising ALR definition to include some loss of load concept.
  
- *How should “cascading” be defined?*
  - Definition needs improvement.
  - Categorize what constitutes different types and levels of cascading.
  - How to define “success” or “failure” of system.
  - Loss of “operational control” of BES facilities of another registered entity

- *Do we have adequate metrics for measuring performance/results for the current attributes of ALR?*
  - ALR Task Force being formed by standing committees along with Reliability Metrics Working Group prepared to address.

#### BES Definition and Exemption Process Issues and Questions

- *Should resources and other devices located on the distribution system be considered part of the BES based on their function and importance to the reliability of the BES; e.g., distributed generation; smart grid devices; PHEVs; demand response controls; underfrequency/undervoltage load shedding relays; manual load shedding controls; capacitor/reactor controls; etc.*
  - Related closely to discussion of scope of Section 215.
  - Difference between Bulk Power System (BPS) and BES.
  - Should facilities and systems located on the distribution system but whose functions are necessary for the reliability of the BPS be part of BES; e.g., underfrequency/undervoltage load shedding; capacitor/reactor switching; manual and automatic load shedding, etc.
  - Question remains on whether and to what extent distributed demand response facilities and elements should be considered part of the BES; possibly consider when these facilities have a common collection point. (Similar approach possible with distributed generation.)
  - Cyber security issues related to smart grid devices and systems and their possible impact on BPS reliability need further consideration.
  - Questions and issues, already complex from a technical standpoint, are made more complex by jurisdictional issues.
- *Should any new definition of the BES (and related exemption criteria) endorse the need for some kind of “grandfathering”? What should be the transition plan for newly identified facilities and elements?*
  - Transition plan may not be necessary in Regions that already have a 100 kV bright line BES definition.
  - Must have reasonable transition plan to address treatment of facilities that are included under the BES definition.
  - Absence of transition plan could negatively impact by rushing solutions.
  - Cross-border Regional Entities in best position to work with government authorities in Canada regarding applicability.

- *Should responsibility for BES facilities owned by small entities be assigned to other entities? To what extent do the current Joint Registration Organization (JRO) and Combined Functional Registration (CFR) procedures provide for this?*
  - NERC Rules of Procedure provide workable solutions for addressing compliance responsibilities of small entities via the JRO and CFR procedures.
  - Provides flexibility in entity registration on an asset by asset or standard requirement by standard requirement basis.
  - Efficient, documented compliance coverage with no gaps or overlaps.
  - Does require consent of both parties.
  - Termination of a JRO or CFR can potentially place an entity in a non-compliance situation, unless an adequate transition is provided.

Mr. Gallagher, along with the chairs of the BES Definition and Rules of Procedure drafting teams, will report on the status of these activities and encourage discussion and comment.

## **Analysis of Cold Weather Impacts on the Bulk Power System**

### **Action Required**

None

### **Background**

NERC initiated a review of the widespread outages of electric generating facilities and disruptions in electric and natural gas services that occurred the first week of February 2011 in Texas and other parts of the Southwest when unusually cold weather spread throughout the region.

Tom Galloway, senior vice president and chief reliability officer, will discuss the scope, status, timeline, and next steps.

This discussion will include the following:

- Sequence of events
- Summary of the generation and load lost
- Relation to revised events analysis process
- Unique aspects of this event
- Expected deliverables
- Related reliability assessment activities

## **Facility Ratings Alert Responses and Next Steps**

### **Action Required**

None

### **Background**

NERC's November 30, 2010 Alert-Recommendation required transmission owners and generation owners of BES transmission facilities to review their current facility ratings methodology to verify that the methodology used to determine facility ratings is based on actual field conditions, and to submit to NERC descriptions of their plans for how and when all transmission lines will be assessed.

NERC gave a preliminary report at the February 16, 2011 MRC meeting on the status of these responses and indicated that NERC and the Regional Entities expected to complete a reasonableness review of the submitted plans by April 1, 2011.

Tom Galloway, senior vice president and chief reliability officer, will discuss how this process is progressing and the feedback to date from industry trade groups and forums.

These discussions will include:

- A summation of assessment plans received
- Positive aspects of those plans
- Common shortcomings in some plans
- Key steps taken and upcoming

### **Attachments:**

1. November 30, 2010 – Alert Recommendation
2. November 30, 2010 – Letter to Industry CEOs from Gerry Cauley
3. January 14, 2011 – Facility Ratings Q&A
4. April 26, 2011 – Letter to Industry Trade/Forums from Tom Galloway

## Recommendation to Industry Consideration of Actual Field Conditions in Determination of Facility Ratings

Initial Distribution: October 7, 2010

Updated: November 30, 2010 (to revise schedule)

**NERC and the Regional Entities have become aware of discrepancies between the design and actual field conditions of transmission facilities, including transmission conductors. These discrepancies may be both significant and widespread, with the potential to result in discrepancies in line ratings. The terms “transmission facilities” and “transmission lines” as used herein include generator tie lines, radial lines and interconnection facilities that are included in the scope of the current NERC-approved definition of Bulk Electric System.**

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**Status:** Receipt Acknowledgement Required by October 20, 2010  
If you have previously acknowledged receipt of this Recommendation, you need not do so again.  
Reporting Required by January 18, 2011 (revised date)



**PUBLIC:** No Restrictions  
[More on handling >>](#)

**Instructions:** This NERC Recommendation is not the same as a Reliability Standard, and a failure to implement this Recommendation will not constitute the sole basis for an enforcement action. However, pursuant to Rule 810 of NERC's Rules of Procedure, you are required to report to NERC on the status of your activities in relation to this Recommendation. For U.S. entities, NERC will compile the responses and report them to the Federal Energy Regulatory Commission (FERC). NERC will use the responses from Canadian entities for its own purposes but will not include those responses in the compilation it sends to FERC.

Issuance of this Recommendation does not lower or otherwise alter the requirements of any approved Reliability Standard, or excuse the prior failure to follow the practices discussed in the Recommendation if such failure constitutes a violation of a Reliability Standard.

**Distribution:** **Primary Distribution: Primary Compliance Contacts for** Transmission Owners and Operators, Generator Owners and Operators, Reliability Coordinators, Transmission Planners, and

Planning Authorities.

[Who else will get this alert? >>](#)

[What are my responsibilities? >>](#)

**Primary Interest Groups:**

Transmission Planning Engineers, Transmission Maintenance Engineers, and Transmission Planners

**Recommendation:**

Transmission Owners and Generation Owners of transmission facilities that are considered part of the Bulk Electric System should review the current Facility Ratings Methodology for their solely and jointly owned transmission lines to verify that the methodology used to determine facility ratings is based on actual field conditions. Line ratings depend on many limiting factors, including transmission facility placement, tower height, topographical profiles, and maintaining adequate conductor clearances (*i.e.*, conductor-to-ground, conductor-to-conductor) under a variety of ambient and loading conditions.

- Transmission Owners and Generation Owners should determine if their Facility Ratings Methodology will produce appropriate ratings, even when considering differences between design and actual field conditions.
- Transmission Owners and Generation Owners should review their transmission facility ratings to confirm that any differences observed between design and actual field conditions are within the design tolerances as defined by the Registered Entity's Facility Ratings Methodology.

If Transmission Owners and Generation Owners have not previously verified that the facility design, installation, and field conditions are within design tolerances when the facilities are loaded at their rating, the Transmission Owners and Generation Owners should describe its plans to complete an assessment of its facilities to verify whether the actual field conditions conform to the entity's design tolerances in accordance with its Facility Ratings Methodology. Assessments should be structured such that, at a minimum, facilities with the highest impact to bulk power system reliability be performed in 2011, facilities with medium impact to reliability be assessed in 2012, and those facilities with the lowest impact in 2013. The description of the plan for how and when all transmission lines will be assessed should be submitted to NERC by **January 18, 2011**. NERC recommends that the Transmission Owners and Generation Owners perform assessments using methods or technologies with adequate precision to show whether the actual field conditions support the entity's facility ratings. The Transmission Owners and Generation Owners should also explain how these measurements and assessments will be accomplished and the estimated length of time to complete the activity for all applicable facilities. Transmission Owners and Generation Owners requiring an extension beyond the three-year assessment timeframe should

submit their justification in the January 18, 2011 report.

During conduct of the assessment, if the Transmission Owners and Generation Owners determine that the actual conductor clearances are not within the entity's design tolerances under existing or design conditions and as a result, facility ratings are in error, the Transmission Owners and Generation Owners should coordinate their findings of the assessment with their respective Reliability Coordinator, Transmission Operator, and Generator Operators. This coordination should include establishing interim mitigation plans to address the assessment findings and any actions required to maintain bulk electric system stability and reliability. Although such plans may include derating of facilities consistent with actual field conditions, consideration should be given to optimizing the overall robustness and reliability of the bulk power system during the remediation period. The entity should also notify its Transmission Planner and Planning Authority of any limitation in the facility ratings due to the interim mitigation plan and update all operating instructions, procedures, SOLs, IROLs, study models and databases used to assess the system during the remediation period.

Additionally, Transmission Owners and Generator Owners must provide a report to the Regional Entity summarizing the assessment findings by December 31, 2011 for high priority facilities, by December 31, 2012 for medium priority facilities, and by December 31, 2013 for lowest priority facilities. This report should identify facilities for which facility ratings are determined to be in error or inconsistent with actual in-field conditions, and an expected timeline for remediation to correct the conditions or modify the facility ratings. If remediation is expected to require a timeframe greater than one year from identification of the issue, the Transmission Owners and Generator Owners should submit a plan to remediate to the Regional Entity for approval.

In the situations described, NERC considers actions to maintain the reliability and integrity of the bulk power system to be of paramount importance. NERC recognizes that assessment of existing conditions and any necessary remedial actions require careful planning, coordination, and sequencing to avoid introducing unintended new risks.

Therefore, in summary, Transmission Owners and Generation Owners with solely or jointly owned transmission facilities (including generator tie lines, radial lines and interconnection facilities that are included in the scope of the current NERC-approved definition of Bulk Electric System) are to take the following actions:

1. Transmission Owners and Generation Owners must provide a report by January 18, 2011 with a plan to conduct an assessment using a staggered schedule as follows:



- a. High priority facilities by December 31, 2011
  - b. Medium priority facilities by December 31, 2012
  - c. Lowest priority facilities by December 31, 2013
2. For all transmission facilities (including generator tie lines, radial lines, and interconnection facilities) meeting the following conditions:
    - a. The existing or as-built conditions are different from the design conditions for the facilities; and
    - b. Those differences between actual and design conditions result in incorrect ratings for the facilities

Transmission Owners and Generator Owners should coordinate with each applicable Reliability Coordinator, Transmission Operator, Generator Operator, Planning Authority, and Transmission Planner regarding interim mitigation strategies.

3. Transmission Owners and Generation Owners must provide a report to its Regional Entity summarizing their assessment findings by December 31, 2011, 2012, and 2013 for high, medium, and lowest priority facilities, respectively, identifying facilities for which facility ratings are determined to be in error or inconsistent with actual in-field conditions. This report should also include an expected timeline for remediation to correct the conditions or modify the facility ratings.
4. If Transmission Owners and Generation Owners require longer than one year from the date the issue is identified to remediate an issue, the entity should submit its remediation plan to the Regional Entity for approval.

**Reporting  
Instructions:**

Primary Compliance Contacts at Registered Entities in receipt of this notice are required to acknowledge their receipt of this notice no later than 5:00 PM EDT on **October 20, 2010**. Transmission Owners and Generation Owners in receipt of this notice are required to report plans to address this Recommendation, including assessment methods to be used, and a timeline and priorities for any necessary remediation, via the online acknowledgement tool by filling out the attached questionnaire no later than 5:00 PM EDT on **January 18, 2011**. Access to this tool has been provided to Primary Compliance Contacts.

Respondents will need the following information to complete the questionnaire: NERC Compliance Registry ID Number, Registered Entity Name, and Primary Compliance Contact Information. Respondents will also need to respond whether or not their organization has appropriately addressed this Recommendation. An officer or other authorized representative of the recipient must certify the completeness and accuracy of the

response.

**Webinar:** NERC will host a Webinar to provide an overview of the issues and to answer questions regarding the alert and its associated response. The details for the Webinar are as follows:

Date: October 28, 2010  
Time: 1:00 – 3:00 PM Eastern

Registration Link: <https://cc.readytalk.com/r/dd8amqsvvog>

This conference will be using a broadcast audio function that allows audio and video streaming directly through the participant's computer (a conference number is also available for those that don't have Web access).

Specific access information will be provided to those who register at the link above. Registration is complimentary, but limited.

**Background:** A Transmission Owner experienced a conductor-to-ground fault caused by a vegetation contact with a bulk power system line that resulted in a lockout of that transmission line. Although vegetation caused the fault, the subsequent evaluation indicated that the conductor-to-ground clearance was less than expected. This was due to substantial inconsistencies between the actual topography within the easement of the transmission line and the design of the line. Additional evaluation determined that the root cause of the outage was due to insufficient clearances and other errors that occurred when the transmission line was originally designed and constructed.

As a direct result of the outage, the Transmission Owner contracted with a company that utilizes Light Detection and Ranging (LiDAR) and Power Line Systems – Computer Aided Design and Drafting (PLS-CADD) technologies to survey its 230 kV and 345 kV systems. The data was used to determine conductor-to-vegetation and conductor-to-ground clearances.

Using these advanced technologies, the Transmission Owner identified over 100 conductor-to-ground clearance issues that had gone previously undetected. This information was used to adjust the facility ratings for many of the lines where clearance issues were observed until modifications to the transmission line configuration or changes to the topography could be made. Other examples of inaccurate historical information included, but are not limited to, misplaced structures or supports, inadequate tower height, and ground profile inaccuracies.

NERC and the Regional Entities are concerned that Transmission Owners and Generator Owners have, in some instances, not considered existing field conditions when establishing facility ratings for transmission facilities, including transmission conductors. Transmission Owners should strive to achieve a

heightened awareness of the actual operating conditions of their respective transmission conductors and take prompt corrective action as necessary.

**Contact:** Gerry Adamski  
Director, Situation  
Awareness and Training  
609-452-8060  
[Gerry.adamski@nerc.net](mailto:Gerry.adamski@nerc.net)

R-2010-10-07-01

*You have received this message because you are listed as the designated contact for your organization on the North American Electric Reliability Corporation's compliance registry. If believe you have received this message in error, please notify the sender immediately and delete or otherwise dispose of all occurrences or references to this email. If you have questions about your membership in this list, please contact Jason Wang at NERC by calling 609.524.7007 or emailing Jason directly at: Jason.wang@nerc.net.*

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November 30, 2010

Industry CEOs

Ladies and Gentlemen:

On October 7, 2010 NERC issued the *Recommendation to Industry: Consideration of Actual Field Conditions in Determination of Facility Ratings* (Recommendation), requiring selected entities to submit plans by December 15, 2010, to assess their transmission facilities and mitigate any discrepancies found between actual field conditions and design specifications. Since NERC issued this alert you have shared your many concerns regarding the potential impacts and impracticality of implementing all aspects of this alert within the specified timeline. I have heard you; let me share my thoughts on the importance of this activity and clarify expectations for responding to the alert.

The Electric Reliability Organization (ERO) model contemplates that, from time to time, possible risks that could affect electric reliability may be identified such that NERC will need to identify certain actions necessary to mitigate these risks. This is one such risk. As a result of detailed analysis of one entity's compliance with reliability standard FAC-003 (Transmission Vegetation Management Program), the entity performed a system-wide assessment that identified a number of discrepancies in facility ratings caused by differences between field conditions versus design specifications. Additional discussions with other entities who have undertaken assessments similar to those contemplated by the NERC Recommendation have confirmed these findings — that numerous discrepancies from design specifications are being found, which have the potential to reduce the facilities' calculated ratings. As a result, under my leadership and direction, NERC issued the Recommendation to proactively identify the scope of the risk, and promote corrective actions, both in the interim and in the long term to address the concerns identified.

I understand and agree that the task before us is a challenging one. But importantly, it is a task that places reliability as the foremost consideration and has widespread support within the industry. While the current condition was created over many years; I expect our response will be proactive and measured in a manner that maximizes reliability. The goal is not to address this issue as a temporary correction. Rather, it is a strategy that creates a systematic and sustainable path for the future to effectively identify and address clearance issues in bulk power system rights-of-way, as needed to ensure that line ratings are accurate and reflective of actual conditions.

In consideration of the complexity of this task, I am modifying the response date for submittal of plans from December 15, 2010 to January 18, 2011. Furthermore, I am modifying the expected timeline for identification of facilities for which actual conditions may impact line ratings. First,

reporting of identified discrepancies applies only to those facilities within the scope of the NERC-defined Bulk Electric System for which facility ratings are determined to be in error or inconsistent with actual conditions. Discrepancies for the highest priority facilities with regard to bulk power system reliability should be identified and reported to your applicable Regional Entity no later than December 31, 2011. Medium priority facilities should be assessed and discrepancies reported no later than December 31, 2012, and lowest priority facilities no later than December 31, 2013. Entities requiring longer than three years to complete their initial assessments should provide justification within their plans submitted by the January 18, 2011 date. I aim to avoid any action by entities focused on expediency or to avoid perceived compliance risk that undermines the quality of the review and the creation of a systematic and sustainable path forward.

In general, your plan for performing the assessments should contemplate the following categories in order of importance:

- Transmission facilities that are components of an identified IROL or key transfer paths
- Transmission facilities identified as critical to reliability
- Facilities in higher voltage classes before lower voltage classes

Additional prioritization should be considered based on the most heavily loaded lines within each category, spans with known transmission underbuilds and crossing situations, other spans that may be suspect, and spans for which access to rights-of-way has been previously requested by external parties. Whereas entities have expressed considerable concern regarding the availability of certain technologies (e.g., LIDAR) to complete these assessments, NERC is not prescribing how you should assess your system. Your individual circumstances will drive how to best achieve an accurate portrayal of in-field conditions relative to design specifications and facility ratings and should be reflected in your plans. If concerns regarding the availability of LIDAR services exist, then your plan should identify alternatives (e.g., conductor monitoring, field visits, etc.)

Each entity reporting facilities with rating discrepancies in accordance with the revised schedule outlined above should include in their report an expected timeline for remediation to correct the conditions in the right-of-way or modification of the facility ratings. Remediation should be completed as quickly as practical, consistent with maintaining bulk power system reliability. Any remediation requiring longer than one year from the date the discrepancy is identified should be documented in a mitigation plan submitted to the Regional Entity for approval.

Finally, I recognize that the industry has raised significant questions about the implications of this Recommendation for registered entities' compliance with the reliability standards. It is our view that a difference between design criteria and actual field conditions is not a *per se* violation of the reliability standards. Whether such a difference is determined to be a possible violation of any of the reliability standards will depend on the facts of any given case. To provide clarity on this point, I instructed NERC staff to prepare the attached draft Compliance Application Notice (CAN) to explain how the conditions addressed in the Recommendation interrelate with compliance with the reliability standards.

As noted above, I believe it is important the industry approach its response to the Recommendation by putting the interests of reliability of the bulk power system ahead of concerns about discovering a possible non-compliance and any potential penalty that may ensue. To that end, and per our sanctions guidelines, NERC and Regional Entity enforcement staff will take account of thorough

assessments completed in response to this Recommendation in accordance with the revised timelines outlines above, including self-disclosure of any compliance gaps and voluntary corrective action. Such activities will be considered as significantly mitigating factors for any possible violation identified as a result of the assessments.

To further ensure compliance concerns do not supersede the desired activity under the Recommendation, I have directed NERC and Regional Entity staff to exercise their enforcement discretion to hold the processing of all possible violations reported as a result of the assessments until the entity's assessments are complete, as long as the registered entity reporting such possible violations is proceeding in good faith to complete the assessments in accordance with the revised timelines. This will allow registered entities to allocate their resources to the tasks called for under the Recommendation, and will ensure the record for any possible violations is complete, including evidence of the full scope of all creditable voluntary corrective actions taken by a registered entity in response to the Recommendation.

In the unlikely circumstance an actual event occurs in which NERC or the Regional Entity determines a discrepancy between actual field conditions and design specifications was a cause or contributing factor, then NERC or the Regional Entity would proceed to investigate that case directly without delay. Similarly, any possible violations of FAC-003 should continue to be reported without delay and may be processed separately and immediately by the Regional Entity or NERC.

I am confident that the effective handling of this significant issue will demonstrate our industry's commitment to reliability in a forthright manner. Proactive plans and assessments, coupled with rigorous follow-up throughout the term of mitigation timelines are imperative. This, in turn, should culminate in greater confidence on the part of the applicable governmental authorities of our commitment to reliability.

Sincerely,

A handwritten signature in black ink that reads "Gerald W. Cauley". The signature is written in a cursive style with a large, stylized initial "G".

Gerald W. Cauley  
President and CEO

## Q&A - Consideration of Actual Field Conditions in Determination of Facility Ratings (1/14/2011)

### Introduction

On October 7, 2010, NERC issued a Recommendation to Industry entitled “Consideration of Actual Field Conditions in Determination of Facility Ratings” that was updated on November 30, 2010. Subsequently, NERC has received numerous questions, hosted two webinars, developed a draft Compliance Application Notice, and provided a letter from President and CEO Gerry Cauley regarding the alert. This document provides answers to many of the questions NERC has received.

### Administrative

1. When is the Gerry Cauley letter to CEOs expected to be released? Where can I find a copy of the letter?

*Gerry Cauley’s letter, the draft Compliance Application Notice, and the updated alert containing the revised reporting dates were issued on Tuesday, November 30, 2010. Links to these documents are found on the following NERC Web page:*

*[http://www.nerc.com/filez/facility\\_ratings\\_alert.html](http://www.nerc.com/filez/facility_ratings_alert.html).*

2. Will Alert be re-issued based on the letter?

*The alert, originally issued on October 7, 2010, was updated with new reporting dates and made available on November 30, 2010.*

3. Where can I find the question and answer document, the slides from the webinar, the streaming broadcast from the webinars, and the draft compliance application notice?

*All supporting materials regarding the Facility Ratings alert are located at the following link:*

*[http://www.nerc.com/filez/facility\\_ratings\\_alert.html](http://www.nerc.com/filez/facility_ratings_alert.html).*

4. This approach seems to suggest significant work and discretion on the part of the Regional Entities. Have estimates been made on the workload and how they will maintain consistency?

*While we understand the effort that will be necessary to support this activity, no specific estimate has been developed. NERC and the Regional Entities will maintain ongoing dialogue regarding the expectations for the alert, establishing general guideposts to facilitate*



*consistent implementation of those expectations, and then routine ongoing assessments to identify anomalies that require adjustment.*

5. Where do we direct comments on the letter and CAN?

*NERC issued the CAN in draft format in order to utilize the standard CAN input process. Refer to the following Webpage for submitting comments:*

*<http://www.nerc.com/page.php?cid=3/22/354>. Comments on other Facility Ratings alert documents or issues surrounding the alert should be directed to Gerry.Adamski@nerc.net.*

6. Has the NERC Board been involved in the development of the CEO letter and the FERC discussions?

*The NERC Board has been advised regarding the CEO letter and the FERC discussions but not directly involved, except for Gerry Cauley. However, at the NERC BOT and MRC meetings in early November, Board members did participate in discussions with industry representatives regarding their alert concerns. The BOT will be kept apprised of developments related to this Alert through briefings in various forums.*

7. Recommendation for future alerts: apply a designation (name, number, etc) to them so they can be discussed easier.

*Alerts are given a unique identifier, located at the end of the alert document. The Facility Ratings alert is designated R-2010-10-07-01. NERC staff will ensure this unique identifier is included in related discussions.*

### **Alert Classification**

8. Although the alert is classified as a recommendation, NERC is expecting field measurements and mitigation that will involve considerable time and expense. The alert also states that no remediation plan may extend beyond one year from identification without submitting the plan to the Regional Entity for approval. This sounds like required actions, not required reporting. Why isn't this alert considered an essential action that also requires NERC board approval? Are we required to perform the actions contained within this NERC recommendation? Is this authority vested in NERC's Rules of Procedure?

*The Facility Ratings alert is properly classified as a "recommendation". Recipients of the alert are required, per NERC's Rules of Procedure, to report to NERC the status of their actions taken in response to the recommendation. NERC cannot compel specific actions to be taken using a recommendation. However, NERC strongly encourages and expects that entities will give due consideration to the significance of the concern expressed in the alert and take the recommended action to mitigate any issues identified as a result.*

### **NERC Alerts System**



9. Will it be possible to modify the Alerts System such that the user can specify the officer to whom an alert response should be directed for approval?

*NERC will evaluate this opportunity for improvement with its alert system vendor.*

## **Assessment**

10. Re-confirmation of design and as build with field conditions can be a huge undertaking. It may not be possible to perform a LiDAR survey, process data, create a model in PLS-CADD, and analyze the model for potential clearance issues in the timeframes given. Plus, a large part of the country is just a few weeks away from snow season, making it difficult if not impossible to conduct surveys and/or assessments.

*Recognizing these issues, NERC recently revised its expectations for performing the assessments and mitigating identified issues. The plan for performing the assessments is now due January 18, 2011. Reports describing the assessments are due at the end of 2011, 2012, and 2013 reflecting transmission facilities that are considered high, medium, and lower priority, respectively.*

11. EEI estimates that it will cost about \$1,000/mile, and \$450 million across the country to just do the analysis and companies are not sure if this can be done within the time limit provided. Can this process be extended and prioritized, such as 345 kV and up transmission lines first to be followed by 230 kV and 138 kV lines, etc?

*On November 30, 2010, NERC modified its expectations for reporting on the assessments that addresses this concern.*

12. How did NERC determine the assessment and mitigation deadlines, especially considering that Duke Energy had a three year mitigation program and only analyzed and upgraded 230 kV and 345 kV lines?

*NERC became increasingly concerned as it received feedback from multiple entities regarding the large number of issues being identified during the assessment. This heightened level of concern amplified the need to better scope and address the issue in a shorter time frame than that identified in the Duke situation, initially thought to have been an isolated issue.*

## **Basis**

13. NERC notes significant concern with respect to the issues outlined in the alert, yet only one specific example is cited. Can NERC provide additional insight regarding the basis for the concern?

*NERC cites one example in the alert but has first-hand information from multiple entities who have undertaken assessments and providers of those services such as those recommended in the alert. This feedback routinely characterizes the issues identified to*

*number in the hundreds for individual entities, which led NERC to issue the recommendation.*

14. If NERC wants the industry to assess reliability in a new fashion, why have they not approached this in reasonable timelines (i.e. 5 year timeline with annual reporting)

*Considering the potential scope and impact of this issue on facility ratings, NERC believes it modified dates present a reasonable timeframe.*

## **Compliance**

15. Does NERC expect that entities will need to self-report potential compliance violations resulting from this Alert?

*Yes. Please refer to the Gerry Cauley letter for general and the draft CAN for specific guidance on managing the compliance aspects associated with the alert.*

16. If clearance violations are found from field inspections that would result in a reduction in the facility rating, what NERC standards should be self reported as a potential violation? Is the expectation that every NESC clearance violation identified by the assessment be self reported?

*The answer depends on the level of detail contained in the Facility Ratings methodology per FAC-008 and FAC-009 and whether it contains the inclusion of actual clearances or the physical application of design criteria in the field. NERC believes the inclusion of these detailed aspects in an entity's Facility Ratings Methodology is very favorable and encourages its continued use. As discussed in the posted CAN (specified in the next question), an entity will receive highly favorable treatment in compliance space for its proactive approach to reliability and support of this recommendation. Refer to the draft CAN where various scenarios are described.*

17. Can you please repeat the discussion on positive action? Wouldn't NERC wait until assessment and mitigation take place before taking any compliance action?

*The following excerpt is included in the draft CAN:*

*Registered entities that included the actual physical application of its design criteria in the field for individual Facilities and/or actual clearances for individual Facilities in its FRM have exhibited an attention to detail and a concern for reliability. In the event a registered entity discovers a noncompliance as a result of this Recommendation, the registered entity's continuation of its robust FRM; timely and thorough evaluations of its system using accurate measurement methods and technologies; timely self-disclosure of any compliance gaps; prompt corrective actions and consistent completion of its Mitigation Plan milestones will be strong considerations in the determination of a zero-dollar penalty.*

*Further, NERC and Regional Entity staff will exercise enforcement discretion to hold the processing of all possible violations reported as a result of the assessments until the entity's assessments are complete, as long as the registered entity reporting such possible violations is proceeding in good faith to complete the assessments."*

*With respect to waiting until mitigation actions are taken until processing possible violations, NERC expects compensatory actions to be taken in the interim when an issue is identified. These actions will be faithfully considered in assessing the entity's good faith efforts to respond to the recommendation.*

18. If the ratings methodology (under FAC-008) is consistently applied as written today and the overall rating (FAC-009) is maintained, would there be any compliance issue?

*Potentially not. The issue depends on the level of detail contained in the facility ratings methodology. However, entities that have and continue to include the actual physical application of its design criteria in the field for individual Facilities and/or actual clearances for individual Facilities in its FRM will receive very favorable treatment in any resultant compliance activity. This approach is an indicator of a very supportive reliability culture and will be acknowledged and considered significantly in compliance space.*

19. If a company transitions to a LIDAR-based approach, how should it revise its methodology required for FAC-008 and FAC-009 in order to maintain compliance throughout the transition?

*An entity that transitions its ratings methodology to incorporate advanced technologies to improve accuracy would be viewed highly favorably in any possible compliance activities. These actions demonstrate positive steps to ensure continued reliability. One suggestion to potentially avoid compliance issues might be to outline the transition plan in the facility ratings methodology itself, and then finalize the plan when the transition is completed.*

20. Compliance discretion can be a problem in compliance. What instruction/guidance will NERC provide to the Regional Entities as to the discretion the industry has in this matter?

*NERC and the Regional Entities will maintain ongoing dialogue regarding the expectations for the alert, establishing general guideposts to facilitate consistent implementation of those expectations, and then routine ongoing assessments to identify anomalies that require adjustment.*

21. If a company changes its ratings based on actual field conditions, but the documented methodology per FAC-008 refers to the design as the basis, will the company be in violation of its Rating Methodology? Or does this alert require all TOs and GOs to change their rating methodology to include actual field conditions?

*This scenario could potentially result in a possible compliance violation. However, this alert does not "require" entities to change their methodology. That being said, NERC*

*highly recommends that methodologies identify that facility ratings should be predicated upon actual in-field conditions.*

22. Can we be audited based on the answers provided to the NERC Alert?

*Strictly speaking, yes, as the alert process falls within the realm of NERC's ERO activities. However, NERC has attempted to focus the industry's efforts toward the reliability implications of the facility ratings issue and defer any compliance issues until after the scope of the reliability concern is understood.*

23. Does NERC anticipate compliance CVIs as a result of registered entities' submittals?

*NERC expects that any possible violations will be self-reported and that actions to investigate these issues will be processed as would any possible violation.*

24. Does the reference to a mitigation plan imply a "violation" of a NERC standard?

*Not in the context of the alert. If there is a discrepancy in a facility ratings based on in-field conditions that differ from design, the entity is recommended to mitigate the issue. This does not imply a violation of the standard, but is a recognition of an issue that should be remedied.*

25. How do you differentiate this alert from compliance with FAC-008?

*The issue of possible compliance with FAC-008 and FAC-009 is predicated upon the detail of the entity's facility ratings methodology. Implementing the recommendation may or may not result in compliance issues as discussed in the draft CAN.*

26. What are consequences if entities choose not to comply or meet the deadlines in the alert?

*NERC has no formalized penalty mechanism included in its Rules of Procedure for violations therein. However, NERC reports to US and Canadian regulatory authorities the results of the recommendation and the industry response. Failures to report or failures to act will be included in this report. Moreover, NERC will consider an entity's response to alerts as a factor in any subsequent compliance matters involving those identified issues.*

27. Transmission line clearances are based on safety requirements to eliminate electrocution, which are much more tolerant than vegetation management expectations. Why isn't compliance with FAC-003 sufficient evidence to address this issue?

*FAC-003 only addresses the issues of vegetation and their impact on transmission facilities 200 kV and above. It does not specify clearances of conductors to other structures or to the ground, nor does it address any changes in topography that may have occurred since the lines were built. In addition, the scope of the recommendation includes all BES facilities.*

## **Generation Owner**

28. What are the Generator Owner expectations for responding to the recommendation?

*If you are a generator owner registered in NERC's compliance registry as having facilities meeting the definition for inclusion therein, you are subject to the recommendation. The facilities that are in scope for the alert are the generator tie-lines (or portions thereof) owned by the entity that connect the plant to the grid. Specifically, these are the lines from the high voltage side of the generator step-up transformer that connect the generating units to the transmission grid. If you own such facilities, you are required to report on the status of assessment and mitigation activities per the recommendation. However, the focus is on the transmission lines that access rights-of-ways to connect the units to the grid, not necessarily in-plant facilities.*

29. We are a GO/GOP and we conduct annual performance testing on each unit to achieve accurate maximum power output for each unit. If we submit this annual testing data does this meet the reporting protocol requirements?

*Not necessarily as this information provides no insight on the state of the lines that connect the unit to the grid.*

30. Can you comment on how a generating plant should set priorities?

*Generally, entities are expected to establish priorities for their facilities based on reliability impacts using general guidance in Gerry Cauley's letter. For generators, reliability impacts would be considered greater for units that are: labeled as must run units, needed for voltage support, part of a special protection scheme for automated runback or ramp-up, identified specifically as a primary action to mitigate an IROL violation, or blackstart units for example. Other considerations would include aggregate plant output across the generator tie-lines with greater importance given to higher values. For certain of these, the Generator Owner may need to coordinate with its Transmission Owner/Operator to determine if a particular plant or unit is involved.*

31. Does the alert apply to generation interconnection tie lines that are radial only and do not serve load?

*Yes if the generator is considered part of the bulk electric system.*

32. As a GO/GOP, without lines, would it be appropriate then, to respond that we are aware of the alert, but do not own or operate BES transmission facilities, so we consider our obligation relative to this specific Alert complete?

*Yes, this would be an appropriate response. But please provide an approved response so NERC can track your submission.*

33. How would GO/GOP learn about the transmission line ratings? Is there a coordination need between GO/GO and TO/TOP?

*If you are a Generator Owner that is subject to the NERC standards, you are obligated to have a facility ratings methodology per FAC-008 for owned facilities.*

34. For a generation facility with a point of interconnection being a substation located at the plant, what constitutes a "transmission circuit" for the purposes of the count?

*The line connecting from the high side of the step-up transformer to the substation. Whereas the primary concern is on rights-of-way whose topography may have changed or otherwise is inconsistent with the design basis, generator owners should also validate that in-plant conditions haven't been modified that would potentially affect the appropriateness of line ratings. However, this is ancillary to the primary concerns that prompted the alert.*

35. The total length of the line from the tap on the HV transformer bushing to the air switch located on a support structure adjacent to the GSU is approximately 20'. The plant has been in operation for over 23 years and during the construction period the utility engineering department was involved with and approved the installation. Can we just take measurements and attest that we are in compliance?

*NERC is not prescribing exactly how an entity should validate the conditions. You will need to determine if your approach validates that the conditions under which the line was originally design match with a reasonable tolerance those actual in-field conditions.*

36. ANSI Standard A300 Part 7 IVM and NERC Standard FAC-003-1 pertain to Transmission Vegetation Program guidelines. What are the standards Generator Owners can follow for OHL generator ties?

*NERC cannot prescribe in this instance those reference materials other than to refer you to the contents within your facility ratings methodology for determining ratings.*

### **Other**

37. If Results-Based Standards are the goal of NERC, how do you justify this approach in the absence of actual experience of insufficient reliability from this cause?

*Actual experience indicates numerous instances of discrepancies when assessments have been performed.*

### **Priority**

38. How are "High", "Medium" and "Low" priority facilities defined?



*There are suggested criteria in the Gerry Cauley letter, but each entity should determine what its priorities are based on impact to reliability. NERC and the Regional Entities will review for reasonableness.*

## **Process**

39. Will NERC provide a formal acknowledgement or response to each submittal? If so in what time frame?

*NERC will not individually provide a response. However, in the NERC Alerts system, the entity will identify that its approved response has been submitted by the updated change in state on the entity's alert screen.*

40. After the initial submission (January 18th), will there be a response to the Registered Entity if the approach is deemed inadequate by NERC? Will the approach be formally evaluated? If so, how? What criteria will NERC/others use to determine if the adequacy of an operator's determination or if their methodology is "susceptible to these conditions"?

*NERC and the Regional Entities will collaborate to review the reasonableness of the assessment plan and engage the entity if particular concerns are identified. This guidance is in the process of being developed.*

41. How do entities submit future assessment reports and mitigation plans, if any, in December of 2011, 2012 & 2013, along with subsequent updates?

*NERC will provide further guidance on reporting expectations in the first quarter 2011.*

42. If an entity discovers an anomaly during the assessment, should the entity self-report then, and at each subsequent discrepancy discovered? Or just submit one self-report and mitigation plan that would cover any future discrepancies discovered during the overall response to this alert?

*If an entity identifies a condition for which a self-report is believed necessary, the entity should submit the self-report in a fashion that preserves the ability to add additional occurrences and mitigation strategies to the same report as the need arises, which would be filed on a periodic basis. NERC will provide further guidance on this issue in early 2011.*

43. Why wasn't a formal data request used in lieu of a NERC Alert?

*The core of the alert is the recommended action to assess and mitigate issues on the system. It is not to merely collect data. Had that been the intent, NERC would have employed its Section 1600 data gathering protocol in its Rules of Procedure.*

44. What evidence does NERC expect to receive to demonstrate that the assessment has been completed?

*NERC will reply on the entity reports that are required at the conclusion of 2011, 2012, and 2013 as evidence of completion.*

45. What level of review did FERC provide to this alert?

*NERC forwarded the draft of the alert to FERC and Canadian regulatory authorities as required per its Rules of Procedure prior to issuance. In addition, senior level NERC and FERC staff also discussed the alert and the expectations therein. Gerry Cauley also engaged in direct dialogue with the FERC Commissioners regarding the alert.*

46. The Facility Ratings Recommendation Questionnaire is no longer available as an attachment in the NERC Alert. Are there plans to make this questionnaire available again or are there other plans in the works for a new questionnaire?

*No. The questionnaire was replaced with a series of survey questions within the NERC Alerts system. The questions are the same as were provided in the questionnaire. This modified approach will permit NERC a much more efficient processing of the data once the response date is reached.*

## **Remediation**

47. With respect to remediation, is the one-year period from the date of the field identification, or the date the assessment report is submitted?

*The remediation timeframe is from the date of field identification.*

48. If an entity assesses their entire system by December, 2011, how long would they have to remediate issues they find? The new deadlines appear to suggest a one year time to fix all issues?

*The expectations for remediation would be consistent with the prioritization of the facilities as contemplated in the alert. However, in the case described where the entire assessment was completed in the first year, remediation would be expected over the next three years using the prioritized facilities list. That is, high priority facilities would be expected to be addressed in the first year from identification, medium priority in the next year, and so on.*

49. Is there a timeline for correcting the rating in the interim to match the field conditions until the permanent correction is in place? How involved will the Reliability Coordinator be in determining appropriate mitigation measures?



*There is no defined timeline for developing an interim strategy. However, NERC expects that each Reliability Coordinator would assess the overall impact of identified issues within its footprint and provide insight to the owning entity as to the urgency of mitigating the issue, and in helping identify an interim strategy. This approach recognizes that the issues have evolved over many, many years and NERC's intent is not for entities to make impulsive decisions that will ultimately detract from maintaining overall reliability, such as globally reducing line ratings for all noted discrepancies.*

50. Does an entity need to derate a line that doesn't meet the clearance requirements in the interim or just mitigate the issue in one year?

*NERC is not recommending a specific interim strategy to address issues, but is recommending that the issues be mitigated within one year from identification.*

51. If an entity finds discrepancy on a 138 kV line and decides to permanently derate the line because line loadings do not justify the cost to remedy back to the initial design rating, is this acceptable?

*This is an entity determination. NERC does not have an opinion on the appropriateness of this general approach to address specific issues.*

52. Will dynamic rating be an acceptable mitigation strategy?

*NERC has no opinion on the application of dynamic ratings to address specific issues. This is a decision of the entity.*

### **Response Timeframe**

53. Is it correct that the date to respond to the NERC Alert has been moved from December 15, 2010 to January 18, 2011?

*Correct.*

### **Response Expectations**

54. Will NERC prescribe a format they would like for plan submittals in January?

*No. NERC has established the survey contained in the alert system to capture entity responses that contemplates response format. NERC and the Regional Entities will review the response submittals and determine if further detail or clarity is needed. If an entity wishes to submit further detail, the alert system provides the ability to add supporting documents.*

55. For the assessment submittals due at the end of 2011, 2012, and 2013, what specific information must be provided (i.e., the number of transmission lines with discrepancies or

the new line rating, dates inspections performed, etc.)?

*NERC will provide guidance on assessment submittals in the first quarter 2011.*

56. What would happen if unforeseen circumstances (i.e. permitting process) delay a proposed mitigation effort beyond the timeline intended or beyond the one-year mitigation timeframe?

*An entity should file an updated mitigation plan with the Regional Entity for approval, indicating the nature of the issue and the expected timeframe for completion.*

57. With regard to the dates inspections were performed, to what level of detail does NERC expect the entity to provide?

*NERC anticipates the submittal would include the identifier for each transmission line and the date of the inspection.*

58. Is it expected that every NERC Alert that requires a submittal be approved by an officer?

*Yes. The two types of alerts requiring an officer-approved entity response are recommendations and essential actions.*

59. NPCC has developed a Criteria Document A-10 titled Classification of Bulk Power System Elements to identify the BPS elements within the interconnected NPCC Region. Entities within NPCC would expect to use these criteria to respond to the questions to provide the total number of BPS circuits on our system and the BPS circuit miles. Would this response be acceptable?

*Although NERC believes it would be valuable to assess all interconnected transmission facilities at 100 kV and above per the general bulk electric system definition, the scope of the facilities subject to the alert is established based upon the specific regional entity's definition of bulk electric system.*

60. Does the reporting entity need to consider only one of the three categories regarding facilities to include in the report?

*The intent is to include facilities that fall in any of the three categories.*

## **Scope**

61. Please clarify the scope of facilities to be considered subject to the alert. BES? Non-BES? Radial lines serving only load? Generator tie-line or interconnection facilities? Overhead lines? Underground lines?

*The alert is targeted to facilities that are considered bulk electric system facilities and to*

*entities who own such facilities as described in NERC's compliance registry as implemented by the regional entities. Radial lines serving only load are not included, but the generator tie lines for generator owners that are subject to the NERC standards are included. The focus on the alert is on overhead facilities. Although not in the scope of the alert, NERC suggests that assessing underground facility ratings based on actual as-built conditions would be beneficial, as well as reviewing load serving radial transmission facilities.*

62. The Alert did not go to DP/LSEs. What is the reporting requirement for DP/LSEs who are not TOs?

*There are no expectations for those not identified as alert recipients, such as DPs and LSEs.*

63. If facilities (lines) are excluded from FAC-003 because they are not 200 kV or above, and they are not identified as critical facilities by the Regional Entity, can they be excluded from this alert?

*No. All facilities that are considered part of the bulk electric system are in scope for the alert.*

64. If an entity does not own transmission lines but is a registered TO because it owns transmission equipment such as breakers, switches, transformers, etc., how would this alert apply?

*The entity would not have any expectations in this case, except to submit an approved response to that effect so NERC has record of your response.*

## **Standards**

65. FAC-008 does not require a methodology that requires field verification of ratings. The discussion in the first webinar suggests that Facility Rating Methodology should be modified to include a field verification of ratings. Doesn't NERC have to change the standard to require this field verification?

*Yes in order to require the field verification, the existing standards need to be modified. NERC is strongly recommending these actions at this time due to the pervasiveness of the issue.*

66. Shouldn't this issue be addressed primarily with regard to FAC-003 Requirement R1.2 that stipulates clearances, rather than tie it to FAC-008 and FAC-009?

*FAC-003 stipulates clearances only pertaining to vegetation. FAC-008 and FAC-009 pertain to establishing facility ratings using a documented methodology that identifies the various assumptions used in determining them. As such, these standards provide*

*comprehensive coverage to the issues that are the subject of the alert.*

67. The Recommendation requires entities to review their transmission facility ratings to confirm that any differences observed between design and actual field conditions are within the design tolerances as defined by the Registered Entity's Facility Ratings Methodology. Are the design tolerances determined and set by the entity that has developed their own Facility Ratings Methodology? Can you clarify the design tolerances, as this is currently not a requirement in NERC standard FAC-008 Facility Ratings Methodology?

*Design tolerances are established pursuant to the entity's facility ratings methodology, if included. These aspects may be considered in a future modification of the NERC standards.*

### **Technical Implementation**

68. What technologies other than LIDAR are to be considered acceptable technologies?

*NERC is not prescribing any particular technology including LIDAR. The intent is for the entity to perform an assessment of sufficient accuracy using methods selected by the entity to verify that in-field conditions reasonably match the assumptions upon which the line was rated.*

69. On new construction, will field construction data confirming setting depth, framing, dynamometer readings and weather conditions suffice in lieu of a post-energization field survey? If as-built drawings are created once construction is complete, which confirms that design clearances were met, is it necessary to survey/assess that line? Will a formal process have to be implemented to verify the as-built condition of newly-constructed lines?

*For new construction, NERC would expect a verification of in-field conditions versus design. If discrepancies were noted, a re-evaluation of the line rating would be appropriate.*

70. Sustainability has been mentioned several times on this webinar. How often will a periodic assessment of facilities be required, to identify topology changes, for example?

*In order to implement periodic assessments as a requirement, standards changes would be needed. However, NERC hopes that entities will incorporate methods to identify if topographical changes have occurred in the course of routine rights-of-way inspection activities and cycles.*

71. Is there any requirement or suggestion to include the cost and man hours needed to meet the plan, as part of the initial response submission?

*This information is not being requested at this time.*

72. As part of the FAC-003 TVMP, an entity reviews the 200 kV and above ROWs twice a year with fly-overs and, less than every 5 years, walks the rights-of-way. This is from a vegetation perspective but it is not a LIDAR effort. The FAC-003 TVMP works from the ground up not the conductor down (e.g. 10' vegetation above the ground easily meets clearance requirements for 200 kV and above). Anything of non-vegetation significance on the right-of-way would be noted during these assessments. We have already undertaken a rigorous LIDAR effort in an attempt to meet the original timeline. Is our FAC-003 TVMP approach adequate and LIDAR is not needed?

*Each entity needs to determine an appropriate approach to evaluate its system to ensure line ratings are properly established reflective of actual field conditions. NERC is not prescribing any one approach or even only one approach be employed to accomplish these objectives. Each entity is encouraged to develop a responsive prioritized strategy for all transmission facilities within the scope of the bulk electric system using whatever methods or practices deemed appropriate to verify in field conditions and their resultant impact on ratings, if any.*

73. Given the size difference between systems, would you consider a miles per year approach instead of a three year plan?

*NERC believes the approach as modified provides the flexibility intended by the question.*

74. We have some data can be used as evidence from a few years ago. How recently data do you consider the data is valid?

*The entity will need to determine "how valid" the data is and the likelihood of changes to in-field conditions that would render the data less useful. However, NERC would consider a recent assessment within the last five years as being reasonable provided the data provides the entity assurance that actual ratings are reflective of in-field conditions.*

75. Is a spot check of typical spans within a ruling span adequate? Or would you require checking every span?

*NERC is not prescribing a specific method or approach to accomplish the objectives of the alert. Each entity is encouraged to develop a responsive prioritized strategy for all transmission facilities within the scope of the bulk electric system using whatever methods or practices deemed appropriate to verify in field conditions and their resultant impact on ratings, if any.*

76. What is an acceptable risk in one's facility ratings? Different entities assume different wind speeds - which may or may not apply.

*These are factors and assumptions that are typically considered in an entity's facility ratings methodology. Each entity determines the thresholds appropriate for its facilities.*

77. Given the low incidence of line-to-ground contacts and the high cost to perform the assessment and mitigation, does NERC consider this to be an effective use of funds, on a cost-benefit basis, to enhance reliability?

*Based on the data NERC has reviewed, the number of discrepancies is estimated to be in the thousands. As such, NERC believes there is a basis for significant concern that warrants the assessments in order to ensure the continued reliability of the bulk power system.*

78. Using a correct sampling of a population, one can obtain 95% confidence in the results. Is this sufficient for purposes of the alert?

*NERC is not prescribing a specific method or approach to accomplish the objectives of the alert. Each entity is encouraged to develop a responsive prioritized strategy for all transmission facilities within the scope of the bulk electric system using whatever methods or practices deemed appropriate to verify in field conditions and their resultant impact on ratings, if any.*

79. Can an entity consider as-built drawings from the 1980's, with updates of those drawings as changes occur, and on-going vegetation management activities adequate and not require reevaluation of the lines?

*Potentially, if the entity believes it has adequately assessed and validated field conditions against the design assumptions that were used to determine the facility ratings.*

80. Do you expect field verification of the substation equipment end of the transmission line, including breakers, bus work, etc.?

*The main focus of the alert pertains to in-field clearances relative to the design assumptions used to rate the facilities, mainly on rights-of-ways. NERC is not prescribing the substation equipment as posited in the question.*

81. Does this recommendation include confirmation of all design parameters (e.g. structure location, ground clearances, conductor size, structure dimensions, structure material consistent with design, etc.)?

*No, the focus of the alert is on conductor clearances relative to in-field topography.*

82. If a TO can demonstrate that a circuit has been loaded to its rated value without any problem, is this evidence that the rating reflect current conditions?

*No as this approach does not address the primary issue that is the focus of the alert: determining if there are discrepancies in in-field conditions relative to the design assumptions within a reasonable tolerance that would lead to a potentially inaccurate line rating.*

83. If a TO has recently done a system wide thermal rate project and can document actual field conditions, can they so state on 1/18/11 questionnaire and be complete?

*Yes, if the entity believes it has adequately assessed and validated field conditions, and has addressed any issues that would lead to a discrepancy in established ratings.*

84. Our company has been systematically conducting aerial laser surveys (ALS) on our transmission lines. Following the ALS, a spatial model is developed to determine if conductor clearances meet the appropriate governing code. We are finding that about 75% of our initial "negatives" (or those failing to meet the governing code) are later determined by field evaluations to be incorrect. These field verifications are labor intensive and time consuming. At this point, we do not feel it is appropriate to deem a transmission line as not meeting the "as built" condition until this field verification is completed. What are NERC's thoughts?

*NERC believes that creating the list of potential discrepancies is important. In developing a mitigation strategy in the circumstances described, a necessary first step might be to verify the discrepancy before pursuing more intensive mitigation activities.*

85. Some transmission entities visit and view and evaluate each span of transmission line ROW of every year to evaluate each span. Is this not adequate to prove acceptance of design to present day field conditions?

*Yes, if the entity believes it has adequately assessed and validated field conditions, and has addressed any issues that would lead to a discrepancy in established ratings.*

86. Research has suggested that the core temperature of a conductor can be substantially hotter than the conductor's surface temperature which is used to determine the conductor's thermal sag. Will the new / upcoming (currently being updated) IEEE 738 methodology be used to determine actual sag values that may be substantially greater than earlier sag assessment methodology predicted?

*These aspects drive toward entity-specific assumptions for determining facility ratings and are outside the scope of this alert.*

87. What level of accuracy (in feet or %) does NERC consider adequate for actual clearance measurement, and subsequent modeling of clearance under maximum load conditions?

*These are assumptions that the entity determines for use in developing its facility ratings. NERC will not establish generic thresholds for acceptability.*

88. Will NERC ultimately seek formal certification of ratings based upon actual field conditions rather than as designed?



*If this were to be the desired outcome, NERC's standards would need to be modified using the industry development process.*



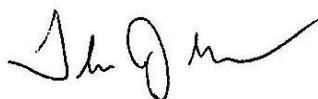
Ladies and Gentlemen:

On October 7, 2010, NERC issued an Alert to Industry entitled "Consideration of Actual Field Conditions in Determination of Facility Ratings." As a result, NERC received numerous questions about the alert and hosted two webinars. Then, on November 30, 2010, NERC posted a letter from President and CEO Gerry Cauley and an updated Alert, which can be found at: <http://www.nerc.com/page.php?cid=5|63>. Most recently NERC posted a Compliance Application Notice (CAN) on January 7, 2011, which can be found at: <http://www.nerc.com/page.php?cid=3|22|354>.

The attached Assessment Plan Review Criteria is used to provide guidance to Regional Entity staff in the review of assessment plans, to provide further assistance to the Owners in meeting the intent of the Recommendation, and to respond to those issues NERC stated it would provide further guidance for in its Question and Answer (Q&A) publication dated January 14, 2011.

Please interact with your members and provide any comments back to Roman Carter at [roman.carter@nerc.net](mailto:roman.carter@nerc.net) by close of business on May 10, 2011 in preparation for our webinar to discuss the changes on May 12, 2011.

Respectfully,



T. J. Galloway  
Senior Vice President and Chief Reliability Officer

cc: Mr. Gerry Cauley, Mr. Roman Carter, NERC

## NERC Facility Design, Connections, and Maintenance (FAC) Assessment Plan Review Criteria

April 26, 2011

The November 30, 2010 letter from Gerry Cauley provided guidance and information to Alert Recommendation recipients for performing the FAC assessments, including guidance and information regarding the prioritization of Transmission and Generation Owner's (Owners) facilities. This Assessment Plan Review Criteria is used to provide guidance to Regional Entity staff in review of assessment plans, provide further assistance to the Owners in meeting the intent of the Recommendation, and to respond to those issues NERC stated it would provide further guidance for in its Question and Answer (Q&A) publication dated January 14, 2011.

The majority of assessment plans reviewed are examples of what NERC considers to be good benchmarks and contains the appropriate level of content and detail. For example, those plans:

1. Provided detailed rationale for why its facilities were categorized as high, medium, or low.
2. Provided specific information on the type of technology being used in its assessment.
3. Included a timeline for completing the assessments which met the Recommendation's intent.

Regional Entity staff will contact those Owners that have already filed assessment plans with the appropriate content and level of detail to inform them of that determination. For those owners, this document is for informational purposes only.

For a portion of the assessment plans reviewed, Regional Entity staff has determined that assessment plans are not adequate to verify that the actual conditions conform to the Owner's design tolerances in accordance with its Facility Ratings Methodology or, that more information is required to make a determination. For example, some plans:

1. Did not prioritize facilities into high, medium, and low categories;
2. Provided no rationale for facility prioritization;
3. Did not provide details on how "as-built" construction conforms to the FAC ratings methodology;
4. Did not conform to the timelines given in the Recommendation

Regions will continue to review Owners' assessment plans, and where the Regional Entity (RE) believes the plans lack detail or are deficient, they will contact those Owners so that appropriate revisions can be made to the assessment plan. If any Owner believes its plan could be improved with the additional guidance, that Owner is encouraged to provide the RE with the appropriate revisions.

**Note:** *The prioritization categories below should not replace regular operational communication between Owners and the Transmission Operator (TOP) and Reliability Coordinator (RC) regarding imminent threats to reliable operation of the BES.*

**A. Recommended prioritization of Facilities Impacting Reliability**

For Owners who have submitted a deficient plan, the following criteria are being offered to advise an Owner regarding how to produce a sufficient plan. NERC recognizes that these criteria may not be appropriate for all entities and that individual plans should be developed (and evaluated by the Regional Entities) based on the characteristics and requirements of each individual system. Should an Owner determine that its prioritization of its transmission lines does not resemble the priority categories outlined below, but has an equal technically defensible risk-based prioritization approach, the Owner should consult with its RE and provide documentation to support its prioritization plan.

1) For **Transmission Owners**, recommendations for assessing BES transmission lines are as follows:

**High** (to be completed by end of 2011)

- *Transmission facilities that are components of an identified IROL or key transfer paths*
- *Transmission Facilities identified by the Owner as critical to reliability*
- *Heavily loaded Transmission lines and/or 500 kV and above in the Eastern and Western Interconnections*
- *Within NPCC, transmission lines defined as Bulk Power Supply (BPS) elements in accordance with NPCC Document A-10, "Classification of Bulk Power System Elements"*
- *Transmission lines of 345 kV in the ERCOT Region*

**Medium** (to be completed by end of 2012)

- *Transmission lines 230 kV – 499 kV in the Eastern and Western Interconnections*

- *Within NPCC, transmission lines 230 kV and higher which are not defined as BPS elements*
- *For the ERCOT Region, transmission lines 138 kV originating from stations containing 345/138 kV auto transformers or generation facilities with a name plate rating exceeding 450 MW*

**Low** (to be completed by end of 2013)

- *Transmission lines below 230 kV in the Eastern and Western Interconnections*
- *Within NPCC, transmission lines 115 kV and higher which are not defined as BPS elements*
- *For the ERCOT Region, transmission lines 138 kV or lower not meeting the “medium” criteria listed above*

2) For **Generator Owners** , recommendations for assessing generator tie-lines are as follows:

**High** (to be completed by end of 2011)

- *Units specified as “must run” for reliability or for BES voltage support*
- *Units specifically designated as part of a Special Protection System/Remedial Action Scheme for automated runback or ramp-up*
- *Units specifically identified as part of a documented plan for mitigating an IROL violation*
- Blackstart Resources identified in the Transmission Operator's restoration plan

**B. It is recommended that each Assessment performed by the Owner be detailed enough to confirm the following applicable information:**

- Conductor-to-conductor and conductor distance to objects (including ground clearance) occupying rights-of-way meet minimum clearance requirements of design
- Considered ambient conditions
- Considered operating limitations

**C. Owner Update Spreadsheet**

NERC is requesting each Owner provide semi-annual updates on the work performed to complete their assessment plans. The updates for their high priority transmission lines are due to the RE by July 15, 2011 and January 15, 2012. The updates for the medium priority transmission lines are due July 15, 2012 and

January 15, 2013. Finally, for the low priority transmission lines, the updates are due July 15, 2013 and January 14, 2014.

**Note:** A Discrepancy is when the Owner's assessment is not adequate to verify that the actual conditions conform to the Owner's design tolerances in accordance with its Facility Ratings Methodology and results in a derating of the line.

**D. What an Owner is recommended to do when a discrepancy is discovered**

If an Owner identifies a condition or conditions it believes is a discrepancy, NERC recommends that the Owner report the discrepancy to its Reliability Coordinator (RC), Transmission Operator (TOP), and the Planning Authority (PA) at the time of the discrepancy. NERC recommends that the Owner include the details of the condition causing the discrepancy (ies) in its next semi-annual Owner update. Should the Owner determine another condition at a later date that it believes is a discrepancy, the Owner again needs to report that condition to its RC, TOP, and the PA at the time of the discrepancy and again include the details of the condition causing the discrepancy (ies) in its next semi-annual update.

**E. Level of detail NERC recommends for inspection dates and identifiers**

NERC recommends that the Owner record the dates when inspections are being performed and be able to identify each transmission line and generator by a unique identifier, such as the NERC SDX common name. When a discrepancy does occur and is reported to its RC, TOP and the PA, NERC recommends that the Owner's facility also refer to the unique identifier, such as the SDX common name, in both the report and in the next Owner Update .

**F. Recommended Technologies**

Each Owner is recommended to utilize technologies that adequately address the Recommendation to confirm that any differences observed between design and actual field conditions are within design tolerances as defined by the Owner's Facility Ratings Methodology. While Light Detection and Ranging (LIDAR) with Power Line Systems – Computer Aided Design and Drafting (PLS-CADD) technology are appropriate and acceptable, these particular technologies are not required. Other alternative technologies can be utilized to confirm that design and actual field conditions are within each Owner's design tolerances such as:

- PS Guard Wide Area Monitoring System- ABB
- Sagometer – EPRI
- Thermal Line Monitor - LDIC GmbH
- Dynamic Line Rating System - Smarter Grid Solutions
- Power Line Sensor - Protura

## Event Analysis Process Improvements

### Action Required

None

### Background

One of the ERO's strategic goals is to promote and facilitate reliability improvement through event causal analysis and the open sharing of technical findings from event analysis reports with the industry.

Tom Galloway, senior vice president and chief reliability officer, will discuss how NERC is planning to meet this need while still respecting concerns regarding confidentiality, compliance enforcement, and critical energy infrastructure information protection. Mr. Galloway will provide a status report on the industry's reception of NERC's updated Event Analysis (EA) Process, which will enter the second phase of its field test in early May.

This update will include discussion of the Events Analysis Working Group (EAWG) efforts since May 2010 to revise the process, specific benefits expected, and important next steps. Aspects of this discussion will include:

#### EA Process Revision Background

- Focus on ERO as "learning" organization
  - Determine / correct event specific causes
  - Share lessons broadly
- Better understand risk, address actions accordingly
- Clarify process, deliverables, roles
- First draft 10/25/10 – Field Trial I
- Second draft 5/2/11 – Field Trial II to start 5/2/11 (**Attachment 1**)

#### Goals / Objectives

- Promoting bulk power system (BPS) reliability
- Developing a Reliability Excellence Culture
- Collaboration (NERC, Regions, Entities)
- Being a Learning Organization

#### Key Ingredients

- Identify what transpired – sequence of events
- Understand the cause of events
- Identify and ensure timely implementation of corrective actions
- Develop and disseminate valuable lessons learned to the industry to avoid repeat events
- Develop the capability to integrate risk analysis into the event analysis process

### Specific Phase II Changes

- Two webinars to introduce, others to communicate status
- Some event category reassignments
- Event notification - minimal data (24 hrs)
- Lower tier (Cat 1) events primarily closed to trend
- Cat 2 and above events
  - Data hold as standard action
  - Cause analysis
  - Compliance evaluations
- Lessons learned throughput improvements
- Periodic trend analysis
- Effective and timely sharing of event related data
  - Various forms
  - Constraints related to data sensitivity

### Next Steps

- Phase 2 Field Trial – 5/2/11
  - Three month run (nominal)
  - Accrue / address improvement opportunities
  - Issue another (final) revision by 10/1/11
- Enabling RoP changes – November 2011 BOT



# NERC

NORTH AMERICAN ELECTRIC  
RELIABILITY CORPORATION

## Electric Reliability Organization Event Analysis Process

Phase 2 Field Test Draft  
May 2, 2011

to ensure  
the reliability of the  
bulk power system



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# Section 1 — Goals of the Event Analysis Program

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## **Promoting Reliability**

The principal goal of the Electric Reliability Organization (ERO) is to promote the reliability of the bulk power system (BPS) in North America. This goal is directly supported by evaluating BPS events, undertaking appropriate levels of analysis to determine the causes of the events, promptly assuring tracking of corrective actions to prevent recurrence, and providing lessons learned to the industry. The event analysis process also provides valuable input for training and education, reliability trend analysis efforts and reliability standards development, all of which support continued reliability improvement.

## **Developing a Culture of Reliability Excellence**

Through the event analysis program, the ERO strives to develop a culture of reliability excellence that promotes and rewards aggressive self-critical review and analysis of operations, planning, and critical infrastructure protection processes. This self-critical focus must be ongoing, and the industry must recognize that registered entities are linked together by their individual and collective performances. This focus is the root of understanding the underlying cause of events and avoiding similar or repeated events through the timely identification and correction of event causes and through the sharing of lessons learned.

## **Collaboration**

Successful event analysis depends on a collaborative approach in which registered entities, Regional Entities and NERC work together to achieve a common goal. The process requires clarity, certainty and consistent adherence to reliability principles by BPS owners, operators and users that perform a wide array of reliability functions.

## **Being a Learning Organization**

As a learning organization, event analysis serves an integral function of providing insight and guidance by identifying and disseminating valuable information to owners, operators and users of the BPS who enable improved and more reliable operation. As such, event analysis is one of the pillars of a strong ERO.

## Section 2 — Philosophy and Key Ingredients of the ERO Event Analysis Program

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The ERO enterprise-wide event analysis program is based on the recognition that BPS system events that occur, or have the potential to occur, have varying levels of significance. The manner in which registered entities, Regional Entities and NERC evaluate and process these events is intended to reflect the significance of the event and/or specific system conditions germane to the reliability of the BPS and the circumstances involved.

The key ingredients of an effective event analysis program are to:

- Identify what transpired – sequence of events
- Understand the cause of events
- Identify and ensure timely implementation of corrective actions or evaluation of recommendations
- Develop and disseminate valuable lessons learned to the industry to enhance operational performance and avoid repeat events
- Develop the capability to integrate risk analysis into the event analysis process
- Share key results to facilitate enhancements in and support of NERC programs and initiatives (e.g., performance metrics, standards, compliance monitoring and enforcement, training and education, etc.)

The underlying characteristics that form a comprehensive and successful event analysis program are:

- Emphasis on a bottom-up approach in which registered entities serve in the primary role, taking first steps in analysis, development of lessons learned, self-identification of recommendations, and self-mitigation of reliability issues
- Appropriate Regional Entity and NERC review and oversight of registered entity event analysis results
- Emphasis directed toward proactive improvement of BPS reliability
- Clarity and certainty about what system events are relevant to analyze and to what level
- Clarity and certainty about event analysis roles, responsibilities, and expectations for respective entities, including target timeframes for completing certain actions
- Prioritization of events affecting reliability or potential vulnerabilities to the reliability of the BPS— detailed analysis for significant events, concise reviews for minor events, and a compliance self-assessment
- Timely development and dissemination of valuable lessons learned to the industry, resulting in real reliability improvement
- Proper confidentiality of data and information maintained at all times by all parties
- Tracking and timely reporting of events and event analysis trends

## Section 3 — Purpose of the Event Analysis Process Document

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The purpose of the event analysis process document is to provide a clear and concise description of the analysis process structure. This structure includes event identification, categorization, reporting and analysis processes. Once the causal factors of these events are identified, any significant lessons learned will also be shared with the industry so that actions may be taken to minimize the possibility of similar events occurring.

This document is not intended to be an all-inclusive checklist or procedure applicable to all possible events. It does, however, describe a defined and repeatable process for identifying BPS events that warrant a further level of analysis. The document also establishes clear roles, responsibilities and expectations for registered entities, Regional Entities and NERC in regard to the event analysis process.

The event analysis process document also aims to promote consistency, comparability, flexibility, and timeliness among the various existing event analysis processes. The process detailed within provides registered entities guidance in determining which events need to be reported, as well as guidance regarding the extent of further analysis of specific events.

The appendices and references of this document contain valuable tools and templates to help identify, categorize, analyze and report on events. References to various cause analysis techniques are also included.

## Section 4 — ERO Event Analysis Process

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### **Situation Awareness**

As registered entities experience events on the BPS, personnel with planning and operations responsibilities across the system need to be notified immediately. In addition, Regional Entities and NERC need to receive timely notification of any events or disturbances.

Section 1000 of the NERC Rules of Procedure, Situation Awareness, identifies NERC's responsibility for monitoring the condition of the BPS and for providing leadership and assistance for responding to events. To accomplish this task, NERC Situation Awareness staff monitors various tools and communications to identify events and unusual occurrences. Also, Registered Entities should notify Regional Entities and NERC to fulfill the Situation Awareness requirements as soon as possible when events occur. Event information is shared with NERC event analysis staff as the event analysis process begins.

### **Event Reporting**

Registered entities are required to report the occurrence of defined BPS disturbances and unusual occurrences to the applicable Regional Entity and NERC in accordance with various NERC and Regional reliability standards and other requirements, including but not limited to: EOP-002, EOP-004, TOP-007, CIP-001 and CIP-008. Each of these standards specifies timeframes for initial and final reports. The expectations for reporting additional information on such events do not relieve the registered entity from the reporting requirements per the aforementioned standards.

Information on certain system events or system reliability vulnerabilities learned from reported system events will also be communicated via Electricity Sector – Information Sharing and Analysis Center (ES-ISAC) messages, Department of Homeland Security Industrial Control Systems – Cyber Emergency Response Team (DHS ICS-CERT) Portal messages, Geomagnetic Disturbance (GMD) Alerts, etc. If the information provided through any of these sources or the reports required by the standards referenced above is insufficient in providing a complete understanding of the nature and extent of the event or potential vulnerability, the Regional Entity or NERC may request additional details, a Brief Report, or an event analysis report (EAR) from the involved registered entities.

NERC and the Regional Entities are cognizant of the effort of the registered entities to deal with system events and also meet the reporting expectations of the event analysis process. To this end, registered entities need to provide the necessary support personnel to assist system operators in completing the necessary event reports in a timely manner.

The EARs should not withhold information due to issues of confidentiality or CEII-protected information. Since the ultimate goal for NERC is BPS reliability, EARs should be configured so as to provide information valuable to others in the industry on a timely basis.

## **Required Reports**

The registered entity should provide notification of an event within 24 hours of its occurrence. Part A of **Appendix A** identifies the requirements for notification. Depending on the category of the event, registered entities may need to complete a more extensive Brief Report. Registered entities are requested to use the Brief Report template provided in **Appendix A** as a guideline for reporting the event to its applicable Regional Entity and NERC. The template may also be used for less significant events. In some cases, a revised or updated Brief Report may need to be submitted as additional information is learned about an event or questions are raised by the Regional Entity or NERC. In those cases, the registered entity should indicate this in any subsequent event report.

For a more significant event, an EAR is required, and the topics in the **Appendix A** template can be used as a guideline for its layout. An EAR begins with a scope of work and proposed schedule for the analysis developed by the registered entity and the Regional Entity.

## **Lessons Learned from Events**

Lessons learned as a result of an event analysis should be shared with the industry as soon as possible. The EAWG has developed a process for reviewing and posting lessons learned that have been identified in the event analysis process. Proposed lessons learned should be drafted by a registered entity utilizing the template in **Appendix D** and should be submitted to the applicable Regional Entity. The lessons learned should be detailed enough to be of value to others and should not contain data or information that is deemed confidential. Lessons learned are reviewed by the EAWG and by NERC staff for completeness and appropriateness prior to posting.

The steps for processing a lesson learned are as follows:

1. Registered entity and applicable Regional Entity will work together to prepare lesson learned using the template in **Appendix D**.
2. Registered entity and applicable Regional Entity will redact the lesson learned to remove all indication of the entity involved in the event and any other event details that are confidential.
3. Regional Entity will securely transfer the draft lesson learned to NERC.
4. Regional Entity will notify NERC staff that the lesson learned has been transferred.
5. NERC staff will review lesson learned.
6. NERC staff will add lesson learned to master list, prioritize lessons learned and identify common themes.
7. NERC staff will distribute priority draft lessons learned to EAWG for discussion on their next conference call.
8. Regional Entity that submitted the lesson learned or NERC staff will lead the EAWG discussion/review.
9. Regional Entity or NERC will make edits based on EAWG input.
10. Regional Entity will send lesson learned to the applicable registered entity for review, if needed, based on changes made.
11. NERC will post the lesson learned on the NERC web site and send a notification email to industry.

## **Lessons Learned from Other Events**

In normal operations, events may occur on the transmission system that do not meet the reporting thresholds of the defined event categories but may yield lessons of value to the industry. These lessons learned can include the adoption of unique operating procedures, the identification of generic equipment problems, or the need for enhanced personnel training. In such cases, an EAR would not be required, but the event analysis program encourages registered entities to share with their Regional Entity any potential lessons learned that could be useful to others in the industry and work with the Regional Entity and NERC to develop them for dissemination.

## **Report Types and Expected Levels of Analysis**

- **Notification** — prepared by impacted registered entities within 24 hours, sent to NERC and the applicable Regional Entity. The actual notification may come from a variety of sources such as, but not limited to EOP-004, OE-417, ES-ISAC report or **Appendix A**, Part A.
- **Brief Report** — prepared by impacted registered entities, sent to the applicable Regional Entity for review and sent to NERC. The Brief Report includes items identified in **Appendix A**, Parts A and B.
- **EAR** — prepared by the impacted entity, a group of impacted entities, or an event analysis team as defined in the EA process. Addresses what happened and why. The EAR is sent to the applicable Regional Entities for review and then sent to NERC.

Timeframes for the various reports are found in **Table 1** at the end of the section.

The following will be used to determine the level of analysis to be conducted:

- **Category 1** — Notification followed by a Brief Report. (Normally there is no follow-up anticipated for category 1 reports unless requested by the applicable Regional Entity).
- **Categories 2 and 3** — A notification followed by a Brief Report and an EAR prepared by the registered entity(ies) and follow-up as directed by the applicable Regional Entity.
- **Categories 4 and 5** — A notification followed by a Brief Report and an EAR developed by an event analysis team led by the Regional Entity or NERC.

## **Categorizing Events**

The registered entity is expected to work with the applicable Regional Entity to categorize events according to the event categories defined in **Appendix B**. The event categories are intended to allow the registered entity and Regional Entity to quickly and unambiguously identify the event thresholds.

The categories listed in **Appendix B** do not cover all possible events related to CIP, EMS loss of functionality, or loss of BPS “visibility” that could occur. To the extent that such events occur, their analyses would be discussed with the affected registered entity, appropriate Regional Entity and NERC.

## **Event Analysis Coordination**

Registered entities are expected to perform the event analysis. Coordination of the analysis becomes more complicated for events that involve a broader geographic area, involve multiple registered entities, or include a complex set of facts and circumstances.

Registered entities that reside in two Regional Entity footprints should notify both Regional Entities of an event. Following the notification, the two Regional Entities will determine which

one will coordinate the remaining steps of the event analysis process. When multiple registered entities are involved in or affected by an event, they should collaborate with the Regional Entity to determine if it is appropriate for each entity to prepare a report or for the entities to work together to prepare a single report.

### **Details of the Event Analysis Process**

#### **Category 1 Events**

Following notification, registered entities are expected to provide a Brief Report for Category 1 events. An EAR will not be required for most Category 1 events, unless requested by the applicable Regional Entity. A compliance self-assessment is encouraged.

In addition, the registered entity will provide to the applicable Regional Entity a draft of any suggested lessons learned associated with the event that may be applicable to the industry as well as recommendations that apply only to the affected registered entity, within the timeframes established in **Table 1**.

#### **Category 2 and 3 Events**

Following notification, registered entities are expected to provide a Brief Report (**Appendix A** format) followed by an EAR. A compliance self-assessment is required.

The registered entity should discuss the event with the applicable Regional Entity and agree on an event category, a level of analysis, a timeline for completion of the EAR, and any requirement for draft or preliminary reports as soon as possible following the occurrence of the event. The event analysis should have a level of detail and target timeframe commensurate with the nature and scope of the event.

**Note on Data Hold:** Registered entities should capture relevant data for the events in Category 2 or higher. Registered entities should expect a Data Hold letter specific to each event from the applicable Regional Entity. (See sample in **Appendix H**.) Copies of these requests will be made available to NERC.

It has been recognized that there may be considerable differences in the levels of analysis required for events that fall into Category 2 versus those that fall into Category 3, as well as differences for different types of events. The registered entity's analysis should reflect these differences and the planned level of analysis commensurate with the nature and scope of the particular event. The Regional Entity may make suggestions to the registered entity for an expansion or contraction of the event analysis effort.

The registered entity will provide its EAR to the applicable Regional Entity within the target timeframe unless otherwise agreed to by the Regional Entity. The registered entity will also be expected to respond to follow-up questions from the Regional Entity and NERC within a mutually agreeable timeframe. Preliminary and interim reports are encouraged. If the timeline for the completion of the EAR exceeds 30 days from the date of the event, draft reports need to be provided to the Regional Entity every 30 days.

The registered entity will maintain close communication with the Regional Entity during the development of its EAR, and the Regional Entity will follow the registered entity's progress.



Upon receipt of the completed EAR, the Regional Entity will review the report for thoroughness and completeness of analysis. If additional information is required, the Regional Entity will make that request, with a specified deadline, and inform NERC. If the Regional Entity is satisfied with the EAR and NERC has no further questions, the Regional Entity may close the analysis.

In addition to the EAR, the registered entity will provide to the applicable Regional Entity a draft of any suggested lessons learned associated with the event within 15 business days of the occurrence of the event for Category 2 events and within 20 business days for Category 3 events.

### **Category 4 and 5 Events**

**The expectations for Category 2 and 3 will also apply to Categories 4 and 5.** The first step following the occurrence of a Category 4 or Category 5 event is a conference call involving the affected registered entities, applicable Regional Entities and NERC to discuss the event and how the event analysis should proceed. In most cases, the analysis of Category 4 and 5 events will be conducted by an event analysis team led by the applicable Regional Entity or NERC. The decision on the composition of the event analysis team, the team lead, the information needed from affected registered entities, and the required scope of the analysis will be discussed and agreed to by the affected registered entities, applicable Regional Entities and NERC staff.

An Event Evaluation Checklist (**Appendix C**) is provided to assist in making a determination of what to include in an EAR. For example, the team can determine if the “Contributing Factor” caused the event, made the event worse or hindered restoration efforts. The Regional Entity(ies) and NERC will collaborate on the request for information from the affected registered entities. **Appendix C** originally comes from the NERC Blackout and Disturbance Response Procedures. These procedures became effective October 18, 2007. This information can be used to help guide and manage the analysis and reporting of disturbances.

For multi-entity events within a Region, the Regional Entity will generally coordinate or facilitate the event analysis, with participation by NERC. The Regional Entity will close the analysis with the agreement of NERC. For multi-Regional events, either the Regional Entity or NERC will generally coordinate or facilitate the event analysis, with participation by all the applicable Regional Entities and registered entities. NERC will close the analysis with the agreement of the Regional Entities.

As specified in the ERO Rules of Procedure, Section 807.e, the NERC president will determine whether any event warrants analysis at the NERC level. Regional Entities may also request NERC to elevate any analysis to the NERC level. Regardless of whether a Regional Entity or NERC is leading the analysis team, registered entities would be expected to actively participate in the analysis of the event and in the preparation of their respective portions of the final EAR.

The target timeframe for completion of EARs for Category 4 and 5 events will vary with the nature and extent of the event. Timelines for preliminary or draft reports will be established by the event analysis team, the applicable Regional Entities and NERC.

### **All Categories**

In the Brief Report or EAR, registered entities are encouraged to include one-line diagrams, other diagrams or other representations of the facility(ies) involved in the event, if applicable and helpful in enhancing the understanding of what happened in the event. Such diagrams may be

marked CEII if necessary, and will be treated accordingly. Special provisions have been made to transmit CEII-marked documents.

Final EARs should address corrective actions or recommendations to each contributing or “root” cause and also document what went well during or after an event in addition to what did not. This is a key part of a continuous learning and improvement program.

### **Event Closure**

Following the receipt of a final Brief Report, NERC and the Regional Entity will close the event within the timeframes established in **Table 1** unless additional information or analysis is requested of the registered entity.

Following the receipt of a final EAR, NERC and the Regional Entity will close the event within the timeframes established in **Table 1** unless additional information or analysis is requested of the registered entity.

### **Terms Used**

**Draft Lessons Learned**—A lesson learned during the analysis of an event, prepared by impacted registered entities in cooperation with the Regional Entity or NERC Event Analysis Team in the format identified, finalized and issued by NERC. **Appendix D**—prepared in parallel with EAR and finalized and issued by NERC.

**Data Hold**—As Registered Entities begin to analyze events, they must retain all data and information relative to the event in order to perform the detailed analysis. Regional Entities will formally send a Data Hold Retention Notice (**Appendix H**) for events in Category 2 or higher. Data holds will have an end date corresponding to the closing of the event or a timeframe identified in the request from the Regional Entity for the data hold.

**Corrective Actions or Recommendations**—An event analysis may include corrective actions or recommendations for registered entities to prevent recurrence of the event. These recommendations will be identified in the Brief Report or the EAR and completion of the corrective actions and evaluation or resolution of recommendations will be monitored by the Regional Entity.

**Appendix E** provides a summary of roles, responsibilities, and expectations for event reporting and analysis, and **Appendix F** provides a registered entity process checklist.

**Table 1** (below) provides the target timeframes for completion of Brief Reports, draft lessons learned, compliance self-assessments, EARs, and Event Analysis closure.

**Table 1 — Target Timeframes for Completion of Brief Reports, Draft Lessons Learned, Compliance Self-Assessments, and EARs<sup>1</sup>**

<b>Event Category</b>	<b>Brief Report</b>	<b>Draft Lessons Learned</b>	<b>EAR</b>	<b>Compliance Self-Assessment</b>	<b>Close Event Analysis</b>
1	Draft within five business days, sent to applicable Regional Entity for review. Final report within 10 days.	Within 15 business days	Not required	Encouraged (submittal not required)	10 business days following receipt of Brief Report
2	Draft within five business days, sent to applicable Regional Entity for review. Final report within 10 days.	Within 30 business days	30 business days	Initial (list of standards/requirements being reviewed) within 20 business days  Final within 60 business days after Brief Report	30 business days following receipt of EAR
3	Draft within five business days, sent to applicable Regional Entity for review. Final report within 10 days.	Within 30 business days	60 business days	Initial (list of standards/requirements being reviewed) within 20 business days  Final within 90 business days after Brief Report	30 business days following receipt of EAR
4	Draft within five business days, sent to applicable Regional Entity for review. Final report within 10 days.	Within 60 business days	120 business days	Initial (list of standards/requirements being reviewed) within 20 business days  Final within 150 business days after Brief Report	60 business days following receipt of EAR
5	Draft within five business days, sent to applicable Regional Entity for review. Final report within 10 days.	Within 60 business days	120 business days	Initial (list of standards/requirements being reviewed) within 20 business days  Final within 150 business days after Brief Report	60 business days following receipt of EAR

<sup>1</sup> All timeframes are subject to extension to accommodate special circumstances with agreement of the applicable Regional Entity.

## Section 5 — Event Analysis Interface with Compliance

Registered entities are expected to conduct a rigorous self-analysis of events. Prompt correction of identified causes, support for developing industry lessons learned, and performing a detailed compliance self-assessment are integral parts of the entire event analysis process and lead to the development of a strong culture of reliability. As part of this process, registered entities making a good faith effort to self-identify and self-report possible violations stemming from their event analyses will receive credit in any enforcement action. If further analysis by the Regional Entity or NERC reveals other possible violations, the registered entity will still be given credit for its cooperation in the process.

Registered entities should establish a liaison between their own internal event analysis and compliance functions as part of the event analysis process. This will provide a clearer understanding of the event from both an operational and a compliance standpoint, and it will facilitate a thorough standards review by the registered entity with possible feedback to the standards process and compliance self-assessment. This will also assure that the data required to do a complete and accurate event analysis is the same data that is used for the compliance self-assessment, resulting in the prompt self-reporting of possible violations through the established Compliance Monitoring and Enforcement Program processes.

Regional Entities are also encouraged to establish an appropriate liaison between their event analyses and compliance functions to facilitate sharing of event analysis results and minimize or avoid duplication of data and information requests and analyses.

Registered entities are expected to perform a thorough compliance analysis and to develop a compliance self-assessment report proportional to the severity of the event/risk to the BPS for categorized events in which there could be a gap between actual system or human performance and the requirements of NERC or regional standards. Compliance self-assessment reports are encouraged for all events in Category 1 and above and are requested to be submitted to the Regional Entity compliance liaison for Category 2 and above.

Compliance self-assessments should include:

- A list of all applicable NERC or Regional Reliability Standards and/or specific requirements potentially implicated by the event
- A written narrative/conclusion by the registered entity that compliance to the implicated reliability standards occurred
- A self-report of any possible violations through the existing Compliance Monitoring and Enforcement Program procedures associated with said event(s), with notification that they were discovered as a result of participating in the ERO event analysis program and completing the compliance self-assessment. (A suggested Compliance Analysis Template is included in Appendix G of this process for this purpose.)

If the registered entity is fully cooperative and timely in its self-analysis and identification of corrective actions, development of any lessons learned, and self-reporting of possible violations, the registered entity will be afforded significant credit during any possible enforcement phase of the Compliance Monitoring and Enforcement Program. Completed compliance self-assessment reports and related information are requested to be submitted to the Regional Entity compliance liaison for Category 2 and above.

## Section 6 — Confidentiality Considerations

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Certain data and information gathered during the course of an event analysis may need to be labeled CONFIDENTIAL and protected from disclosure beyond the event analysis team if the registered entity providing the data and information, the Regional Entity or NERC believe it to be Critical Energy Infrastructure Information (CEII) or commercially sensitive information. See Section 1500 of the NERC Rules of Procedure for further details on the definition and protection of “Confidential Information.”

Portions of draft and final EARs may also be subject to confidentiality restrictions as warranted. However, every effort should be made to make as much of these reports available to the industry as possible in order to promote the dissemination of lessons learned from events.

The rights and responsibilities of all entities participating in an event analysis or receiving a draft or final EAR will be specified in signed confidentiality agreements, if necessary, and in the foreword of draft and final reports.

Special procedures may need to be implemented in the case of CIP issues related to an event.

Data and information provided to the Regional Entity and/or NERC for analysis of a cross-border event will be maintained separately for U.S. and Canadian entities and only shared with governmental authorities for the jurisdiction within which the entities operate, consistent with applicable memorandums of understanding (MOUs) or other agreements.

## Section 7 — Event Analysis Trends

One of the by-products of the event analysis program is the identification of trends in the number, magnitude and frequency of events, and their associated causes, such as human error, relay coordination, protection system misoperations, etc. The information provided in event reports and EARS, in conjunction with other databases (TADS, GADS, Metric and Benchmarking Database, etc.) will be used to track and identify trends in BPS events.

Several teams continuously gather and analyze data that pertains to specific areas of the electric utility business. These teams are moving toward an integrated approach to analyzing data, assessing trends and communicating the results to the industry. Regions, regional entities and NERC in collaboration might prevent an underlying trend from growing and creating a much bigger power system event.

The following is a visual perspective representing the ERO's integration of risk concepts, assessments and tools from the Critical Infrastructure Protection, Standards Development, Reliability Assessments and Performance Analysis (RAPA) program, Compliance and Event Analysis Working Group (EAWG).

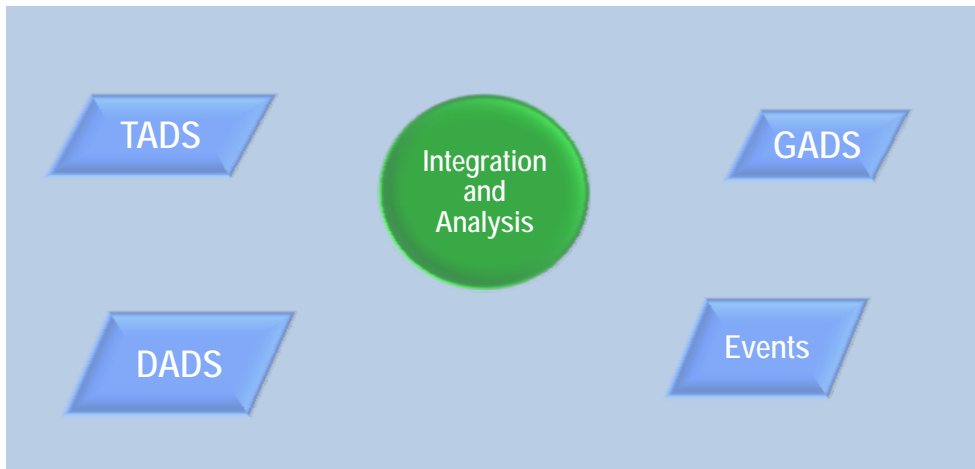


## **The Future Vision**

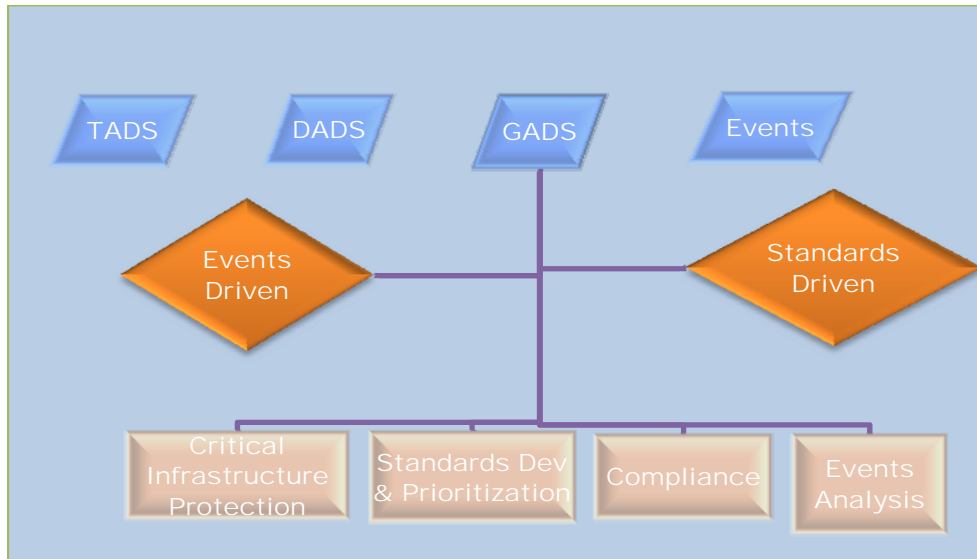
With this information and by working together, the registered entities, Regional Entities and NERC will be able to:

- Communicate the effectiveness of reliability improvement programs
- Provide an integrated view of risk
- Establish quantitative measures for determining achievement of the qualitative reliability goals
- Estimate effectiveness of risk reduction and/or mitigation strategies
- Identify trends and lessons learned
- Support industry analysis of root causes
- Prioritize Standards and Compliance activities

The diagrams below depict the necessary integrations of data and systems and demonstrate the intended direction of the ERO.







Over the next few years, several teams (e.g. EAWG, RMWG, SDT, Risk Framework, etc.) will work toward gathering data and publishing reports. The reports will discuss ways to measure and report BPS and equipment performance. They will also:

- Show how unifying existing GADS, TADS, DADS, events and related systems will help create an integrated view of the utility system operations
- Refine and implement risk assessment tools
- Identify areas of highest risk to reliability
- Reveal risk basis for standards and compliance programs
- Provide event-driven risk curves
- Identify reliability indicator trends
- Identify compliance performance measures
- Recommend standard changes and project prioritization

## Section 8 — Appendices and Other Suggested References

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Appendix A — Brief Report Template

Appendix B — Event Categories and Levels of Analysis [August 20, 2010 DRAFT]

Appendix C — Event Analysis Scope Template

Appendix D — Lessons Learned Template

Appendix E — Summary of Roles, Responsibilities and Expectations for Event Reporting and Analysis

Appendix F — Registered Entity Process Checklist

Appendix G — Compliance Analysis Template

Appendix H — Data Retention Hold Notice

### **Other References**

NERC Blackout and Disturbance Analysis Objectives, Analysis Approach, Schedule, and Status  
– Attachment D from Appendix 8 of NERC Rules of Procedure

## Appendix A – Event Reporting Template Instructions

### **Within 24 hours of the event:**

Submit Part A (Notification) if:

- (1) The event meets one of the Categories in **Appendix B** of the ERO Event Analysis Process, and
- (2) Other means of notification of the event have not been submitted as required by OE-417, EOP-004, ES-ISAC, DOE, CIP, etc.

Such Notifications shall be submitted to the appropriate Event Analysis contact at NERC (NERCSA@nerc.net) and the respective Regional Entity.

**Reported Event:** Provide a title that will be used to further identify the event. The title should include the date of the event (e.g. YYYYMMDD, Entity name, substation name)

### **Within five business days of the event:**

Submit Part B (Brief Report) using the previously submitted Part A (with any updates as needed) to the respective Regional Entity. The Regional Entity will collaborate with the registered entity to provide a Brief Report within ten (10) business days of the event to NERC.

The business day count starts on the next business day **after** the event.

**Submittal Date:** Should be updated with every Brief Report update.

**Brief Description (3):** It is expected that a Notification submittal will be shorter than a Brief Report submittal.

**Questions 6 -11:** If the event did involve generation, frequency, transmission facilities, and/or load question (6 – 11), may be left blank.

**Generation Tripped Off-line (6):** Provide a total MW loss and the names of the units that tripped off-line due to the event.

**Restoration Time (11):** Provide the times that affected transmission, generation, and/or were restored.

**Sequence of Events (12):** The sequence of events should provide a timeline of the events that took place leading up to and through the event.

**Narrative (15):** This section should expand on the brief description that was submitted in Part A, providing more detail as needed to more clearly describe the event.

## Reporting Template

### Part A (Notification)

(To be submitted to the Regional Entity and NERC within 24 hours of event – if not provided by other means as described in the instructions)

#### Reported Event:

**Region:**  
**Submittal Date:**

1. **Entity Name:**
2. **Date and Start Time of Disturbance:**
  - a. Date:
  - b. Time: (24-hour format)
  - c. Time Zone EST/EDT
3. **Brief description of event:**

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### Part B (Brief Report)

(To be submitted to the Regional Entity within five business days of event.)

**Status (initial, interim, final):**

4. **Proposed Event Categorization (e.g. 1a, 2b, 3c):**
5. **Name of Contact Person:**
  - a. E-mail Address:
  - b. Telephone Number (xxx-xxx-xxxx):
6. **Generation Tripped Off-line**

MW Total:

List Units Tripped:
7. **Frequency**
  - a. Just prior to disturbance (Hz):
  - b. Immediately following disturbance (Hz MAX):
  - c. Immediately following disturbance (Hz MIN):
8. **List transmission facilities (lines, transformers, buses, etc.) tripped and locked out. (Specify voltage level of each facility listed and extent of equipment damage, if any.)**
9. **Demand Interrupted (MW):** Firm: Interruptible:
10. **Number of Affected Customers:** Firm: Interruptible:

11. **Restoration Time from Time of Event (24-hour format)**
  - a. Transmission:
  - b. Generation:
  - c. Demand:
  
12. **Sequence of Events:**
  
13. **Identify contributing causes of the to the extent known:**
  
14. **Identify any protection system misoperations to the extent known:**
  
15. **Narrative**
  
16. **If you supply a one-line diagram, explain that one-line diagram.**
  
17. **Identify the significance and duration of any monitoring and control events, such as loss of BPS visibility, loss of data links, etc.**

## Appendix B — Event Categories

### Operating Reliability Event Categories

Operating reliability events are those events that are deemed to have significantly impacted the reliable operation of interconnected system. These events are divided into five categories that account for their differing impacts on the system and help determine the level of analysis that is warranted. **The highest category that characterizes an event shall be used.** The lists below are intended to provide examples of the types of events that fall into each category. For events not covered below, the impacted registered entity, in conjunction with the Regional Entity and NERC, will determine the categorization.

#### Category 1: An event resulting in one or more of the following:

- a. Unintended loss of three or more BPS elements caused by common mode failure. For example,
  - i. The loss of a combination of generators, transmission lines, auto transformers and buses.
  - ii. The loss of an entire generation station of three or more generators (aggregate generation of 500 MW to 999 MW); combined cycle units are represented as 1 unit.
- b. Intended and controlled system separation by the proper operation of a Special Protection System Scheme (SPS) / Remedial Action Scheme (RAS) in Alberta from the Western Interconnection, New Brunswick or Florida from the Eastern Interconnection.
- c. Failure or misoperation of SPS/RAS.
- d. System-wide voltage reduction of 3% or more.
- e. Unintended BPS system separation resulting in an island of 100 MW to 999 MW.
- f. Unplanned evacuation from a control center facility with BPS SCADA functionality for 30 minutes or more.

#### Category 2: An event resulting in one or more of the following:

- a. Complete loss of all BPS control center voice communication system(s) for 30 minutes or more.
- b. Complete loss of SCADA, control or monitoring functionality for 30 minutes or more.
- c. Voltage excursions equal to or greater than 10% lasting more than five minutes.
- d. Loss of off-site power (LOOP) to a nuclear generating station.
- e. Unintended system separation resulting in an island of 1,000 MW to 4,999 MW.
- f. Unintended loss of 300MW or more of firm load for more than 15 minutes.
- g. Violation of an Interconnection Reliability Operating Limit (IROL) for more than 30 minutes.

#### Category 3: An event resulting in one or more of the following:

- a. The loss of load or generation of 2,000 MW or more in the Eastern Interconnection or Western Interconnection, or 1,000 MW or more in the ERCOT or Québec Interconnections.

- b. Unintended system separation resulting in an island of 5,000 MW to 10,000 MW.
- c. Unintended system separation resulting in an island of Florida from the Eastern Interconnection.

**Category 4: An event resulting in one or more of the following:**

- a. The loss of load or generation from 5,001 MW to 9,999 MW.
- b. Unintended system separation resulting in an island of more than 10,000 MW (with the exception of Florida as described in Category 3c).

**Category 5: An event resulting in one or more of the following:**

- a. The loss of load of 10,000 MW or more.
- b. The loss of generation of 10,000 MW or more.

## Appendix C — Event Analysis Scope Template

Contributing Factor	Explanation of Contributing Factor	Contributing Factor in Causing The Event, Increasing Its Severity, Or Hindering Restoration? (Yes or No)	Explanation
1. Power System Facilities	The existence of sufficient physical facilities to provide a reliable BPS.		
2. Relaying Systems	Detection of bulk power supply parameters that are outside normal operating limits and activation of protective devices to prevent or limit damage to the system. (UFLS/UVLS)		
3. System Monitoring, Operating Control And Communication Facilities	Ability of dispatch and control facilities to monitor and control operation of the bulk power supply system. Adequacy of communication facilities to provide information within and between entities.		
4. Operating Personnel Performance	Ability of system personnel to communicate appropriately and react properly to unanticipated circumstances that require prompt decisive action.		
5. Operational Planning	Study of near-term operating conditions. Application of results to system operation.		
6. System Reserve and Generation Response	Ability of generation or load reduction equipment to maintain or restore system frequency and tie-line flows to acceptable levels following a system disturbance.		
7. Preventive Maintenance	A program of routine inspections and tests to detect and correct potential equipment failures.		
8. Load Relief	The intentional disconnection of customer load in a planned and systematic manner or restoration of the balance between available power supply and demand.		
9. Restoration	Orderly and effective procedures to quickly re-establish customer service and restore the bulk power supply system to a reliable condition.		
10. Special Protection Systems (or Remedial Action Schemes)	An automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other		



	than and/or in addition to the isolation of faulted components to maintain system reliability.		
11. System Planning	Comprehensive planning work using appropriate planning criteria to provide a reliable bulk power supply system.		
12. Reliability Coordinator action	Directives, actions, or procedures of the Reliability Coordinator(s).		
13. Cyber security	Ability of personnel to react properly to unanticipated circumstances that require prompt decisive action.		
14. Other	Any other factor not listed above which was significant in causing the disturbance, making the disturbance more severe or adversely affecting restoration.		

## Appendix D — Lessons Learned

### Information for Completing a Lessons Learned Report

The headings definitions for the Lessons Learned Report are as follows:

**Primary Interest Groups** – The “Primary Interest Groups” heading is to identify those NERC registered entities which could possibly benefit from the information contained in the Lessons Learned report. NERC registered entities are defined per the “NERC Reliability Functional Model Function Definitions and Responsible Entities” document, which can be found on the NERC web site. (Example: Transmission Owner, Generator Owner, Load Serving Entity, etc.)

**Problem Statement** – The “Problem Statement” heading is to provide a short descriptive narrative of the problem that occurred. Usually this can be defined in one sentence, but the purpose of the problem statement is to explain the problem so that the reader is able to easily determine if the problem is of interest without having to go further into the report.

**Details** – The “Details” heading is to provide a concise narrative of the what happened in the event, the end result of the event, the findings of the analysis of the event, corrective actions taken and any other pertinent information that will provide the reader information that could be used in applying the lessons learned to their responsibilities.

**Corrective Actions** – Defines what was learned from the analysis of the event. The lessons learned should be a list of changes the entity incorporated to ensure the event would not happen again. Some examples of items identified are changes in procedures, changes in training programs, equipment replacement, equipment testing changes, etc.

**Lessons Learned** – Knowledge and experience – positive or negative – derived from actual incidents or events as well observations and historical studies of operations, training and exercises.

## Lessons Learned Template

# Lesson Learned — DRAFT TITLE

### Primary Interest Groups

### Problem Statement

### Details

### Corrective Actions

### Lesson Learned

For more information please contact:

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Director of Event Analysis and Investigation

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*This document is designed to convey lessons learned from NERC's various activities. It is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing reliability standards. Compliance will continue to be determined based on language in the NERC Reliability Standards as they may be amended from time to time. Implementation of this lesson learned is not a substitute for compliance with requirements in NERC's Reliability Standards.*

## Appendix E — Summary of Roles, Responsibilities and Expectations for Event Reporting and Analysis

<b>Category 1 Events</b>			
<b>Entity</b>	<b>Brief Report</b>	<b>Event Analysis Report (EAR)</b>	<b>Lessons Learned</b>
<b>Registered Entity</b>	<p>Ensure notification was provided to the Regional Entity and NERC.</p> <p>Provide initial report to Regional Entity and NERC in accordance with requirements specified in applicable NERC standards.</p> <p>Ensure content of report is consistent with Event Reporting Template included in <b>Appendix A</b>.</p> <p>Provide Brief Report in five business days or less.</p>		<p>Provide Draft of suggested lessons learned to Regional Entity within 15 business days of event occurrence.</p>
<b>Regional Entity</b>	<p>Request additional event information from registered entity as needed.</p> <p>Send Brief Report to NERC within 10 business days of the event.</p> <p>Notify registered entity that event analysis is closed unless NERC has additional questions.</p>		<p>Review draft lessons learned from registered entity. Request additional information as deemed necessary.</p> <p>Work with registered entity and NERC to prepare final lessons learned for review by EAWG.</p>
<b>NERC</b>	<p>Coordinate with Regional Entity to determine whether additional event report information from registered entity should be provided.</p> <p>Raise additional questions before Regional Entity closes event analysis</p>		<p>Work with registered entity and Regional Entity to prepare final lessons learned for review by EAWG.</p> <p>Disseminate final lessons learned to industry.</p>

## Appendix E — Summary of Roles, Responsibilities, and Expectations for Event Reporting and Analysis

Category 2 and 3 Events			
Entity	Brief Report	Event Analysis Report (EAR)	Lessons Learned
<b>Registered Entity</b>	<p>Ensure notification was provided to the Regional Entity.</p> <p>Provide initial event report to Regional Entity and NERC in accordance with requirements specified in applicable NERC standards.</p> <p>Ensure content of report is consistent with Event Report Template included in Appendix A.</p> <p>Provide Brief Report in five business days or less.</p>	<p>Hold data relevant to the event for 120 days unless notified by the Regional Entity.</p> <p>Provide EAR to Regional Entity within 30 business days for Category 2 event or 60 business days for Category 3 events. Registered Entity and Regional Entity should collaborate on the expectations for the report and any extensions to the due dates.</p>	<p>Provide draft of suggested lessons learned to Regional Entity within 30 business days of event occurrence.</p>
<b>Regional Entity (RE)</b>	<p>Request additional event information from registered entity as determined by Regional Entity or in collaboration with NERC.</p> <p>Send Data Hold Retention Notice to entity.</p> <p>Send Brief Report to NERC within 10 business days of the event.</p>	<p>Request EAR if not initiated by registered entity. Specify deadline.</p> <p>Follow progress of event analysis and report preparation with Entity.</p> <p>Review EAR for sufficiency and request additional analysis or information as deemed necessary. Specify deadline and inform NERC.</p> <p>Notify registered entity that event analysis is closed unless NERC has additional questions.</p>	<p>Review draft lessons learned from registered entity. Request additional information as deemed necessary.</p> <p>Work with registered entity and NERC to prepare final lesson learned for review by EAWG.</p>
<b>NERC</b>	<p>Coordinate with Regional Entity to determine if additional event information is needed.</p>	<p>Review final version of EAR, and provide comments to Regional Entity Before Regional Entity closes event analysis.</p>	<p>Work with registered entity and Regional Entity to prepare final lessons learned for review by EAWG.</p> <p>Disseminate final lesson learned to industry.</p>

## Appendix E — Summary of Roles, Responsibilities and Expectations for Event Reporting and Analysis

<b>Category 4 and 5 Events</b>			
<b>Entity</b>	<b>Brief Report</b>	<b>Event Analysis Report (EAR)</b>	<b>Lessons Learned</b>
<b>Registered Entity</b>	<p>Ensure notification was provided to the Regional Entity.</p> <p>Provide initial event report to Regional Entity and NERC in accordance with requirements specified in applicable NERC standards.</p> <p>Ensure content of report is consistent with Event Report Template included in <b>Appendix A</b>.</p> <p>Provide Brief Report in five business days or less.</p>	<p>Hold data relevant to the event for 120 days unless notified by the Regional Entity.</p> <p>Participate in event analysis as directed by Regional Entity and NERC.</p>	<p>Provide draft of suggested lessons learned to Regional Entity within 60 business days of event.</p>
<b>Regional Entity (RE)</b>	<p>Request additional event information from registered entity as determined by Regional Entity or requested by NERC.</p> <p>Send Data Hold Retention Notice to entity.</p> <p>Send Brief Report to NERC within 10 business days of the event.</p>	<p>Conference call of affected registered entities, Regional Entities involved, and NERC within five business days of occurrence of event to discuss approach for conduct of event analysis and agreement on composition and lead for event analysis team.</p> <p>Collaborate with NERC on request for information from affected registered entities.</p> <p>Coordinate event analysis for multi-entity events within Regional Entity. (Category 4)</p> <p>Participate in multi-regional event analysis led by NERC. (Category 5)</p> <p>Follow progress of event analysis and report preparation.</p> <p>Notify registered entity that event analysis is closed with agreement of NERC for Category 4 events.</p>	<p>Review draft lessons learned from registered entity. Request additional information as deemed necessary.</p> <p>Work with registered entity and NERC to prepare final lessons learned for review by EAWG.</p>
<b>Category 4 and 5 Events</b>			
<b>NERC</b>	<p>Request Regional Entity to provide additional event report information from registered entity, as needed.</p>	<p>Conference call of affected registered entities, Regional Entities involved, and NERC within five business days of occurrence of event to discuss approach for conduct of event analysis and agreement on composition and lead for event</p>	<p>Work with registered entities and Regional Entity(s) to prepare final lessons learned for review by EAWG.</p> <p style="text-align: right;">31</p> <p>Disseminate final lessons learned to</p>

		<p>analysis team.</p> <p>Collaborate with Regional Entity(s) involved on request for information from affected registered entities.</p> <p>Participate in multi-entity events within Regional Entity, led by Regional Entity. (Category 4)</p> <p>Lead multi-regional event analyses when determined by NERC president. (Category 4 or 5)</p> <p>Notify registered entity that event analysis is closed for Category 5 events, with agreement of the applicable Regional Entities</p>	<p>industry.</p>
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## Appendix F — Registered Entity Process Checklist

1. Event occurs.
2. Ensure notification was provided to the Regional Entity and NERC within 24 hours.
3. Confer with Regional Entity to confirm event category AND analysis/reporting requirements.
4. **IF Category 1 THEN:**
  - a. **Brief Report:** Report in accordance with NERC or Regional Reliability Standards requirements or as otherwise requested by Regional Entity. Brief Report in five business days or less.
  - b. **Lessons Learned:** Draft of suggested lessons learned (if any) to Regional Entity within 15 business days of event occurrence.
  - c. **Compliance Review:** Initiate concurrently with Brief Report. Submittal of Compliance Review is not required for Category 1 events.
  - d. **Corrective Action Plan (or Recommendation):** If there are recommendations or corrective actions identified that will prevent recurrence, they should be included in the final Brief Report.
5. **IF Category 2 THEN:**
  - a. **Data Hold:** Capture data relevant to the event and hold for 120 days unless otherwise notified.
  - b. **Brief Report:** Report in accordance with NERC or Regional Reliability Standards requirements or as otherwise requested by Regional Entity. Brief Report in five business days or less.
  - c. **Event Analysis Report:** Initiate and submit report to Regional Entity within 30 business days (collaborate on content with Regional Entity).
  - d. **Lessons Learned:** Draft of suggested lessons learned to Regional Entity within 30 **business days** of event occurrence.
  - e. **Compliance Review:** Initiate concurrently with EAR; complete within 60 days after Brief Report.
  - f. **Corrective Action Plan (or Recommendation):** If there are recommendations or corrective actions identified that will prevent recurrence, they should be included in the final Brief Report.
6. **IF Category 3 THEN:**
  - a. **Data Hold: Capture data** relevant to the event and hold for 120 days unless otherwise notified.
  - b. **Brief Report:** Report in accordance with NERC or Regional Reliability Standards requirements or as otherwise requested by Regional Entity. Brief Report in five business days or less.
  - c. **Event Analysis Report:** Finalize report to Regional Entity within 60 business days of event occurrence (or by time agreed to with Regional Entity).
  - d. **Lessons Learned:** Draft of suggested lessons learned to Regional Entity within 30 business days of event occurrence.
  - e. **Compliance Review:** Initiate concurrently with EAR; provide list of standards/requirement being reviewed within 20 days; complete within 90 days after Brief Report.
  - f. **Corrective Action Plan (or Recommendation):** If there are recommendations or corrective actions identified that will prevent recurrence, they should be included in the final Brief Report.



**7. IF Category 4 THEN:**

- a. **Data Hold: Capture data** relevant to the event and hold for 120 days unless otherwise notified.
- b. **Brief Report:** Report in accordance with NERC or Regional Reliability Standards requirements or as otherwise requested by Regional Entity. Brief Report in five business days or less.
- c. **Event Analysis Report:** Finalize report to Regional Entity within 120 business days of event occurrence (or by time agreed to with Regional Entity).
- d. **Lessons Learned:** Draft of suggested lessons learned to Regional Entity within 60 business days of event occurrence.
- e. **Compliance Review:** Initiate concurrently with EAR; provide list of standards/requirement being reviewed within 20 days; complete within 150 days after Brief Report.
- f. **Corrective Action Plan (or Recommendation):** If there are recommendations or corrective actions identified that will prevent recurrence, they should be included in the final Brief Report.

**8. IF Category 5 THEN:**

- a. **Data Hold:** Capture data relevant to the event and hold for 120 days unless otherwise notified.
- b. **Brief Report:** Report in accordance with NERC or Regional Reliability Standards requirements or as otherwise requested by Regional Entity. Brief Report in five business days or less.
- c. **Event Analysis Report:** Finalize report to Regional Entity within 120 business days of event occurrence (or by time agreed to with Regional Entity).
- d. **Lessons Learned:** Draft of suggested lessons learned to Regional Entity within 60 business days of event occurrence.
- e. **Compliance Review:** Initiate concurrently with EAR; provide list of standards/requirement being reviewed within 20 days; complete within 150 business days after Brief Report.
- f. **Corrective Action Plan (or Recommendation):** If there are recommendations or corrective actions identified that will prevent recurrence, they should be included in the final Brief Report.

## Appendix G — Compliance Assessment Template

The registered entity’s compliance function is expected to perform an initial compliance assessment, concurrent with the registered entity’s event analysis process.

A systematic, methodical compliance assessment process might include the following steps:

1. Refer to the causes and contributing factors of the event as determined by the registered entity’s event analysis process.
2. Identify any applicable Reliability Standards requirement that may have been implicated by the causes and contributing factors of the event.
3. Develop conclusions after reviewing the facts and circumstances of the event that are relevant to step 2 above as they apply to the applicable Reliability Standards requirements.
4. Self-report any findings of non-compliance to the Regional Entity per the CMEP procedures.

### Sample Template for Compliance Assessment Summary

Event causes or contributing factors	Applicable NERC Reliability Standards	Details of Compliance Assessment Effort	Findings
Cause	AAA-000-0 Requirement 1	Identify the process used to assess compliance with this requirement.  Identify any evidence that demonstrates compliance.  Identify any evidence that suggests non-compliance.	Findings of possible violations should be identified.  If there are no findings of non-compliance, that should be noted.
	AAA-000-0 Requirement 2		
Contributing factor	BBB-000-0 Requirement 1		

### Category 1a Example

Event causes or contributing factors	Applicable NERC Reliability Standards	Details of Compliance Assessment Effort	Findings*
Equipment failure of a high side transformer– cleared along with two transmission lines.	<b>TOP-002-2a</b> <b>R6.</b> Each BA and TOP shall plan to meet unscheduled changes in system configuration and generation dispatch (at a minimum N-1 Contingency planning) in accordance with NERC, Regional Reliability Organization, sub-regional and local reliability requirements.	Established transfer limits were followed such that the event did not result in instability. The limit for operating across this internal interface is established in the RC.  “ <u>XYZ Interface All Lines In Stability Guide</u> ” (document provided)	No findings of non-compliance.*
Equipment failure of a high side transformer– cleared along with two transmission lines.	<b>TOP-002-2a</b> <b>R10.</b> Each Balancing Authority and Transmission Operator shall plan to meet all System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs).	No SOLs were violated. There are no IROLs associated with the loss of equipment in this event. See the specific guide referenced in the response to <b>TOP-002-2a R6</b> .	No findings of non-compliance.*
Equipment failure of a high side transformer– cleared along with two transmission lines.	<b>TOP-004-2</b> <b>R1.</b> Each TOP shall operate within the IROLs and SOLs. <b>R2.</b> Each TOP shall operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency.	The system was operated to remain within transfer limits across the “XYZ” internal interface established as a result of stability studies as delineated in the Transmission Operating Guide developed by RC. See the specific guide referenced in the response to <b>TOP-002-2a R6</b> .	No findings of non-compliance*
Equipment failure of a high side transformer– cleared along with two transmission lines.	<b>PRC-001</b> <b>R1.</b> Each TOP, BA and GOP shall be familiar with the purpose and limitations of protection system schemes applied in its area.	Both the RC and the TOPs are trained on the Transmission Operating Guides as well as relaying and SPSs on the BPS. Protection operated correctly and as planned.	No findings of non-compliance*
Equipment failure of a high side transformer– cleared along with two transmission lines.	<b>PRC-004</b> <b>R1.</b> The TOP and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity’s procedures.	System Protection engineers evaluated the relay operations and determined that all relaying operated correctly and as planned.	No findings of non-compliance*
Equipment failure of a high side transformer– cleared	<b>TOP-008</b> <b>R1.</b> The TOP experiencing or contributing to an IROL or SOL	R1 Operators used their EMS-based tools to ensure that there were no	No findings of non-compliance*

<p>along with two transmission lines.</p>	<p>violation shall take immediate steps to relieve the condition, which may include shedding firm load.</p> <p><b>R2.</b> Each Transmission Operator shall operate to prevent the likelihood that a disturbance, action, or inaction will result in an IROL or SOL violation in its area or another area of the Interconnection. In instances where there is a difference in derived operating limits, the TOP shall always operate the BPS to the most limiting parameter.</p> <p><b>R3.</b> The TOP shall disconnect the affected facility if the overload on a transmission facility or abnormal voltage or reactive condition persists and equipment is endangered. In doing so, the TOP shall notify its RC and all neighboring TOPs impacted by the disconnection prior to switching, if time permits, otherwise, immediately thereafter.</p> <p><b>R4.</b> The TOP shall have sufficient information and analysis tools to determine the cause(s) of SOL violations. This analysis shall be conducted in all operating timeframes. The TOP shall use the results of these analyses to immediately mitigate the SOL violation.</p>	<p>SOL/IROL violations.</p> <p>R2 by following the TOP Guides developed by RC, violations do not occur.</p> <p>R3 no conditions occurred that required disconnection.</p> <p>R4 Operators used their EMS-based tools to ensure that there were no SOL/IROL violations.</p>	
<p>Equipment failure of a high side transformer– cleared along with two transmission lines.</p>	<p><b>TOP-006</b></p> <p><b>R2.</b> Each RC, TOP and BA shall monitor applicable transmission line status, real and reactive power flows, voltage, load-tap-changer settings, and status of rotating and static reactive resources.</p> <p><b>R5</b> Each RC, TOP and BA shall use monitoring equipment to bring to the attention of operating personnel important deviations in operating conditions and to indicate, if appropriate, the need for corrective action.</p>	<p>The EMSs at both the RC and the TOP provide operators with the information needed to evaluate system conditions and notify operators when conditions are off normal. EMS system visibility and communications were not lost during this event.</p>	<p>No findings of non-compliance*</p>

			<p>*Findings as the outcome of a compliance self-assessment will result in either a statement of “No Findings” or that of “Possible Violation (PV).”</p> <p>Should the latter be the result, the entity will be given the opportunity to self-report the PV to the Regional Compliance Enforcement department, in accordance with the existing procedures set forth in the CMEP. In doing so, the entity self-reporting should inform the Regional Compliance Enforcement department that this has been done consistent with the event analysis process and the completion of a compliance self-assessment (<b>Appendix G</b>) to obtain the credit prescribed.</p>
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## Appendix H – Data Retention Hold Notice

**CONFIDENTIAL — NON-PUBLIC**

### **DATA RETENTION HOLD NOTICE**

**Subject:** [ ]

**Notice Date:** [DATE]

**Date of Event:** [DATE]

The [Name of Issuer] is reviewing the circumstances surrounding the [Description of Event] (Event).

Therefore, this letter serves as *official notice* to [Registered Entity Name] to preserve and retain and not discard or destroy any and all data or documentation pertaining to the Event.

- Documentation includes, but is not limited to: operator logs, recorded voice communications, e-mail and written correspondence, work orders, inspection records, patrol records, and any other documents, fault recorder records, data or other information that may be directly or indirectly related to the Event, including “Electronic Data.” In addition, documentation includes, but is not limited to e-mails and other forms of communication, including Electronic Data, from entity personnel, including management, that may be directly or indirectly related or relevant to the Event.
- Documentation includes, but is not limited to: Energy Management System (EMS) data with regards to system load, frequency, online and offline generation energy/capacity, reserve capacity, forecasted load, capacity study results, interchange schedules, Market Analyst Interface, SCADA, and any other documents, data or other information that may be directly or indirectly related to the Event.
- “Electronic Data” shall include, but not be limited to: all planning power system models, operational planning system models, text files (including word processing documents), spreadsheets, e-mail files and information concerning e-mail (including logs of e-mail history and usage, header information and “deleted” files), internet history files and preferences, graphical image format (GIF) files, databases, calendar and scheduling information, computer system activity logs, and all file fragments and backup files containing Electronic Data.

**[Registered Entity Name]** is required, upon request, to produce any requested data pursuant to Title 18 of the Code of Federal Regulations (CFR)<sup>2</sup> Part 39.

This Notice will be in effect for 120 calendar days from the date of issuance, unless extended by **[Issuer]**.

Please confirm by e-mail, within 24 hours of receipt, that you have received this message.

If you have any questions regarding this Notice and related requirements please contact me at any time using my contact information below.

Respectfully submitted,

**[Insert Signature]**

**[Insert Name]**

**[Insert Title and Contact Information]**

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<sup>2</sup> 18 CFR Part 39, Section 39.2 requires: (d) Each user, owner or operator of the Bulk-Power System within the United States (other than Alaska and Hawaii) shall provide the Commission, the Electric Reliability Organization and the applicable Regional Entity such information as is necessary to implement section 215 of the Federal Power Act as determined by the Commission and set out in the Rules of the Electric Reliability Organization and each applicable Regional Entity. The Electric Reliability Organization and each Regional Entity shall provide the Commission such information as is necessary to implement section 215 of the Federal Power Act.

# NERC

NORTH AMERICAN ELECTRIC  
RELIABILITY CORPORATION

## Electric Reliability Organization Event Analysis Process

Phase 2 Field Test Draft  
May 2, 2011

to ensure  
the reliability of the  
bulk power system



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# Section 1 — Goals of the Event Analysis Program

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## **Promoting Reliability**

The principal goal of the Electric Reliability Organization (ERO) is to promote the reliability of the bulk power system (BPS) in North America. This goal is directly supported by evaluating BPS events, undertaking appropriate levels of analysis to determine the causes of the events, promptly assuring tracking of corrective actions to prevent recurrence, and providing lessons learned to the industry. The event analysis process also provides valuable input for training and education, reliability trend analysis efforts and reliability standards development, all of which support continued reliability improvement.

## **Developing a Culture of Reliability Excellence**

Through the event analysis program, the ERO strives to develop a culture of reliability excellence that promotes and rewards aggressive self-critical review and analysis of operations, planning, and critical infrastructure protection processes. This self-critical focus must be ongoing, and the industry must recognize that registered entities are linked together by their individual and collective performances. This focus is the root of understanding the underlying cause of events and avoiding similar or repeated events through the timely identification and correction of event causes and through the sharing of lessons learned.

## **Collaboration**

Successful event analysis depends on a collaborative approach in which registered entities, Regional Entities and NERC work together to achieve a common goal. The process requires clarity, certainty and consistent adherence to reliability principles by BPS owners, operators and users that perform a wide array of reliability functions.

## **Being a Learning Organization**

As a learning organization, event analysis serves an integral function of providing insight and guidance by identifying and disseminating valuable information to owners, operators and users of the BPS who enable improved and more reliable operation. As such, event analysis is one of the pillars of a strong ERO.

## Section 2 — Philosophy and Key Ingredients of the ERO Event Analysis Program

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The ERO enterprise-wide event analysis program is based on the recognition that BPS system events that occur, or have the potential to occur, have varying levels of significance. The manner in which registered entities, Regional Entities and NERC evaluate and process these events is intended to reflect the significance of the event and/or specific system conditions germane to the reliability of the BPS and the circumstances involved.

The key ingredients of an effective event analysis program are to:

- Identify what transpired – sequence of events
- Understand the cause of events
- Identify and ensure timely implementation of corrective actions or evaluation of recommendations
- Develop and disseminate valuable lessons learned to the industry to enhance operational performance and avoid repeat events
- Develop the capability to integrate risk analysis into the event analysis process
- Share key results to facilitate enhancements in and support of NERC programs and initiatives (e.g., performance metrics, standards, compliance monitoring and enforcement, training and education, etc.)

The underlying characteristics that form a comprehensive and successful event analysis program are:

- Emphasis on a bottom-up approach in which registered entities serve in the primary role, taking first steps in analysis, development of lessons learned, self-identification of recommendations, and self-mitigation of reliability issues
- Appropriate Regional Entity and NERC review and oversight of registered entity event analysis results
- Emphasis directed toward proactive improvement of BPS reliability
- Clarity and certainty about what system events are relevant to analyze and to what level
- Clarity and certainty about event analysis roles, responsibilities, and expectations for respective entities, including target timeframes for completing certain actions
- Prioritization of events affecting reliability or potential vulnerabilities to the reliability of the BPS— detailed analysis for significant events, concise reviews for minor events, and a compliance self-assessment
- Timely development and dissemination of valuable lessons learned to the industry, resulting in real reliability improvement
- Proper confidentiality of data and information maintained at all times by all parties
- Tracking and timely reporting of events and event analysis trends

## Section 3 — Purpose of the Event Analysis Process Document

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The purpose of the event analysis process document is to provide a clear and concise description of the analysis process structure. This structure includes event identification, categorization, reporting and analysis processes. Once the causal factors of these events are identified, any significant lessons learned will also be shared with the industry so that actions may be taken to minimize the possibility of similar events occurring.

This document is not intended to be an all-inclusive checklist or procedure applicable to all possible events. It does, however, describe a defined and repeatable process for identifying BPS events that warrant a further level of analysis. The document also establishes clear roles, responsibilities and expectations for registered entities, Regional Entities and NERC in regard to the event analysis process.

The event analysis process document also aims to promote consistency, comparability, flexibility, and timeliness among the various existing event analysis processes. The process detailed within provides registered entities guidance in determining which events need to be reported, as well as guidance regarding the extent of further analysis of specific events.

The appendices and references of this document contain valuable tools and templates to help identify, categorize, analyze and report on events. References to various cause analysis techniques are also included.

## Section 4 — ERO Event Analysis Process

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### **Situation Awareness**

As registered entities experience events on the BPS, personnel with planning and operations responsibilities across the system need to be notified immediately. In addition, Regional Entities and NERC need to receive timely notification of any events or disturbances.

Section 1000 of the NERC Rules of Procedure, Situation Awareness, identifies NERC's responsibility for monitoring the condition of the BPS and for providing leadership and assistance for responding to events. To accomplish this task, NERC Situation Awareness staff monitors various tools and communications to identify events and unusual occurrences. Also, Registered Entities should notify Regional Entities and NERC to fulfill the Situation Awareness requirements as soon as possible when events occur. Event information is shared with NERC event analysis staff as the event analysis process begins.

### **Event Reporting**

Registered entities are required to report the occurrence of defined BPS disturbances and unusual occurrences to the applicable Regional Entity and NERC in accordance with various NERC and Regional reliability standards and other requirements, including but not limited to: EOP-002, EOP-004, TOP-007, CIP-001 and CIP-008. Each of these standards specifies timeframes for initial and final reports. The expectations for reporting additional information on such events do not relieve the registered entity from the reporting requirements per the aforementioned standards.

Information on certain system events or system reliability vulnerabilities learned from reported system events will also be communicated via Electricity Sector – Information Sharing and Analysis Center (ES-ISAC) messages, Department of Homeland Security Industrial Control Systems – Cyber Emergency Response Team (DHS ICS-CERT) Portal messages, Geomagnetic Disturbance (GMD) Alerts, etc. If the information provided through any of these sources or the reports required by the standards referenced above is insufficient in providing a complete understanding of the nature and extent of the event or potential vulnerability, the Regional Entity or NERC may request additional details, a Brief Report, or an event analysis report (EAR) from the involved registered entities.

NERC and the Regional Entities are cognizant of the effort of the registered entities to deal with system events and also meet the reporting expectations of the event analysis process. To this end, registered entities need to provide the necessary support personnel to assist system operators in completing the necessary event reports in a timely manner.

The EARs should not withhold information due to issues of confidentiality or CEII-protected information. Since the ultimate goal for NERC is BPS reliability, EARs should be configured so as to provide information valuable to others in the industry on a timely basis.

## **Required Reports**

The registered entity should provide notification of an event within 24 hours of its occurrence. Part A of **Appendix A** identifies the requirements for notification. Depending on the category of the event, registered entities may need to complete a more extensive Brief Report. Registered entities are requested to use the Brief Report template provided in **Appendix A** as a guideline for reporting the event to its applicable Regional Entity and NERC. The template may also be used for less significant events. In some cases, a revised or updated Brief Report may need to be submitted as additional information is learned about an event or questions are raised by the Regional Entity or NERC. In those cases, the registered entity should indicate this in any subsequent event report.

For a more significant event, an EAR is required, and the topics in the **Appendix A** template can be used as a guideline for its layout. An EAR begins with a scope of work and proposed schedule for the analysis developed by the registered entity and the Regional Entity.

## **Lessons Learned from Events**

Lessons learned as a result of an event analysis should be shared with the industry as soon as possible. The EAWG has developed a process for reviewing and posting lessons learned that have been identified in the event analysis process. Proposed lessons learned should be drafted by a registered entity utilizing the template in **Appendix D** and should be submitted to the applicable Regional Entity. The lessons learned should be detailed enough to be of value to others and should not contain data or information that is deemed confidential. Lessons learned are reviewed by the EAWG and by NERC staff for completeness and appropriateness prior to posting.

The steps for processing a lesson learned are as follows:

1. Registered entity and applicable Regional Entity will work together to prepare lesson learned using the template in **Appendix D**.
2. Registered entity and applicable Regional Entity will redact the lesson learned to remove all indication of the entity involved in the event and any other event details that are confidential.
3. Regional Entity will securely transfer the draft lesson learned to NERC.
4. Regional Entity will notify NERC staff that the lesson learned has been transferred.
5. NERC staff will review lesson learned.
6. NERC staff will add lesson learned to master list, prioritize lessons learned and identify common themes.
7. NERC staff will distribute priority draft lessons learned to EAWG for discussion on their next conference call.
8. Regional Entity that submitted the lesson learned or NERC staff will lead the EAWG discussion/review.
9. Regional Entity or NERC will make edits based on EAWG input.
10. Regional Entity will send lesson learned to the applicable registered entity for review, if needed, based on changes made.
11. NERC will post the lesson learned on the NERC web site and send a notification email to industry.

## **Lessons Learned from Other Events**

In normal operations, events may occur on the transmission system that do not meet the reporting thresholds of the defined event categories but may yield lessons of value to the industry. These lessons learned can include the adoption of unique operating procedures, the identification of generic equipment problems, or the need for enhanced personnel training. In such cases, an EAR would not be required, but the event analysis program encourages registered entities to share with their Regional Entity any potential lessons learned that could be useful to others in the industry and work with the Regional Entity and NERC to develop them for dissemination.

### **Report Types and Expected Levels of Analysis**

- **Notification** — prepared by impacted registered entities within 24 hours, sent to NERC and the applicable Regional Entity. The actual notification may come from a variety of sources such as, but not limited to EOP-004, OE-417, ES-ISAC report or **Appendix A**, Part A.
- **Brief Report** — prepared by impacted registered entities, sent to the applicable Regional Entity for review and sent to NERC. The Brief Report includes items identified in **Appendix A**, Parts A and B.
- **EAR** — prepared by the impacted entity, a group of impacted entities, or an event analysis team as defined in the EA process. Addresses what happened and why. The EAR is sent to the applicable Regional Entities for review and then sent to NERC.

Timeframes for the various reports are found in **Table 1** at the end of the section.

The following will be used to determine the level of analysis to be conducted:

- **Category 1** — Notification followed by a Brief Report. (Normally there is no follow-up anticipated for category 1 reports unless requested by the applicable Regional Entity).
- **Categories 2 and 3** — A notification followed by a Brief Report and an EAR prepared by the registered entity(ies) and follow-up as directed by the applicable Regional Entity.
- **Categories 4 and 5** — A notification followed by a Brief Report and an EAR developed by an event analysis team led by the Regional Entity or NERC.

### **Categorizing Events**

The registered entity is expected to work with the applicable Regional Entity to categorize events according to the event categories defined in **Appendix B**. The event categories are intended to allow the registered entity and Regional Entity to quickly and unambiguously identify the event thresholds.

The categories listed in **Appendix B** do not cover all possible events related to CIP, EMS loss of functionality, or loss of BPS “visibility” that could occur. To the extent that such events occur, their analyses would be discussed with the affected registered entity, appropriate Regional Entity and NERC.

### **Event Analysis Coordination**

Registered entities are expected to perform the event analysis. Coordination of the analysis becomes more complicated for events that involve a broader geographic area, involve multiple registered entities, or include a complex set of facts and circumstances.

Registered entities that reside in two Regional Entity footprints should notify both Regional Entities of an event. Following the notification, the two Regional Entities will determine which one will coordinate the remaining steps of the event analysis process. When multiple registered

entities are involved in or affected by an event, they should collaborate with the Regional Entity to determine if it is appropriate for each entity to prepare a report or for the entities to work together to prepare a single report.

### **Details of the Event Analysis Process**

#### **Category 1 Events**

Following notification, registered entities are expected to provide a Brief Report for Category 1 events. An EAR will not be required for most Category 1 events, unless requested by the applicable Regional Entity. A compliance self-assessment is encouraged.

In addition, the registered entity will provide to the applicable Regional Entity a draft of any suggested lessons learned associated with the event that may be applicable to the industry as well as recommendations that apply only to the affected registered entity, within the timeframes established in **Table 1**.

#### **Category 2 and 3 Events**

Following notification, registered entities are expected to provide a Brief Report (**Appendix A** format) followed by an EAR. A compliance self-assessment is required.

The registered entity should discuss the event with the applicable Regional Entity and agree on an event category, a level of analysis, a timeline for completion of the EAR, and any requirement for draft or preliminary reports as soon as possible following the occurrence of the event. The event analysis should have a level of detail and target timeframe commensurate with the nature and scope of the event.

**Note on Data Hold:** Registered entities should capture relevant data for the events in Category 2 or higher. Registered entities should expect a Data Hold letter specific to each event from the applicable Regional Entity. (See sample in **Appendix H**.) Copies of these requests will be made available to NERC.

It has been recognized that there may be considerable differences in the levels of analysis required for events that fall into Category 2 versus those that fall into Category 3, as well as differences for different types of events. The registered entity's analysis should reflect these differences and the planned level of analysis commensurate with the nature and scope of the particular event. The Regional Entity may make suggestions to the registered entity for an expansion or contraction of the event analysis effort.

The registered entity will provide its EAR to the applicable Regional Entity within the target timeframe unless otherwise agreed to by the Regional Entity. The registered entity will also be expected to respond to follow-up questions from the Regional Entity and NERC within a mutually agreeable timeframe. Preliminary and interim reports are encouraged. If the timeline for the completion of the EAR exceeds 30 days from the date of the event, draft reports need to be provided to the Regional Entity every 30 days.

The registered entity will maintain close communication with the Regional Entity during the development of its EAR, and the Regional Entity will follow the registered entity's progress.

Upon receipt of the completed EAR, the Regional Entity will review the report for thoroughness and completeness of analysis. If additional information is required, the Regional Entity will



make that request, with a specified deadline, and inform NERC. If the Regional Entity is satisfied with the EAR and NERC has no further questions, the Regional Entity may close the analysis.

In addition to the EAR, the registered entity will provide to the applicable Regional Entity a draft of any suggested lessons learned associated with the event within 15 business days of the occurrence of the event for Category 2 events and within 20 business days for Category 3 events.

### **Category 4 and 5 Events**

**The expectations for Category 2 and 3 will also apply to Categories 4 and 5.** The first step following the occurrence of a Category 4 or Category 5 event is a conference call involving the affected registered entities, applicable Regional Entities and NERC to discuss the event and how the event analysis should proceed. In most cases, the analysis of Category 4 and 5 events will be conducted by an event analysis team led by the applicable Regional Entity or NERC. The decision on the composition of the event analysis team, the team lead, the information needed from affected registered entities, and the required scope of the analysis will be discussed and agreed to by the affected registered entities, applicable Regional Entities and NERC staff.

An Event Evaluation Checklist (**Appendix C**) is provided to assist in making a determination of what to include in an EAR. For example, the team can determine if the “Contributing Factor” caused the event, made the event worse or hindered restoration efforts. The Regional Entity(ies) and NERC will collaborate on the request for information from the affected registered entities. **Appendix C** originally comes from the NERC Blackout and Disturbance Response Procedures. These procedures became effective October 18, 2007. This information can be used to help guide and manage the analysis and reporting of disturbances.

For multi-entity events within a Region, the Regional Entity will generally coordinate or facilitate the event analysis, with participation by NERC. The Regional Entity will close the analysis with the agreement of NERC. For multi-Regional events, either the Regional Entity or NERC will generally coordinate or facilitate the event analysis, with participation by all the applicable Regional Entities and registered entities. NERC will close the analysis with the agreement of the Regional Entities.

As specified in the ERO Rules of Procedure, Section 807.e, the NERC president will determine whether any event warrants analysis at the NERC level. Regional Entities may also request NERC to elevate any analysis to the NERC level. Regardless of whether a Regional Entity or NERC is leading the analysis team, registered entities would be expected to actively participate in the analysis of the event and in the preparation of their respective portions of the final EAR.

The target timeframe for completion of EARs for Category 4 and 5 events will vary with the nature and extent of the event. Timelines for preliminary or draft reports will be established by the event analysis team, the applicable Regional Entities and NERC.

### **All Categories**

In the Brief Report or EAR, registered entities are encouraged to include one-line diagrams, other diagrams or other representations of the facility(ies) involved in the event, if applicable and helpful in enhancing the understanding of what happened in the event. Such diagrams may be marked CEII if necessary, and will be treated accordingly. Special provisions have been made to transmit CEII-marked documents.

Final EARs should address corrective actions or recommendations to each contributing or “root” cause and also document what went well during or after an event in addition to what did not. This is a key part of a continuous learning and improvement program.

### **Event Closure**

Following the receipt of a final Brief Report, NERC and the Regional Entity will close the event within the timeframes established in **Table 1** unless additional information or analysis is requested of the registered entity.

Following the receipt of a final EAR, NERC and the Regional Entity will close the event within the timeframes established in **Table 1** unless additional information or analysis is requested of the registered entity.

### **Terms Used**

**Draft Lessons Learned**—A lesson learned during the analysis of an event, prepared by impacted registered entities in cooperation with the Regional Entity or NERC Event Analysis Team in the format identified, finalized and issued by NERC. **Appendix D**—prepared in parallel with EAR and finalized and issued by NERC.

**Data Hold**—As Registered Entities begin to analyze events, they must retain all data and information relative to the event in order to perform the detailed analysis. Regional Entities will formally send a Data Hold Retention Notice (**Appendix H**) for events in Category 2 or higher. Data holds will have an end date corresponding to the closing of the event or a timeframe identified in the request from the Regional Entity for the data hold.

**Corrective Actions or Recommendations**—An event analysis may include corrective actions or recommendations for registered entities to prevent recurrence of the event. These recommendations will be identified in the Brief Report or the EAR and completion of the corrective actions and evaluation or resolution of recommendations will be monitored by the Regional Entity.

**Appendix E** provides a summary of roles, responsibilities, and expectations for event reporting and analysis, and **Appendix F** provides a registered entity process checklist.

**Table 1** (below) provides the target timeframes for completion of Brief Reports, draft lessons learned, compliance self-assessments, EARs, and Event Analysis closure.

**Table 1 — Target Timeframes for Completion of Brief Reports, Draft Lessons Learned, Compliance Self-Assessments, and EARs<sup>1</sup>**

<b>Event Category</b>	<b>Brief Report</b>	<b>Draft Lessons Learned</b>	<b>EAR</b>	<b>Compliance Self-Assessment</b>	<b>Close Event Analysis</b>
1	Draft within five business days, sent to applicable Regional Entity for review. Final report within 10 days.	Within 15 business days	Not required	Encouraged (submittal not required)	10 business days following receipt of Brief Report
2	Draft within five business days, sent to applicable Regional Entity for review. Final report within 10 days.	Within 30 business days	30 business days	Initial (list of standards/requirements being reviewed) within 20 business days  Final within 60 business days after Brief Report	30 business days following receipt of EAR
3	Draft within five business days, sent to applicable Regional Entity for review. Final report within 10 days.	Within 30 business days	60 business days	Initial (list of standards/requirements being reviewed) within 20 business days  Final within 90 business days after Brief Report	30 business days following receipt of EAR
4	Draft within five business days, sent to applicable Regional Entity for review. Final report within 10 days.	Within 60 business days	120 business days	Initial (list of standards/requirements being reviewed) within 20 business days  Final within 150 business days after Brief Report	60 business days following receipt of EAR
5	Draft within five business days, sent to applicable Regional Entity for review. Final report within 10 days.	Within 60 business days	120 business days	Initial (list of standards/requirements being reviewed) within 20 business days  Final within 150 business days after Brief Report	60 business days following receipt of EAR

<sup>1</sup> All timeframes are subject to extension to accommodate special circumstances with agreement of the applicable Regional Entity.

## Section 5 — Event Analysis Interface with Compliance

Registered entities are expected to conduct a rigorous self-analysis of events. Prompt correction of identified causes, support for developing industry lessons learned, and performing a detailed compliance self-assessment are integral parts of the entire event analysis process and lead to the development of a strong culture of reliability. As part of this process, registered entities making a good faith effort to self-identify and self-report possible violations stemming from their event analyses will receive credit in any enforcement action. If further analysis by the Regional Entity or NERC reveals other possible violations, the registered entity will still be given credit for its cooperation in the process.

Registered entities should establish a liaison between their own internal event analysis and compliance functions as part of the event analysis process. This will provide a clearer understanding of the event from both an operational and a compliance standpoint, and it will facilitate a thorough standards review by the registered entity with possible feedback to the standards process and compliance self-assessment. This will also assure that the data required to do a complete and accurate event analysis is the same data that is used for the compliance self-assessment, resulting in the prompt self-reporting of possible violations through the established Compliance Monitoring and Enforcement Program processes.

Regional Entities are also encouraged to establish an appropriate liaison between their event analyses and compliance functions to facilitate sharing of event analysis results and minimize or avoid duplication of data and information requests and analyses.

Registered entities are expected to perform a thorough compliance analysis and to develop a compliance self-assessment report proportional to the severity of the event/risk to the BPS for categorized events in which there could be a gap between actual system or human performance and the requirements of NERC or regional standards. Compliance self-assessment reports are encouraged for all events in Category 1 and above and are requested to be submitted to the Regional Entity compliance liaison for Category 2 and above.

Compliance self-assessments should include:

- A list of all applicable NERC or Regional Reliability Standards and/or specific requirements potentially implicated by the event
- A written narrative/conclusion by the registered entity that compliance to the implicated reliability standards occurred
- A self-report of any possible violations through the existing Compliance Monitoring and Enforcement Program procedures associated with said event(s), with notification that they were discovered as a result of participating in the ERO event analysis program and completing the compliance self-assessment. (A suggested Compliance Analysis Template is included in Appendix G of this process for this purpose.)

If the registered entity is fully cooperative and timely in its self-analysis and identification of corrective actions, development of any lessons learned, and self-reporting of possible violations, the registered entity will be afforded significant credit during any possible enforcement phase of the Compliance Monitoring and Enforcement Program. Completed compliance self-assessment reports and related information are requested to be submitted to the Regional Entity compliance liaison for Category 2 and above.

## Section 6 — Confidentiality Considerations

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Certain data and information gathered during the course of an event analysis may need to be labeled CONFIDENTIAL and protected from disclosure beyond the event analysis team if the registered entity providing the data and information, the Regional Entity or NERC believe it to be Critical Energy Infrastructure Information (CEII) or commercially sensitive information. See Section 1500 of the NERC Rules of Procedure for further details on the definition and protection of “Confidential Information.”

Portions of draft and final EARs may also be subject to confidentiality restrictions as warranted. However, every effort should be made to make as much of these reports available to the industry as possible in order to promote the dissemination of lessons learned from events.

The rights and responsibilities of all entities participating in an event analysis or receiving a draft or final EAR will be specified in signed confidentiality agreements, if necessary, and in the foreword of draft and final reports.

Special procedures may need to be implemented in the case of CIP issues related to an event.

Data and information provided to the Regional Entity and/or NERC for analysis of a cross-border event will be maintained separately for U.S. and Canadian entities and only shared with governmental authorities for the jurisdiction within which the entities operate, consistent with applicable memorandums of understanding (MOUs) or other agreements.

## Section 7 — Event Analysis Trends

One of the by-products of the event analysis program is the identification of trends in the number, magnitude and frequency of events, and their associated causes, such as human error, relay coordination, protection system misoperations, etc. The information provided in event reports and EARS, in conjunction with other databases (TADS, GADS, Metric and Benchmarking Database, etc.) will be used to track and identify trends in BPS events.

Several teams continuously gather and analyze data that pertains to specific areas of the electric utility business. These teams are moving toward an integrated approach to analyzing data, assessing trends and communicating the results to the industry. Regions, regional entities and NERC in collaboration might prevent an underlying trend from growing and creating a much bigger power system event.

The following is a visual perspective representing the ERO's integration of risk concepts, assessments and tools from the Critical Infrastructure Protection, Standards Development, Reliability Assessments and Performance Analysis (RAPA) program, Compliance and Event Analysis Working Group (EAWG).

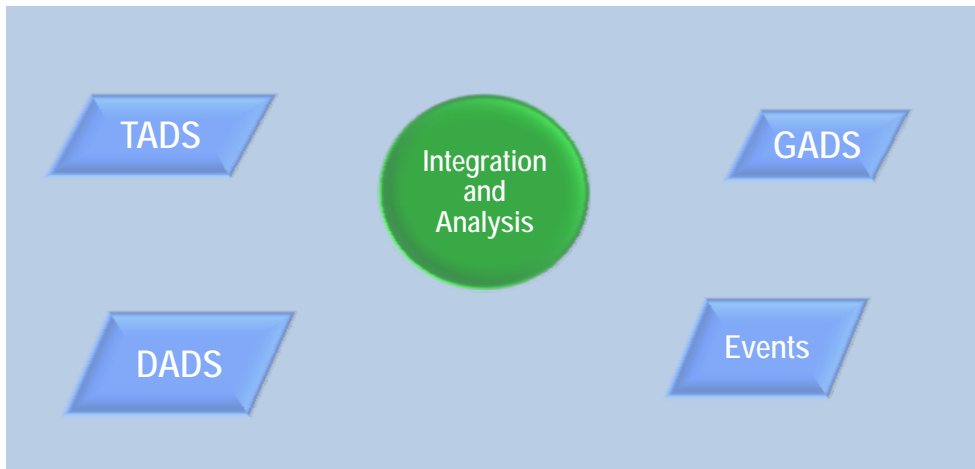


### **The Future Vision**

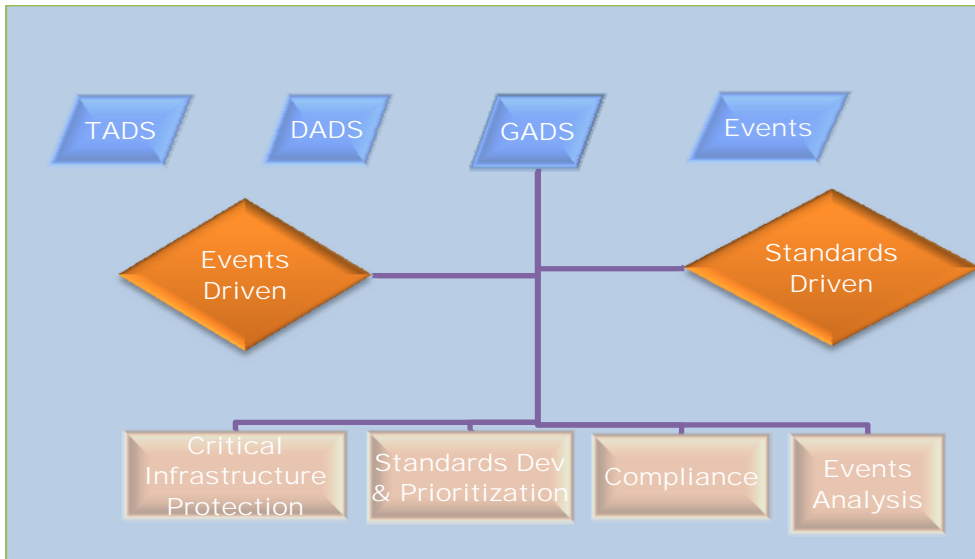
With this information and by working together, the registered entities, Regional Entities and NERC will be able to:

- Communicate the effectiveness of reliability improvement programs
- Provide an integrated view of risk
- Establish quantitative measures for determining achievement of the qualitative reliability goals
- Estimate effectiveness of risk reduction and/or mitigation strategies
- Identify trends and lessons learned
- Support industry analysis of root causes
- Prioritize Standards and Compliance activities

The diagrams below depict the necessary integrations of data and systems and demonstrate the intended direction of the ERO.







Over the next few years, several teams (e.g. EAWG, RMWG, SDT, Risk Framework, etc) will work toward gathering data and publishing reports. The reports will discuss ways to measure and report BPS and equipment performance. They will also:

- Show how unifying existing GADS, TADS, DADS, events and related systems will help create an integrated view of the utility system operations
- Refine and implement risk assessment tools
- Identify areas of highest risk to reliability
- Reveal risk basis for standards and compliance programs
- Provide event-driven risk curves
- Identify reliability indicator trends
- Identify compliance performance measures
- Recommend standard changes and project prioritization

## Section 8 — Appendices and Other Suggested References

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Appendix A — Brief Report Template

Appendix B — Event Categories and Levels of Analysis [August 20, 2010 DRAFT]

Appendix C — Event Analysis Scope Template

Appendix D — Lessons Learned Template

Appendix E — Summary of Roles, Responsibilities and Expectations for Event Reporting and Analysis

Appendix F — Registered Entity Process Checklist

Appendix G — Compliance Analysis Template

Appendix H — Data Retention Hold Notice

### **Other References**

NERC Blackout and Disturbance Analysis Objectives, Analysis Approach, Schedule, and Status  
– Attachment D from Appendix 8 of NERC Rules of Procedure

## Appendix A – Event Reporting Template Instructions

### **Within 24 hours of the event:**

Submit Part A (Notification) if:

- (1) The event meets one of the Categories in **Appendix B** of the ERO Event Analysis Process, and
- (2) Other means of notification of the event have not been submitted as required by OE-417, EOP-004, ES-ISAC, DOE, CIP, etc.

Such Notifications shall be submitted to the appropriate Event Analysis contact at NERC (NERCSA@nerc.net) and the respective Regional Entity.

**Reported Event:** Provide a title that will be used to further identify the event. The title should include the date of the event (e.g. YYYYMMDD, Entity name, substation name)

### **Within five business days of the event:**

Submit Part B (Brief Report) using the previously submitted Part A (with any updates as needed) to the respective Regional Entity. The Regional Entity will collaborate with the registered entity to provide a Brief Report within ten (10) business days of the event to NERC.

The business day count starts on the next business day **after** the event.

**Submittal Date:** Should be updated with every Brief Report update.

**Brief Description (3):** It is expected that a Notification submittal will be shorter than a Brief Report submittal.

**Questions 6 -11:** If the event did involve generation, frequency, transmission facilities, and/or load question (6 – 11), may be left blank.

**Generation Tripped Off-line (6):** Provide a total MW loss and the names of the units that tripped off-line due to the event.

**Restoration Time (11):** Provide the times that affected transmission, generation, and/or were restored.

**Sequence of Events (12):** The sequence of events should provide a timeline of the events that took place leading up to and through the event.

**Narrative (15):** This section should expand on the brief description that was submitted in Part A, providing more detail as needed to more clearly describe the event.

## Reporting Template

### Part A (Notification)

(To be submitted to the Regional Entity and NERC within 24 hours of event – if not provided by other means as described in the instructions)

#### Reported Event:

**Region:**  
**Submittal Date:**

1. **Entity Name:**
2. **Date and Start Time of Disturbance:**
  - a. Date:
  - b. Time: (24-hour format)
  - c. Time Zone EST/EDT
3. **Brief description of event:**

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### Part B (Brief Report)

(To be submitted to the Regional Entity within five business days of event.)

**Status (initial, interim, final):**

4. **Proposed Event Categorization (e.g. 1a, 2b, 3c):**
5. **Name of Contact Person:**
  - a. E-mail Address:
  - b. Telephone Number (xxx-xxx-xxxx):
6. **Generation Tripped Off-line**

MW Total:

List Units Tripped:
7. **Frequency**
  - a. Just prior to disturbance (Hz):
  - b. Immediately following disturbance (Hz MAX):
  - c. Immediately following disturbance (Hz MIN):
8. **List transmission facilities (lines, transformers, buses, etc.) tripped and locked out. (Specify voltage level of each facility listed and extent of equipment damage, if any.)**
9. **Demand Interrupted (MW):** Firm: Interruptible:
10. **Number of Affected Customers:** Firm: Interruptible:

11. **Restoration Time from Time of Event (24-hour format)**
  - a. Transmission:
  - b. Generation:
  - c. Demand:
12. **Sequence of Events:**
13. **Identify contributing causes of the to the extent known:**
14. **Identify any protection system misoperations to the extent known:**
15. **Narrative**
16. **If you supply a one-line diagram, explain that one-line diagram.**
17. **Identify the significance and duration of any monitoring and control events, such as loss of BPS visibility, loss of data links, etc.**

## Appendix B — Event Categories

### Operating Reliability Event Categories

Operating reliability events are those events that are deemed to have significantly impacted the reliable operation of interconnected system. These events are divided into five categories that account for their differing impacts on the system and help determine the level of analysis that is warranted. **The highest category that characterizes an event shall be used.** The lists below are intended to provide examples of the types of events that fall into each category. For events not covered below, the impacted registered entity, in conjunction with the Regional Entity and NERC, will determine the categorization.

#### Category 1: An event resulting in one or more of the following:

- a. Unintended loss of three or more BPS elements caused by common mode failure. For example,
  - i. The loss of a combination of generators, transmission lines, auto transformers and buses.
  - ii. The loss of an entire generation station of three or more generators (aggregate generation of 500 MW to 999 MW); combined cycle units are represented as 1 unit.
- b. Intended and controlled system separation by the proper operation of a Special Protection System Scheme (SPS) / Remedial Action Scheme (RAS) in Alberta from the Western Interconnection, New Brunswick or Florida from the Eastern Interconnection.
- c. Failure or misoperation of SPS/RAS.
- d. System-wide voltage reduction of 3% or more.
- e. Unintended BPS system separation resulting in an island of 100 MW to 999 MW.
- f. Unplanned evacuation from a control center facility with BPS SCADA functionality for 30 minutes or more.

#### Category 2: An event resulting in one or more of the following:

- a. Complete loss of all BPS control center voice communication system(s) for 30 minutes or more.
- b. Complete loss of SCADA, control or monitoring, functionality for 30 minutes or more.
- c. Voltage excursions equal to or greater than 10% lasting more than five minutes
- d. Loss of off-site power (LOOP) to a nuclear generating station.
- e. Unintended system separation resulting in an island of 1,000 MW to 4,999 MW.
- f. Unintended loss of 300MW or more of firm load for more than 15 minutes.
- g. Violation of an Interconnection Reliability Operating Limit (IROL) for more than 30 minutes.

#### Category 3: An event resulting in one or more of the following:

- a. The loss of load or generation of 2,000 MW or more in the Eastern Interconnection or Western Interconnection, or 1,000 MW or more in the ERCOT or Québec Interconnections.

- b. Unintended system separation resulting in an island of 5,000 MW to 10,000 MW.
- c. Unintended system separation resulting in an island of Florida from the Eastern Interconnection.

**Category 4: An event resulting in one or more of the following:**

- a. The loss of load or generation from 5,001 MW to 9,999 MW
- b. Unintended system separation resulting in an island of more than 10,000 MW (with the exception of Florida as described in Category 3c).

**Category 5: An event resulting in one or more of the following:**

- a. The loss of load of 10,000 MW or more.
- b. The loss of generation of 10,000 MW or more.

## Appendix C — Event Analysis Scope Template

Contributing Factor	Explanation of Contributing Factor	Contributing Factor in Causing The Event, Increasing Its Severity, Or Hindering Restoration? (Yes or No)	Explanation
1. Power System Facilities	The existence of sufficient physical facilities to provide a reliable BPS.		
2. Relaying Systems	Detection of bulk power supply parameters that are outside normal operating limits and activation of protective devices to prevent or limit damage to the system. (UFLS/UVLS)		
3. System Monitoring, Operating Control And Communication Facilities	Ability of dispatch and control facilities to monitor and control operation of the bulk power supply system. Adequacy of communication facilities to provide information within and between entities.		
4. Operating Personnel Performance	Ability of system personnel to communicate appropriately and react properly to unanticipated circumstances that require prompt decisive action.		
5. Operational Planning	Study of near-term operating conditions. Application of results to system operation.		
6. System Reserve and Generation Response	Ability of generation or load reduction equipment to maintain or restore system frequency and tie-line flows to acceptable levels following a system disturbance.		
7. Preventive Maintenance	A program of routine inspections and tests to detect and correct potential equipment failures.		
8. Load Relief	The intentional disconnection of customer load in a planned and systematic manner or restoration of the balance between available power supply and demand.		
9. Restoration	Orderly and effective procedures to quickly re-establish customer service and restore the bulk power supply system to a reliable condition.		
10. Special Protection Systems (or Remedial Action Schemes)	An automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other		



	than and/or in addition to the isolation of faulted components to maintain system reliability.		
11. System Planning	Comprehensive planning work using appropriate planning criteria to provide a reliable bulk power supply system.		
12. Reliability Coordinator action	Directives, actions, or procedures of the Reliability Coordinator(s).		
13. Cyber security	Ability of personnel to react properly to unanticipated circumstances that require prompt decisive action.		
14. Other	Any other factor not listed above which was significant in causing the disturbance, making the disturbance more severe or adversely affecting restoration.		

## Appendix D — Lessons Learned

### Information for Completing a Lessons Learned Report

The headings definitions for the Lessons Learned Report are as follows:

**Primary Interest Groups** – The “Primary Interest Groups” heading is to identify those NERC registered entities which could possibly benefit from the information contained in the Lessons Learned report. NERC registered entities are defined per the “NERC Reliability Functional Model Function Definitions and Responsible Entities” document, which can be found on the NERC web site. (Example: Transmission Owner, Generator Owner, Load Serving Entity, etc.)

**Problem Statement** – The “Problem Statement” heading is to provide a short descriptive narrative of the problem that occurred. Usually this can be defined in one sentence, but the purpose of the problem statement is to explain the problem so that the reader is able to easily determine if the problem is of interest without having to go further into the report.

**Details** – The “Details” heading is to provide a concise narrative of the what happened in the event, the end result of the event, the findings of the analysis of the event, corrective actions taken and any other pertinent information that will provide the reader information that could be used in applying the lessons learned to their responsibilities.

**Corrective Actions** – Defines what was learned from the analysis of the event. The lessons learned should be a list of changes the entity incorporated to ensure the event would not happen again. Some examples of items identified are changes in procedures, changes in training programs, equipment replacement, equipment testing changes, etc.

**Lessons Learned** – Knowledge and experience – positive or negative – derived from actual incidents or events as well observations and historical studies of operations, training and exercises.

## Lessons Learned Template

# Lesson Learned — DRAFT TITLE

### Primary Interest Groups

### Problem Statement

### Details

### Corrective Actions

### Lesson Learned

For more information please contact:

Earl Shockley

Director of Event Analysis and Investigation

[earl.shockley@nerc.net](mailto:earl.shockley@nerc.net)

*This document is designed to convey lessons learned from NERC's various activities. It is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing reliability standards. Compliance will continue to be determined based on language in the NERC Reliability Standards as they may be amended from time to time. Implementation of this lesson learned is not a substitute for compliance with requirements in NERC's Reliability Standards.*

## Appendix E — Summary of Roles, Responsibilities and Expectations for Event Reporting and Analysis

Category 1 Events			
Entity	Brief Report	Event Analysis Report (EAR)	Lessons Learned
<b>Registered Entity</b>	<p>Ensure notification was provided to the Regional Entity and NERC.</p> <p>Provide initial report to Regional Entity and NERC in accordance with requirements specified in applicable NERC standards.</p> <p>Ensure content of report is consistent with Event Reporting Template included in <b>Appendix A</b>.</p> <p>Provide Brief Report in five business days or less.</p>		<p>Provide Draft of suggested lessons learned to Regional Entity within 15 business days of event occurrence.</p>
<b>Regional Entity</b>	<p>Request additional event information from registered entity as needed.</p> <p>Send Brief Report to NERC within 10 business days of the event.</p> <p>Notify registered entity that event analysis is closed unless NERC has additional questions.</p>		<p>Review draft lessons learned from registered entity. Request additional information as deemed necessary.</p> <p>Work with registered entity and NERC to prepare final lessons learned for review by EAWG.</p>
<b>NERC</b>	<p>Coordinate with Regional Entity to determine whether additional event report information from registered entity should be provided.</p> <p>Raise additional questions before Regional Entity closes event analysis</p>		<p>Work with registered entity and Regional Entity to prepare final lessons learned for review by EAWG.</p> <p>Disseminate final lessons learned to industry.</p>

## Appendix E — Summary of Roles, Responsibilities, and Expectations for Event Reporting and Analysis

Category 2 and 3 Events			
Entity	Brief Report	Event Analysis Report (EAR)	Lessons Learned
<b>Registered Entity</b>	<p>Ensure notification was provided to the Regional Entity.</p> <p>Provide initial event report to Regional Entity and NERC in accordance with requirements specified in applicable NERC standards.</p> <p>Ensure content of report is consistent with Event Report Template included in Appendix A.</p> <p>Provide Brief Report in five business days or less.</p>	<p>Hold data relevant to the event for 120 days unless notified by the Regional Entity.</p> <p>Provide EAR to Regional Entity within 30 business days for Category 2 event or 60 business days for Category 3 events. Registered Entity and Regional Entity should collaborate on the expectations for the report and any extensions to the due dates.</p>	<p>Provide draft of suggested lessons learned to Regional Entity within 30 business days of event occurrence.</p>
<b>Regional Entity (RE)</b>	<p>Request additional event information from registered entity as determined by Regional Entity or in collaboration with NERC.</p> <p>Send Data Hold Retention Notice to entity.</p> <p>Send Brief Report to NERC within 10 business days of the event.</p>	<p>Request EAR if not initiated by registered entity. Specify deadline.</p> <p>Follow progress of event analysis and report preparation with Entity.</p> <p>Review EAR for sufficiency and request additional analysis or information as deemed necessary. Specify deadline and inform NERC.</p> <p>Notify registered entity that event analysis is closed unless NERC has additional questions.</p>	<p>Review draft lessons learned from registered entity. Request additional information as deemed necessary.</p> <p>Work with registered entity and NERC to prepare final lesson learned for review by EAWG.</p>
<b>NERC</b>	<p>Coordinate with Regional Entity to determine if additional event information is needed.</p>	<p>Review final version of EAR, and provide comments to Regional Entity Before Regional Entity closes event analysis.</p>	<p>Work with registered entity and Regional Entity to prepare final lessons learned for review by EAWG.</p> <p>Disseminate final lesson learned to industry.</p>

## Appendix E — Summary of Roles, Responsibilities and Expectations for Event Reporting and Analysis

<b>Category 4 and 5 Events</b>			
<b>Entity</b>	<b>Brief Report</b>	<b>Event Analysis Report (EAR)</b>	<b>Lessons Learned</b>
<b>Registered Entity</b>	<p>Ensure notification was provided to the Regional Entity.</p> <p>Provide initial event report to Regional Entity and NERC in accordance with requirements specified in applicable NERC standards.</p> <p>Ensure content of report is consistent with Event Report Template included in <b>Appendix A</b>.</p> <p>Provide Brief Report in five business days or less.</p>	<p>Hold data relevant to the event for 120 days unless notified by the Regional Entity.</p> <p>Participate in event analysis as directed by Regional Entity and NERC.</p>	<p>Provide draft of suggested lessons learned to Regional Entity within 60 business days of event.</p>
<b>Regional Entity (RE)</b>	<p>Request additional event information from registered entity as determined by Regional Entity or requested by NERC.</p> <p>Send Data Hold Retention Notice to entity.</p> <p>Send Brief Report to NERC within 10 business days of the event.</p>	<p>Conference call of affected registered entities, Regional Entities involved, and NERC within five business days of occurrence of event to discuss approach for conduct of event analysis and agreement on composition and lead for event analysis team.</p> <p>Collaborate with NERC on request for information from affected registered entities.</p> <p>Coordinate event analysis for multi-entity events within Regional Entity. (Category 4)</p> <p>Participate in multi-regional event analysis led by NERC. (Category 5)</p> <p>Follow progress of event analysis and report preparation.</p> <p>Notify registered entity that event analysis is closed with agreement of NERC for Category 4 events.</p>	<p>Review draft lessons learned from registered entity. Request additional information as deemed necessary.</p> <p>Work with registered entity and NERC to prepare final lessons learned for review by EAWG.</p>
<b>Category 4 and 5 Events</b>			
<b>NERC</b>	<p>Request Regional Entity to provide additional event report information from registered entity, as needed.</p>	<p>Conference call of affected registered entities, Regional Entities involved, and NERC within five business days of occurrence of event to discuss approach for conduct of event analysis and agreement on composition and lead for event</p>	<p>Work with registered entities and Regional Entity(s) to prepare final lessons learned for review by EAWG.</p> <p style="text-align: right;">31</p> <p>Disseminate final lessons learned to</p>

		<p>analysis team.</p> <p>Collaborate with Regional Entity(s) involved on request for information from affected registered entities.</p> <p>Participate in multi-entity events within Regional Entity, led by Regional Entity. (Category 4)</p> <p>Lead multi-regional event analyses when determined by NERC president. (Category 4 or 5)</p> <p>Notify registered entity that event analysis is closed for Category 5 events, with agreement of the applicable Regional Entities</p>	<p>industry.</p>
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## Appendix F — Registered Entity Process Checklist

1. Event occurs.
2. Ensure notification was provided to the Regional Entity and NERC within 24 hours.
3. Confer with Regional Entity to confirm event category AND analysis/reporting requirements.
4. IF **Category 1** THEN:
  - a. **Brief Report:** Report in accordance with NERC or Regional Reliability Standards requirements or as otherwise requested by Regional Entity. Brief Report in five business days or less.
  - b. **Lessons Learned:** Draft of suggested lessons learned (if any) to Regional Entity within 15 business days of event occurrence.
  - c. **Compliance Review:** Initiate concurrently with Brief Report. Submittal of Compliance Review is not required for Category 1 events.
  - d. **Corrective Action Plan (or Recommendation):** If there are recommendations or corrective actions identified that will prevent recurrence, they should be included in the final Brief Report
5. IF Category 2 THEN:
  - a. **Data Hold:** Capture data relevant to the event and hold for 120 days unless otherwise notified.
  - b. **Brief Report:** Report in accordance with NERC or Regional Reliability Standards requirements or as otherwise requested by Regional Entity. Brief Report in five business days or less.
  - c. **Event Analysis Report:** Initiate and submit report to Regional Entity within 30 business days (collaborate on content with Regional Entity).
  - d. **Lessons Learned: Draft** of suggested lessons learned to Regional Entity within 30 **business days** of event occurrence.
  - e. **Compliance Review:** Initiate concurrently with EAR; complete within 60 days after Brief Report.
  - f. **Corrective Action Plan (or Recommendation):** If there are recommendations or corrective actions identified that will prevent recurrence, they should be included in the final Brief Report
6. IF **Category 3** THEN:
  - a. **Data Hold: Capture data** relevant to the event and hold for 120 days unless otherwise notified.
  - b. **Brief Report:** Report in accordance with NERC or Regional Reliability Standards requirements or as otherwise requested by Regional Entity. Brief Report in five business days or less.
  - c. **Event Analysis Report:** Finalize report to Regional Entity within 60 business days of event occurrence (or by time agreed to with Regional Entity).
  - d. **Lessons Learned:** Draft of suggested lessons learned to Regional Entity within 30 business days of event occurrence.)
  - e. **Compliance Review:** Initiate concurrently with EAR; provide list of standards/requirement being reviewed within 20 days; complete within 90 days after Brief Report.
  - f. **Corrective Action Plan (or Recommendation):** If there are recommendations or corrective actions identified that will prevent recurrence, they should be included in the final Brief Report.



**7. IF Category 4 THEN:**

- a. **Data Hold: Capture data** relevant to the event and hold for 120 days unless otherwise notified.
- b. **Brief Report:** Report in accordance with NERC or Regional Reliability Standards requirements or as otherwise requested by Regional Entity. Brief Report in five business days or less.
- c. **Event Analysis Report:** Finalize report to Regional Entity within 120 business days of event occurrence (or by time agreed to with Regional Entity).
- d. **Lessons Learned:** Draft of suggested lessons learned to Regional Entity within 60 business days of event occurrence.
- e. **Compliance Review:** Initiate concurrently with EAR; provide list of standards/requirement being reviewed within 20 days; complete within 150 days after Brief Report.
- f. **Corrective Action Plan (or Recommendation):** If there are recommendations or corrective actions identified that will prevent recurrence, they should be included in the final Brief Report

**8. IF Category 5 THEN:**

- a. **Data Hold:** Capture data relevant to the event and hold for 120 days unless otherwise notified.
- b. **Brief Report:** Report in accordance with NERC or Regional Reliability Standards requirements or as otherwise requested by Regional Entity. Brief Report in five business days or less.
- c. **Event Analysis Report:** Finalize report to Regional Entity within 120 business days of event occurrence (or by time agreed to with Regional Entity).
- d. **Lessons Learned:** Draft of suggested lessons learned to Regional Entity within 60 business days of event occurrence.
- e. **Compliance Review:** Initiate concurrently with EAR; provide list of standards/requirement being reviewed within 20 days; complete within 150 business days after Brief Report.
- f. **Corrective Action Plan (or Recommendation):** If there are recommendations or corrective actions identified that will prevent recurrence, they should be included in the final Brief Report

## Appendix G — Compliance Assessment Template

The registered entity’s compliance function is expected to perform an initial compliance assessment, concurrent with the registered entity’s event analysis process.

A systematic, methodical compliance assessment process might include the following steps:

1. Refer to the causes and contributing factors of the event as determined by the registered entity’s event analysis process.
2. Identify any applicable Reliability Standards requirement that may have been implicated by the causes and contributing factors of the event.
3. Develop conclusions after reviewing the facts and circumstances of the event that are relevant to step 2 above as they apply to the applicable Reliability Standards requirements.
4. Self-report any findings of non-compliance to the Regional Entity per the CMEP procedures.

### Sample Template for Compliance Assessment Summary

<b>Event causes or contributing factors</b>	<b>Applicable NERC Reliability Standards</b>	<b>Details of Compliance Assessment Effort</b>	<b>Findings</b>
Cause	AAA-000-0 Requirement 1	Identify the process used to assess compliance with this requirement.  Identify any evidence that demonstrates compliance.  Identify any evidence that suggests non-compliance.	Findings of possible violations should be identified.  If there are no findings of non-compliance, that should be noted.
	AAA-000-0 Requirement 2		
Contributing factor	BBB-000-0 Requirement 1		

### Category 1a Example

Event causes or contributing factors	Applicable NERC Reliability Standards	Details of Compliance Assessment Effort	Findings*
Equipment failure of a high side transformer– cleared along with two transmission lines.	<b>TOP-002-2a R6.</b> Each BA and TOP shall plan to meet unscheduled changes in system configuration and generation dispatch (at a minimum N-1 Contingency planning) in accordance with NERC, Regional Reliability Organization, sub-regional and local reliability requirements.	Established transfer limits were followed such that the event did not result in instability. The limit for operating across this internal interface is established in the RC.  “ <u>XYZ Interface All Lines In Stability Guide</u> ” (document provided)	No findings of non-compliance.*
Equipment failure of a high side transformer– cleared along with two transmission lines.	<b>TOP-002-2a R10.</b> Each Balancing Authority and Transmission Operator shall plan to meet all System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs).	No SOLs were violated. There are no IROLs associated with the loss of equipment in this event. See the specific guide referenced in the response to <b>TOP-002-2a R6</b> .	No findings of non-compliance.*
Equipment failure of a high side transformer– cleared along with two transmission lines.	<b>TOP-004-2 R1.</b> Each TOP shall operate within the IROLs and SOLs. <b>R2.</b> Each TOP shall operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency.	The system was operated to remain within transfer limits across the “XYZ” internal interface established as a result of stability studies as delineated in the Transmission Operating Guide developed by RC. See the specific guide referenced in the response to <b>TOP-002-2a R6</b> .	No findings of non-compliance*
Equipment failure of a high side transformer– cleared along with two transmission lines.	<b>PRC-001 R1.</b> Each TOP, BA and GOP shall be familiar with the purpose and limitations of protection system schemes applied in its area.	Both the RC and the TOPs are trained on the Transmission Operating Guides as well as relaying and SPSs on the BPS. Protection operated correctly and as planned.	No findings of non-compliance*
Equipment failure of a high side transformer– cleared along with two transmission lines.	<b>PRC-004 R1.</b> The TOP and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity’s procedures.	System Protection engineers evaluated the relay operations and determined that all relaying operated correctly and as planned.	No findings of non-compliance*
Equipment failure of a high side transformer– cleared	<b>TOP-008 R1.</b> The TOP experiencing or contributing to an IROL or SOL	R1 Operators used their EMS-based tools to ensure that there were no	No findings of non-compliance*

<p>along with two transmission lines.</p>	<p>violation shall take immediate steps to relieve the condition, which may include shedding firm load.</p> <p><b>R2.</b> Each Transmission Operator shall operate to prevent the likelihood that a disturbance, action, or inaction will result in an IROL or SOL violation in its area or another area of the Interconnection. In instances where there is a difference in derived operating limits, the TOP shall always operate the BPS to the most limiting parameter.</p> <p><b>R3.</b> The TOP shall disconnect the affected facility if the overload on a transmission facility or abnormal voltage or reactive condition persists and equipment is endangered. In doing so, the TOP shall notify its RC and all neighboring TOPs impacted by the disconnection prior to switching, if time permits, otherwise, immediately thereafter.</p> <p><b>R4.</b> The TOP shall have sufficient information and analysis tools to determine the cause(s) of SOL violations. This analysis shall be conducted in all operating timeframes. The TOP shall use the results of these analyses to immediately mitigate the SOL violation.</p>	<p>SOL/IROL violations.</p> <p>R2 by following the TOP Guides developed by RC, violations do not occur.</p> <p>R3 no conditions occurred that required disconnection.</p> <p>R4 Operators used their EMS-based tools to ensure that there were no SOL/IROL violations.</p>	
<p>Equipment failure of a high side transformer– cleared along with two transmission lines.</p>	<p><b>TOP-006</b></p> <p><b>R2.</b> Each RC, TOP and BA shall monitor applicable transmission line status, real and reactive power flows, voltage, load-tap-changer settings, and status of rotating and static reactive resources.</p> <p><b>R5</b> Each RC, TOP and BA shall use monitoring equipment to bring to the attention of operating personnel important deviations in operating conditions and to indicate, if appropriate, the need for corrective action.</p>	<p>The EMSs at both the RC and the TOP provide operators with the information needed to evaluate system conditions and notify operators when conditions are off normal. EMS system visibility and communications were not lost during this event.</p>	<p>No findings of non-compliance*</p>

			<p>*Findings as the outcome of a compliance self-assessment will result in either a statement of “No Findings” or that of “Possible Violation (PV).”</p> <p>Should the latter be the result, the entity will be given the opportunity to self-report the PV to the Regional Compliance Enforcement department, in accordance with the existing procedures set forth in the CMEP. In doing so, the entity self-reporting should inform the Regional Compliance Enforcement department that this has been done consistent with the event analysis process and the completion of a compliance self-assessment (<b>Appendix G</b>) to obtain the credit prescribed.</p>
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## Appendix H – Data Retention Hold Notice

**CONFIDENTIAL — NON-PUBLIC**

### **DATA RETENTION HOLD NOTICE**

**Subject:** [ ]

**Notice Date:** [DATE]

**Date of Event:** [DATE]

The [Name of Issuer] is reviewing the circumstances surrounding the [Description of Event] (Event).

Therefore, this letter serves as *official notice* to [Registered Entity Name] to preserve and retain and not discard or destroy any and all data or documentation pertaining to the Event.

- Documentation includes, but is not limited to: operator logs, recorded voice communications, e-mail and written correspondence, work orders, inspection records, patrol records, and any other documents, fault recorder records, data or other information that may be directly or indirectly related to the Event, including “Electronic Data.” In addition, documentation includes, but is not limited to e-mails and other forms of communication, including Electronic Data, from entity personnel, including management, that may be directly or indirectly related or relevant to the Event.
- Documentation includes, but is not limited to: Energy Management System (EMS) data with regards to system load, frequency, online and offline generation energy/capacity, reserve capacity, forecasted load, capacity study results, interchange schedules, Market Analyst Interface, SCADA, and any other documents, data or other information that may be directly or indirectly related to the Event.
- “Electronic Data” shall include, but not be limited to: all planning power system models, operational planning system models, text files (including word processing documents), spreadsheets, e-mail files and information concerning e-mail (including logs of e-mail history and usage, header information and “deleted” files), internet history files and preferences, graphical image format (GIF) files, databases, calendar and scheduling information, computer system activity logs, and all file fragments and backup files containing Electronic Data.

**[Registered Entity Name]** is required, upon request, to produce any requested data pursuant to Title 18 of the Code of Federal Regulations (CFR)<sup>2</sup> Part 39.

This Notice will be in effect for 120 calendar days from the date of issuance, unless extended by **[Issuer]**.

Please confirm by e-mail, within 24 hours of receipt, that you have received this message.

If you have any questions regarding this Notice and related requirements please contact me at any time using my contact information below.

Respectfully submitted,

**[Insert Signature]**

**[Insert Name]**

**[Insert Title and Contact Information]**

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<sup>2</sup> 18 CFR Part 39, Section 39.2 requires: (d) Each user, owner or operator of the Bulk-Power System within the United States (other than Alaska and Hawaii) shall provide the Commission, the Electric Reliability Organization and the applicable Regional Entity such information as is necessary to implement section 215 of the Federal Power Act as determined by the Commission and set out in the Rules of the Electric Reliability Organization and each applicable Regional Entity. The Electric Reliability Organization and each Regional Entity shall provide the Commission such information as is necessary to implement section 215 of the Federal Power Act.

## ERO Enterprise Performance Metrics

### Action Required

None

### Background

At the February 16, 2011 MRC meeting, Dave Nevius and Mark Lauby of NERC staff provided an overview of several NERC Metrics Initiatives that were underway and their current progress. At this meeting the MRC will hear how the several metrics initiatives are being integrated into a single, coordinated set of ERO Enterprise Performance Metrics that measure both system reliability performance and NERC and Regional Entity performance in support of ERO Strategic Goals and Objectives.

### Overview of Metric Initiatives

There are two components of performance metrics under development: i) bulk power system reliability performance metrics and ii) NERC and Regional Entity organizational performance metrics. The first component includes several bulk power system-level reliability indicators, which comprise multiple dimensions of system-level reliability performance indicators to enable industry to identify and understand reliability issues and trends in the areas of system design, planning, operating, and maintenance. The second component refers primarily to how NERC and Regional Entities (REs) carry out their respective roles under the Regional Delegation Agreements (RDAs), Rules of Procedure, and applicable regulations. These metrics will enable NERC and the REs to benchmark organizational performance and to identify areas for improvement and actions needed to address them.

Fundamentally, NERC and the REs should be measured by bulk power system reliability performance – it's why the ERO exists. Because the two components described above have important correlations, both will be measured as together they will provide the whole context for assessing the success of the ERO Enterprise. The more efficiently and effectively NERC and the REs carry out their respective functions and responsibilities, the more system reliability performance should improve.

### System Reliability Performance Metrics

Mark Lauby, vice president and director of reliability assessment and performance improvement, will review several reliability risk-based metrics being collected and tracked.

Under the direction of the Operating Committee (OC) and Planning Committee (PC), the Reliability Metrics Working Group (RMWG) has developed a portfolio of 18 Adequate Level of Reliability (ALR) metrics<sup>1</sup> and three risk-based indices to quantify bulk power system reliability, including event-driven risk index (EI),<sup>2</sup> condition-driven reliability index (CI),<sup>3</sup> standards/statute-driven risk index (SI),<sup>4</sup> as illustrated in Figure 1. This model attempts to capture the “universe of risk” to the bulk power system reliability.

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<sup>1</sup> [http://www.nerc.com/docs/pc/rmwg/RMWG\\_AnnualReport6.1.pdf](http://www.nerc.com/docs/pc/rmwg/RMWG_AnnualReport6.1.pdf)

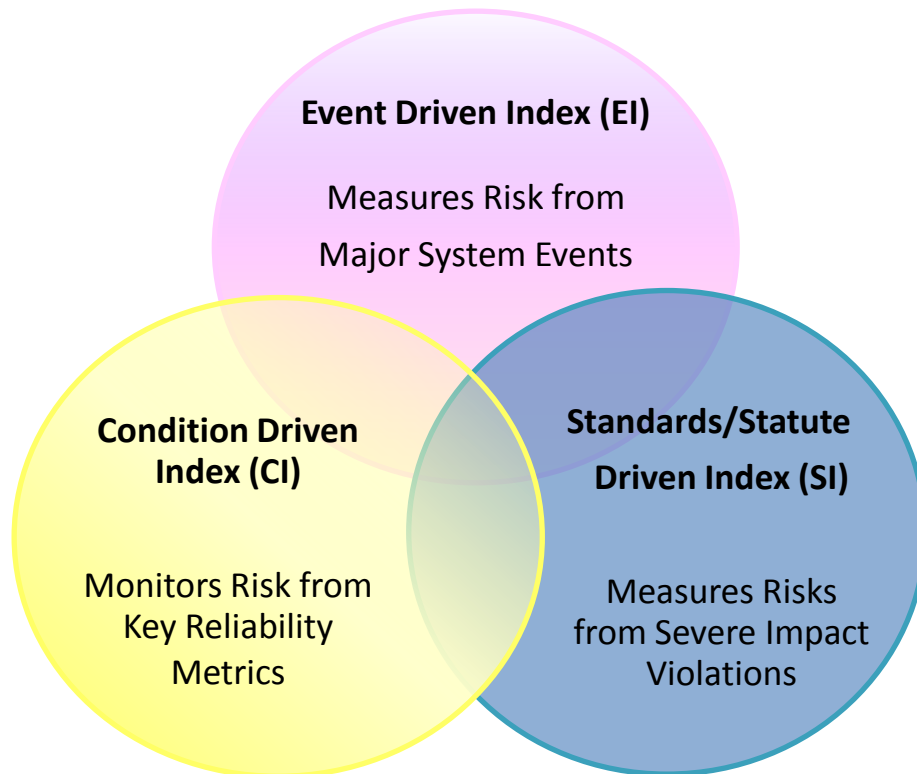
<sup>2</sup> [http://www.nerc.com/docs/pc/rmwg/Integrated\\_Bulk\\_Power\\_System\\_Risk\\_Assessment\\_Concepts\\_Final.pdf](http://www.nerc.com/docs/pc/rmwg/Integrated_Bulk_Power_System_Risk_Assessment_Concepts_Final.pdf)

<sup>3</sup> [http://www.nerc.com/docs/pc/rmwg/RMWG\\_Metric\\_Report-09-08-09.pdf](http://www.nerc.com/docs/pc/rmwg/RMWG_Metric_Report-09-08-09.pdf)

<sup>4</sup> [http://www.nerc.com/docs/pc/UPDATED\\_PC\\_%20AgendaPKG\\_March\\_2011v3.pdf](http://www.nerc.com/docs/pc/UPDATED_PC_%20AgendaPKG_March_2011v3.pdf) (agenda Item 6.b., Attachment 3)



**Figure 1 – Risk Model for Bulk Power System**



At its last meeting, the OC and PC approved the Event Severity Risk Index (SRI)<sup>5</sup> calculation and supported development of an Integrated Reliability Index (IRI), which can be constructed based on the risk model illustrated in Figure 1. The development of an integrated reliability index aims to inform, increase transparency, and quantify the effectiveness of risk reduction and/or mitigation actions. The goal is to provide the industry meaningful trends of the bulk system performance and guidance on how they can improve reliability and support risk-informed decision making.

The IRI includes the following three components:

- **Major Event Risk Index (EI)** - Risk value associated with significant events
- **Condition Driven Index (CI)** - Key reliability metrics covering major factors to reliability
- **Standards/Statute Driven Index (SI)** – Violations having severe impact to reliability

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<sup>5</sup> [http://www.nerc.com/docs/pc/UPDATED\\_PC\\_%20AgendaPKG\\_March\\_2011v3.pdf](http://www.nerc.com/docs/pc/UPDATED_PC_%20AgendaPKG_March_2011v3.pdf) (agenda Item 6.b., Attachment 1)

The value of the IRI can be calculated based on risk impact of the above three components and their relative weightings, as shown below:

$$IRI = w_E*(EI) + w_C*(CI) + w_S*(SI) \quad (1)$$

Where:

IRI = integrated reliability index for a specific period,

$w_E$  = weighting of event component,

EI = normalized event severity risk level in percent,

$w_C$  = weighting of condition component,

CI = normalized condition indicator level in percent,

$w_S$  = weighting of standard compliance component,

SI = normalized standard compliance level in percent

The value of IRI will range from 0 to 100, and can be aggregated at NERC, Interconnection and Regional levels. The three weights can be adjusted as we learn more and gain experience after one to two years of trending.

Criteria for IRI components include that risk factors should not be double-counted across each component, they should be measurable for specific time periods of interest, such as quarterly or annually, and they should have independence from each other. Conceptually, the components might be considered as “success rates” for events experienced (as measured by EI), compliance history (as measured by SI) and condition performance (as measured by CI).

- **Major Event Risk Index (EI)**

EI component is obtained from RMWG’s Severity Risk Index (SRI) values.<sup>6</sup> The SRI is the value of the risk severity based on the impact of significant events. It includes generator outages, transmission outages, as well as load loss and its durations. The EI can be computed as follows:

$$EI = (\text{Duration in Days} - \sum SRI) / (\text{Duration in Days}) \quad (2)$$

The value of EI will range from 0 and 100. The SRI is a daily Severity Risk Index and the duration is a specific time period of interest, such as quarterly or annually. Figure 2 provides the 2008-2010<sup>7</sup> NERC SRI curves, including historic benchmark events using the same SRI formula. The daily 2008-2010 generation and AC transmission line outages were obtained from GADS (Generating Availability Data System) and TADS (Transmission

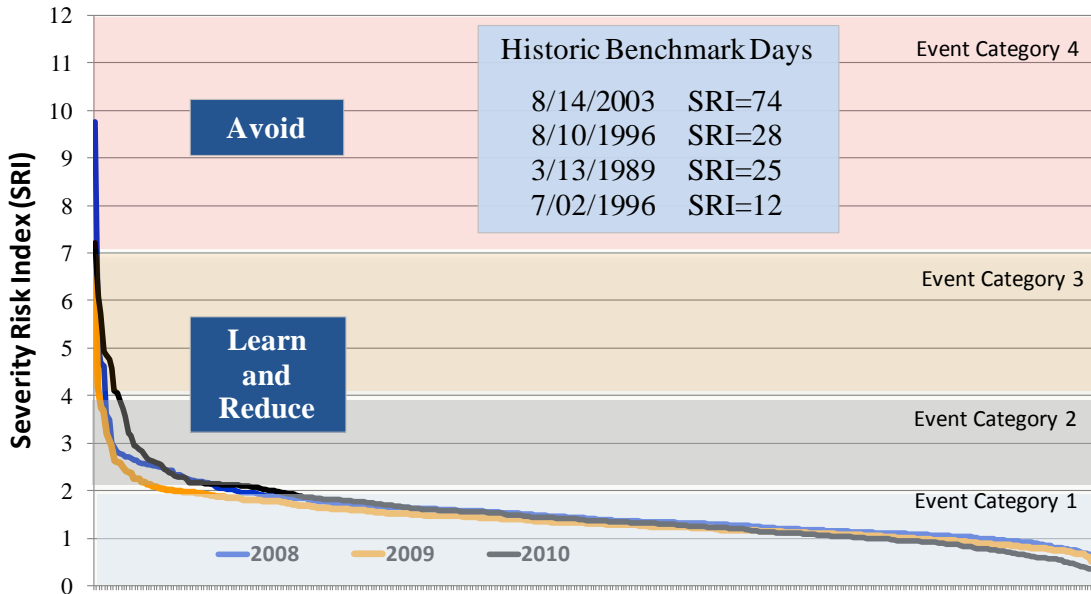
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<sup>6</sup> [http://www.nerc.com/docs/pc/rmwg/Integrated\\_Bulk\\_Power\\_System\\_Risk\\_Assessment\\_Concepts\\_Final.pdf](http://www.nerc.com/docs/pc/rmwg/Integrated_Bulk_Power_System_Risk_Assessment_Concepts_Final.pdf)

<sup>7</sup> The 2010 event risk curve shown here is preliminary. The curve will be updated when a complete 2010 GADS data set is available.

Availability Data System). The load loss and duration data are gathered from EOP-004 and OE-417 reports. The event category<sup>8</sup> and its associated severity risk range are summarized in Table 1.

**Figure 2 – NERC 2008-2010 Severity Risk Index versus Benchmark Days**



**Table 1 – Event Category and Severity Risk Index Range**

Event Category	SRI Range
1	0 - 2
2	2 - 4
3	4 - 7
4	7 - 12
5	12 +

- **Condition Driven Index (CI)**

The RMWG recommends the following six reliability indicators be included in CI component.

- ALR1-5 – System Voltage Performance (metric focused by OC)
- ALR1-12 – Interconnection Frequency Response (metric focused by OC)
- ALR2-5 – Disturbance Control Standard (DCS) events greater than Most Severe Single Contingency (MSSC)

<sup>8</sup> [http://www.nerc.com/docs/eawg/Event\\_Analysis\\_Process\\_Field\\_test\\_DRAFT\\_102510-Clean.pdf](http://www.nerc.com/docs/eawg/Event_Analysis_Process_Field_test_DRAFT_102510-Clean.pdf)

- ALR3-5 – IROL/SOL Exceedance (less than 30 minutes, metric focused by OC)
- ALR4-1 – Protection System Misoperation
- ALR6-2 – Energy Emergency Alert 3

Three of reliability indicators are recommended by OC to be closely monitored and tracked; and the other three indicators are also direct measures and early predictors of the risk to reliability.

- **Standards/Statute Driven Index (SI)**

The RMWG recommends using the Reliability Impact Statement (RIS) and Violation Risk Factor (VRF) as selection criteria to identify which subset of standard requirements should be included in SI. RIS is the initial violation assessment of risk to the bulk power system, as determined by the Regional Entity. The three RIS marks are minimal impact, moderate impact and severe impact. The factors included in the RIS are

- Time Horizon
- Relative size of the entity
- Relationship to other entities
- Possible sharing of responsibilities
- Voltage levels involved
- Size of generator or equipment involved
- Ability to project adverse impacts beyond the entity’s own system

Based on the above criteria, the following 26 standard requirements are identified from the NERC 3-year compliance database where their violations all have severe RIS and high VRF.

**Table 2 – Standard Requirements\* included in Standard Compliance Index**

Standard	Req.	Standard	Req.	Standard	Req.	Standard	Req.	Standard	Req.
EOP-001-0	R1.	FAC-009-1	R1.	PER-002-0	R3.	PRC-005-1	R2.	TOP-004-2	R1.
EOP-003-1	R7.	IRO-005-2	R17.	PER-002-0	R4.	TOP-001-1	R3.	TOP-004-2	R2.
EOP-005-1	R6.	PER-001-0	R1.	PRC-004-1	R1.	TOP-001-1	R6.	TOP-006-1	R6.
EOP-008-0	R1.	PER-002-0	R1.	PRC-004-1	R2.	TOP-001-1	R7.	TOP-008-1	R2.
FAC-003-1	R1.	PER-002-0	R2.	PRC-005-1	R1.	TOP-002-2	R17.	VAR-001-1	R1.
FAC-003-1	R2.								

\*Requirements are identified from the NERC compliance database where their violations have severe RIS.

By applying the similar aggregation as EI, the SI can be calculated as

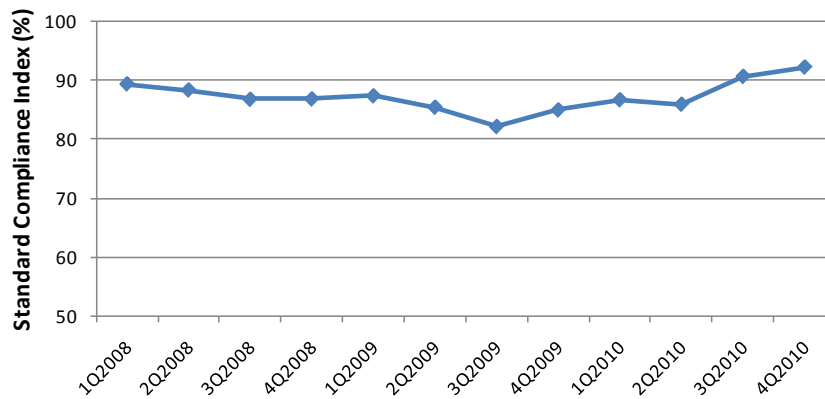
$$SI = 100 - \sum (w_v * NV / NR) \quad (3)$$

Where:

- SI = integrated standard compliance index for a specific period,
- $w_v$  = weighting of a particular requirement violation,
- NV = number of violations for the selected requirement,
- NR = number of registered entities who are required to comply with the selected requirement

Figure 3 provides the 2008-2010 SI trends, indicating the risk due to known severe impact violations has decreased, and a higher reliability level has been achieved through standards compliance since third quarter 2009.

**Figure 3 – NERC 2008-2010 Standards Compliance Index Trend by Quarter**



### Reliability Dashboard Demonstration

NERC has also developed a new Reliability Dashboard for displaying its reliability risk-based metrics. Jessica Bian, manager of performance analysis, will demonstrate the latest version of the Reliability Dashboard<sup>9</sup> and address comments and questions.

### Regional Delegation Agreement Metrics

NERC and the Regional Entities have recommitted to developing Regional Delegation Agreement metrics to measure how NERC and REs carry out their respective roles under the RDAs, Rules of Procedure and applicable regulations. The latest draft of proposed RDA Metrics (**Attachment 1**), while still a work in progress, identifies a number of metrics and associated measures of NERC and RE performance that can be tracked, trends identified, and actions taken to achieve greater improvements.

<sup>9</sup> See <http://www.nerc.com/page.php?cid=4|331>

The proposed RDA metrics cover the following functions and responsibilities that appear in the RDAs:

- Compliance Registration
- Compliance Audits
- Enforcement
- Mitigation of Compliance Violations
- Event Analysis
- Reliability Standards/Regional Standards
- Reliability Assessment
- 

Each metric includes at least one measure as well as a relationship link to one or more of the ERO Enterprise Strategic Goals and Objectives presented at the February 2011 meeting.

As the RE and NERC staff are continuing to work to refine and improve these metrics and measures, they welcome comments and suggestions from the MRC.

**Proposed Regional Delegation Agreement (RDA) Metrics  
WORKING DRAFT – April 26, 2011**

**Reference to Metrics in Pro Forma RDA**

Section 8(a) of the pro forma RDA states with regard to performance metrics:

- (i) NERC shall develop, in collaboration with [Regional Entity] and other Regional Entities, performance goals, measures and other parameters (including, without limiting the scope of such goals, measures and parameters, financial performance goals, measures and parameters), and performance reports, which shall be used to measure NERC's and [Regional Entity's] performance of their respective functions and related activities. The performance goals, measures and parameters and the form of performance reports shall be approved by the NERC President and shall be made public. [Regional Entity] shall provide data, information and reports to NERC, in accordance with established schedules, to enable NERC to calculate [Regional Entity's] performance to the agreed-upon goals, measures and parameters.
- (ii) NERC shall use the performance goals, measures and parameters and performance reports to evaluate [Regional Entity's] performance of its delegated functions and related activities and to provide advice and direction to [Regional Entity] on performance improvements. The performance goals, measures and other parameters and the values of such goals, measures and parameters, shall be reviewed by NERC, [Regional Entity] and the other Regional Entities, revised if appropriate, and made public, on the same timeline as the annual business planning and budgeting process described in Section 9 of this Agreement.
- (iii) At the request of the President of NERC, [Regional Entity] shall be required to develop, submit for NERC approval, and implement action plans to address areas of its performance that are reasonably determined by NERC, based on analysis of [Regional Entity's] performance against the performance goals, measures and parameters, or performance of specific activities, to be unsatisfactory, *provided*, that prior to requiring [Regional Entity] to adopt and implement an action plan or other remedial action, NERC shall issue a notice to [Regional Entity] of the need and basis for an action plan or other remedial action and provide an opportunity for [Regional Entity] to submit a written response contesting NERC's evaluation of [Regional Entity's] performance and the need for an action plan. [Regional Entity] may request that the President of NERC reconsider the request, and thereafter may request that the NERC Board review and reconsider the request. NERC and [Regional Entity] shall work collaboratively as needed in the development and implementation of [Regional Entity's] action plan. A final action plan submitted by [Regional Entity] to NERC shall be made public unless the President of NERC makes a written determination that the action plan or specific portions of the plan should be maintained as non-public.

## **Working Assumptions for RDA Metrics**

1. The purpose of establishing RDA metrics is to measure and track key elements of NERC and Regional Entity (RE) performance of their respective and related RDA functions and responsibilities to: (a) establish performance trends, (b) help identify where performance improvements may be needed and, ultimately, (c) jointly establish agreed upon performance benchmarks.
2. The purpose of the metrics and the associated measures is not to establish performance targets, to compare one RE's performance with others, or to rank them.
3. The metrics will be associated with the key NERC and RE RDA functions and responsibilities at a high level with emphasis on those that will help ensure a "common look and feel" across all REs from the perspective of registered entities.
4. Each metric should relate to one or more of the long-term Strategic Goals and Objectives of the ERO Enterprise, with emphasis on those that promote risk-based activities. As these strategic goals and objectives change, the metrics will be reviewed and revised as needed.
5. The metrics will be simple, understandable, and few, easy to measure, and avoid administrative details.
6. After sufficient experience is gained with the RDA metrics, NERC and the REs, working together, will develop and agree upon performance benchmarks (targets) for each RDA function or responsibility for the coming year.
7. Metrics will be measured either by trends in numerical measures (average time to complete required tasks) or pass/fail (% satisfactory ratings.)
8. RDA metrics are separate from but related to system reliability performance metrics, such as condition driven, event driven, and standard/statute driven metrics. NERC and the REs will work to identify specific correlations between system reliability performance metrics and RDA performance metrics.
9. NERC and all cross-border REs will work collaboratively to develop individual and joint metrics consistent with the separate Canadian Provincial MOUs or Agreements.
10. Separate budget related metrics exist that are used to examine the relative costs of Regional activities that are not included in these RDA metrics.



## Compliance Registration

### Metric:

NERC and the REs are administering<sup>1</sup> a process to proactively and routinely review, maintain, and validate registration status in a timely and risk-based manner to ensure that all users, owners, and operators that should be registered are registered for all appropriate functions.

### Measure:

Number of entities/functions found, through audits, events, or other means, to be registered that should not be registered, or not registered that should be registered. [Note: registration “gaps” or “overlaps” that are the result of changes to a registered entity’s functional responsibilities, changes in the definition of Bulk Electric System, transition to a JRO or CFR, or other factors that are outside the control of the RE, will not be counted in this measure.]

### Measure:

Average time to process uncontested entity requests to register or de-register for a function, in accordance with the NERC Rules of Procedure, measured from the time the entity makes the request to the time the request is approved by NERC, including intermediate steps; i.e., entity to RE, RE to NERC, NERC approval.

### Related ERO Enterprise Strategic Goal/Objective(s)

**Goal/Objective 5.f** — *Modify the registration program to be more efficient, risk-based, and aligned with reliability benefit, including evaluation of options such as increased granularity in registration by requirement or by assets for entities with limited impacts on bulk power system reliability.*

**Goal/Objective 5.g** — *Provide greater assurance that bulk power system owners, operators, and users are correctly registered through more proactive review of registration status; ensure that responsibilities are clearly understood by all registered entities and there are no material gaps or adverse impacts on bulk power system reliability.*

## Compliance Audits

### Metric:

Thorough, efficient, risk-focused, and effective compliance audits of registered entities for all applicable standards requirements, based on the RE’s risk/performance analysis plus other high-risk standards identified by NERC. Standards planned to be covered by the audit will be communicated in advance to the registered entity, however the RE may expand the scope of the audit to include other standards that are applicable to the registered entity consistent with the CMEP.

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<sup>1</sup> While we are working towards more of a risk-based focus, registration is currently conducted under the Compliance Registry and applicable ROP that focus on identifying and registering functions. As such, current practice is largely far more mechanical and prescriptive than risk-based.

Measure:

Audit Observation Scorecard completed by NERC staff with sufficient training and credentials to conduct evaluations of RE audits based on objective, standardized evaluation criteria. [Note: NERC and the REs need to establish common, agreed upon criteria for these evaluations that focus on the essential purpose of audits and the over-arching goal of identifying risks and improving reliability.]

Measure:

Percent satisfaction with the quality of the audit, professionalism of the auditors, and due process of the audit, as reported by registered entities on a post-audit questionnaire jointly develop agreed upon by NERC and the REs.

Related ERO Enterprise Strategic Goal/Objective(s)

**Goal/Objective 2.g** — *Internalize risk-based approaches into ERO programs, priorities, and initiatives to maximize reliability benefits and improve efficiencies.*

**Goal/Objective 6.e** — *Develop highly qualified and trained staffs at NERC and the regional entities, including enhancement of qualifications in auditing, investigations, enforcement, and other essential staff roles; consider staff exchanges where appropriate.*

**Enforcement**

Metric:

Thorough, complete, and timely reporting and processing of all required information by RE and NERC, in accordance with expectations in RDAs and Compliance Monitoring and Enforcement Program (CMEP.)

Measure:

Number of active violations divided by 6-month rolling average number of violations processed per month by BOTCC. [“Caseload Index” measures both the size of the remaining caseload and the average monthly rate at which violations are processed. For example, if the caseload as of January 1, 2011 was 3,000, and the average monthly rate at which violations were processed from July 1, 2010 to December 31, 2010 was 100, the “Caseload Index” would be 30.0.]

Measure:

Percent of NERC enforcement filings (Settlements, Administrative Citations, NOCVs, Dismissals, etc.) remanded or significant clarifications requested in writing by government regulators.

Measure:

Percent of enforcement proceedings (Settlements, Administrative Citations, NOCVs, Dismissals, etc.) remanded or significant clarifications requested by BOTCC. Includes those items that BOTCC has given NERC staff discretion to handle without BOTCC review.

Related ERO Enterprise Strategic Goal/Objective(s)

**Goal/Objective 5.a** — *Develop further enhancements to achieve efficient and timely enforcement compliance outcomes, including streamlined procedures for lower risk violations and improved workflow and tools at NERC and regional entities; target minor violations within three months and major cases within one year of discovery.*

**Goal/Objective 5.d** — *Achieve greater consistency across the ERO in the determination of violations and exercise of discretion in setting penalties and sanctions through a defined framework and training of applicable staff personnel.*

**Mitigation of Compliance Violations**

Metric:

Timeliness of compliance violation mitigation.

Measure:

Six-month rolling average time to mitigate compliance violations, from deem date to closure, with separate measures and trends for violations of different VRF/VSLs and different reliability risk significance. [Note: those cases in which long lead-time purchases of equipment, labor contract negotiations, scheduled outages of equipment, etc. affect the time to closure will be excluded from this measure.]

Related ERO Enterprise Strategic Goal/Objective(s)

**Goal/Objective 5.e** — *Ensure timely and thorough mitigation of all violations of mandatory reliability standards.*

**Event Analysis**

Metrics:

Pursuant to the NERC Rules of Procedure<sup>2</sup>, registered entities are tasked with conducting comprehensive analyses of events that reflect the severity of the incident. REs coordinate with NERC on event analyses to support the effective and efficient use of the collective industry resources, ensure consistency in event analysis and timely delivery of event analysis reports, and dissemination to the electric industry lessons learned and other information obtained or resulting from event analysis.

Measure:

Percent of completed detailed Event Analysis reports made available to the industry's technical community. [Note: Some restrictions on access to these reports may be imposed to protect CEII and confidential information.]

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<sup>2</sup> These Rules of Procedure changes are planned to be filed with FERC for approval in November 2011.

Measure:

Number of days to complete Event Analysis reports (by event category/severity) and close out by RE and NERC, separately.

Measure:

Benefit of Lessons Learned rated by registered entities (S/U) – % Satisfactory (S) Ratings on (1) positive impact on reliability and (2) cost-effective risk management. [Measures both NERC and RE performance. NERC and REs to develop framework and definitions for rating process.]

Related ERO Enterprise Strategic Goal/Objective(s)

**Goal 2** — *Bulk power system owners, operators, and users demonstrating sustained cultures of learning and reliability excellence, building upon underlying foundations of compliance and effective risk management.*

**Goal/Objective 2.a** — *Enable and encourage bulk power system owners, operators, and users to conduct periodic internal self-assessments to improve reliability and compliance, to share results for others to learn, to complete timely mitigation, and to self-report as required.*

**Goal/Objective 2.b** — *Provide a comprehensive event analysis program that engages bulk power system owners, operators, and users in determining root causes, lessons learned, and other improvement opportunities; ensure all events meeting defined criteria are catalogued, prioritized, and assessed for improvement opportunities.*

**Goal/Objective 2.c** — *Manage a consistent program for issuing recommendations and essential actions, and track and report mitigation results; modify ERO rules of procedure if needed to ensure alerts and recommendations are effective and ensure adequate technical and policy review for alerts and recommendations.*

**Goal/Objective 2.i** — *Maintain an easily accessible library of lessons learned from event analyses, best practices, examples of excellence, and other resources for reliability improvement.*

**Reliability Standards/Regional Standards**

Metric:

NERC and Regional Entities fully follow, and coordinate as necessary, their respective standards development processes to establish clear, results-based reliability standards that provide for an adequate level of reliability.

Measure:

Percent of NERC Board approved Reliability Standards that are results based with requirements providing clearly identified performance expectations and cost-effective reliability benefits.

Related ERO Enterprise Strategic Goal/Objective(s)

**Goal 1b.** — *Achieve a technically sufficient set of results-based reliability standards, with each requirement providing a clearly identified performance expectation and reliability benefit.*

**Reliability Assessment**

Metric:

NERC and RE processes for developing high-quality, thorough and timely assessments of the reliability of the Bulk-Power System.

Measure:

Regional Reliability Assessment Scorecard, jointly developed and agreed to by NERC and REs, to include items such as: (1) accuracy of data and information; (2) timeliness and clarity of NERC requests and RE submittals; (3) clarity of NERC requests and thoroughness of RE self-assessments; etc.

Related ERO Enterprise Strategic Goal/Objective(s)

**Goal/Objective 3.d** — *Continue to deliver high quality long-term and seasonal reliability assessments of the future adequacy of the bulk power system to operate reliably.*

**Update on Regulatory Matters  
(As of April 21, 2011)**

**Action Required**

None

**Regulatory Matters in Canada**

1. Negotiation ongoing with the Régie and NPCC regarding implementation of mandatory standards in Québec.
2. Adoption of NERC Reliability Standards pending in Nova Scotia.
3. Adoption of NERC Reliability Standards ongoing in Alberta.
4. Implementing regulations being developed in Manitoba.
5. Implementing regulations being developed in British Columbia.

**FERC Orders Issued Since the Last Update**

1. January 21, 2011 – Order on Notices of Penalty – The Commission issued an order on notices of penalty that it will review no further. *NP11-60-000* New Hope Power Partnership; *NP11-61-000* Lee County Resource Recovery Facility; *NP11-62-000* City of Clarksdale, Mississippi; *NP11-63-000* Unidentified Registered Entity; *NP11-64-000* Unidentified Registered Entity; *NP11-65-000* Mississippi Delta Energy Agency; *NP11-66-000* Coos-Curry Electric Cooperative, Inc.; *NP11-67-000* Umatilla Electric Cooperative Assoc.; *NP11-68-000* Lane Electric Cooperative, Inc./PNGC; *NP11-69-000* Consumer's Power, Inc.; *NP11-70-000* Unidentified Registered Entity; *NP11-71-000* City Of Minden; *NP11-72-000* Unidentified Registered Entity; *NP11-73-000* Montana-Dakota Utilities Company; *NP11-74-000* PPL Generation LLC; *NP11-75-000* Edison Mission Marketing & Trading, Inc.; *NP11-76-000* Unidentified Registered Entity; *NP11-77-000* Great River Energy; *NP11-78-000* The Dayton Power and Light Company; *NP11-79-000* Unidentified Registered Entity; *NP11-80-000* Morris Cogeneration, LLC; *NP11-81-000* Unidentified Registered Entity
2. February 2, 2011 – Letter Order Approving Interpretation to Reliability Standard CIP-001-1, Requirement R2. *Docket No. RD10-11-000*
3. February 2, 2011 – Letter Order Granting Clarification on Order No. 742 Regarding System Personnel Training Reliability Standards. *Docket No. RM09-25-001*
4. February 2, 2011 – Letter Order Accepting NERC's July 25, 2008 Compliance Filing listing Reliability Standards for transmission owners and transmission operators applicable to New Harquahala Generating Company, LLC. *Docket No. RC08-4-002*
5. February 2, 2011 – Letter Order Accepting Interpretation of CIP-005-1 Section 4.2.2 and Requirement R1.3. *Docket No. RD10-12-000*

6. February 2, 2011 – Letter Order Accepting NERC’s December 17, 2010 Compliance Filing on 2011 Business Plan and Budgets. *Docket No. RR10-13-001*
7. February 17, 2011 – Order Dismissing Request for Extension Regarding WestConnect Utilities request to extend the time period in which to comply with the requirements of certain MOD Reliability Standards. *Docket No. RM08-19-004*
8. February 18, 2011 – Order No. 733-A – Order granting several requests for clarification and grants rehearing, in part, and denies rehearing, in part, of the Final Rule in Order No. 733 which approved and directed modifications to the Transmission Relay Loadability Reliability Standard PRC-023-1. *Docket No. RM08-13-001*
9. February 28, 2011 – Order on Notice of Penalty – The Commission issued an Order stating it would not further review the July 6, 2010 Notice of Penalty regarding an Unidentified Registered Entity. *Docket No. NP10-140-000*
10. March 1, 2011 – Letter Order accepting NERC's January 10, 2011 uncontested filing in response to July 12, 2010 and December 1, 2010 Commission Orders Relating to Compliance Monitoring and Enforcement Agreements among SERC, FRCC and SPP RE. *Docket Nos. RR10-7-002, RR10-11-002*
11. March 1, 2011 – Letter Order Accepting NERC's January 24, 2011 Supplemental Budget and Funding Request for Texas Reliability Entity, *Docket No. RR10-13-002*
12. March 2, 2011 – Order on Notices of Penalty – The Commission issued an Order stating that it would not further review, on its own motion, the following Notices of Penalty in *Docket Nos. NP11-82-000* Castleton Power, LLC; *NP11-83-000* Granite Ridge Energy, LLC; *NP11-84-000* Sharyland Utilities, LP; *NP11-85-000* Scurry County Wind LP; *NP11-86-000* Western Area Power Administration – Sierra Nevada Region; *NP11-87-000* Sierra Pacific Power Company; *NP11-88-000* Mirant Potrero, LLC; *NP11-89-000* Arizona Public Service Company; *NP11-90-000* Gila River Power, LP; *NP11-91-000* Emerald People's Utility District; *NP11-92-000* Mason County PUD No. 3; *NP11-93-000* Lea County Electric Cooperative, Inc.; *NP11-94-000* Stanton Wind Energy, LLC; *NP11-95-000* City of Austin dba Austin Energy; *NP11-96-000* City of Lake Worth; *NP11-97-000* E.ON U.S. Services Inc. for the LG&E and KU Companies; *NP11-98-000* Unidentified Registered Entity; *NP11-99-000* Borger Energy Associates, LP; *NP11-100-000* South Carolina Public Service Authority; *NP11-101-000* Southern Illinois Power Cooperative; *NP11-102-000* Unidentified Registered Entity; and *NP11-103-000* Sam Rayburn G&T Electric Cooperative Inc.
13. March 3, 2011 – Notice of No Further Review of Initial Administrative Citation Notice of Penalty. *Docket No. NP11-104-000*
14. March 10, 2011 – Order Denying Rehearing of Nebraska Public Power District’s petition regarding Rule 1208. *Docket No. RR10-11-001*

15. March 10, 2011 – Order dismissing NERC’s September 9, 2010 proposed CIP Implementation Plan applicable to nuclear power plants as moot given the Nuclear Regulatory Commission’s November 26, 2010 letter regarding the regulation of cyber security at commercial nuclear power plants. *Docket No. RM06-22-014*
16. March 17, 2011 – Order 743-A – Order denying rehearing and otherwise reaffirming its determinations in Order No. 743 regarding the revisions to the definition of Bulk Electric System. *Docket No RM09-18-001*
17. March 17, 2011 – Order approving proposed revisions to NERC's Rules of Procedure, specifically a revision that provides an alternative means for developing or modifying a Reliability Standard in response to a Commission directive, including the Board’s development of a draft Reliability Standard, in the event that the regular development process fails to produce a responsive Reliability Standard. *Docket No. RR09-6-003*
18. March 17, 2011 – Order No. 746 – Final Rule Approving Regional Reliability Standard IRO-006-WECC-1 and six associated new definitions submitted to the Commission for approval. *Docket No. RM09-19-000*
19. March 17, 2011 – Order No. 747 – Final Rule Approving Planning Resource Adequacy Assessment Standard BAL-502-RFC-02 and four regional reliability definitions. *Docket No. RM10-10-000*
20. March 17, 2011 – Order No. 748 – Final Rule Approving Interconnection Reliability Operating Limits Standards IRO-008-1, IRO-009-1, and IRO-010-1a and proposed revisions to Reliability Standards EOP-001-1, IRO-002-2, IRO-004-2, IRO-005-3, TOP- 003-1, TOP-005-2, and TOP-006-2. *Docket No. RM10-15-000*
21. March 17, 2011 – Order No. 749 – Final Rule Approving Three System Restoration Reliability Standards EOP-001-1, EOP-005-2, EOP-006-2, and definition of the term “Blackstart Resource.” *Docket No. RM10-16-000*
22. March 17, 2011 – Order affirming the penalty in the Notice of Penalty Regarding Turlock Irrigation District. *Docket No. NP10-18-000*
23. March 25, 2011 – Order on Notices of Penalty – The Commission issued an Order stating that it would not further review, on its own motion, the following Notices of Penalty in Docket Nos. *NP11-105-000* Gainesville Regional Utilities; *NP11-106-000* Unidentified Registered Entity; *NP11-107-000* Burney Forest Products; *NP11-108-000* Avista Corporation; *NP11-109-000* Cedar Falls Utilities; *NP11-110-000* Allegheny Power; *NP11-111-000* Unidentified Registered Entity; *NP11-112-000* Consumers Energy Company; *NP11-113-000* Montana-Dakota Utilities Company; *NP11-114-000* Texas Municipal Power Agency; *NP11-115-000* BASF Corp.; *NP11-116-000* Unidentified Registered Entity; *NP11-117-000* Nevada Sun-Peak, LP; *NP11-118-000* Terra-Gen Dixie Valley, LLC; *NP11-119-000* Coso Finance Partners; *NP11-120-000* Coso Energy Developers; *NP11-121-000* Coso Power Developers; *NP11-122-000* PPG Industries, Inc.; *NP11-*



123-000 Covanta Fairfax, Inc.; NP11-124-000 Unidentified Registered Entity; NP11-125-000 Unidentified Registered Entity; NP11-126-000 Dogwood Energy, LLC; NP11-127-000 Unidentified Registered Entity; and NP11-128-000 Unidentified Registered Entity.

24. March 25, 2011 – Order on Notices of Penalty – The Commission issued an Order stating that it would not further review, on its own motion, the following Notices of Penalty in Docket Nos. NP11-129-000 Vandolah Power Company, LLC; NP11-130-000 City of Santa Clara; NP11-131-000 Pacific Gas & Electric Co.; NP11-132-000 Tampa Electric Company; and NP11-133-000 Administrative Citation Notice of Penalty.
25. April 12, 2011 – Order approving the December 23, 2010 compliance filing in response to the October 1, 2010 order pertaining proposed changes to Appendix 4D of the NERC Rules of Procedures. *Docket No. RR10-1-004*
26. April 12, 2011 – Data Request regarding the February 10, 2011 petition seeking approval of the Critical Infrastructure Protection Reliability Standards, Version 4. *Docket No. RM11-11-000*
27. April 21, 2011 – Order approving the Reliability Standard EOP-008-1. *Docket No. RD11-4-000*
28. April 21, 2011 – Order No. 752 – Final Rule approving the Version One Regional Reliability Standard for Transmission Operations (TOP-007-WECC-1). *Docket No. RM09-14-000*
29. April 21, 2011 – Order No. 751 – Final Rule approving the Version One Regional Reliability Standards for Facilities Design, Connections, and Maintenance; Protection and Control; and Voltage and Reactive (FAC-501-WECC-1, PRC-004-WECC-1, VAR-002-WECC-1, VAR-501-WECC-1). *Docket No. RM09-9-000*
30. April 21, 2011 – Order No. 750 – Final Rule approving the Interpretations of Interconnection Reliability Operations and Coordination and Transmission Operations Reliability Standards (TOP-005-1 and IRO-005-1). *Docket No. RM10-8-000*
31. April 21, 2011 – Notice of Proposed Rulemaking proposing to approve Interpretation of Transmission Operations Reliability Standard (TOP-001-1 Requirement R8). *Docket No. RM10-29-000*
32. April 21, 2011 – Order approving Reliability Standards IRO-006-5 and IRO-006-EAST-1. *Docket No. RD11-2-000*
33. April 21, 2011 – Notice of Proposed Rulemaking of Proposed Rulemaking proposing to amend Section 1281 of the Energy Policy Act of 2005 to facility price transparency in markets for the sale and transmission of electric energy in interstate commerce. The Commission proposes to require individual market participants to file, if applicable, a sub-set of e-Tag information, specifically e-Tag IDs, as part of the Electric Quarterly Reports (“EQRs”) because market participants are able to match their e-Tag IDs with the transactions they are required to report in the EQR. *Docket No. RM10-12-000*

34. April 21, 2011 – Notice of Proposed Rulemaking of Proposed Rulemaking proposing to revise the Commission’s regulations to require NERC to provide to Commission staff, on an ongoing basis, access to complete electronic tagging data used to schedule the transmission of electric power in wholesale markets. *Docket No. RM11-12-000*

### **NERC Filings Since the Last Update**

1. January 13, 2011 – Petition for Approval of IRO-006-5 and IRO-006-EAST-1, Glossary Term, and Implementation Plan. *Docket No. RD11-2-000*
2. January 14, 2011 – Comments in opposition to the request for extension of compliance date and request for expedited consideration of the Westconnect Utilities. *Docket No. RM08-19-000*
3. January 24, 2011 – Comments in response to Notice of Proposed Rulemaking on System Restoration Reliability Standards. *Docket No. RM10-16-000*
4. January 24, 2011 – Comments in response to Notice of Proposed Rulemaking on Interconnection Reliability Operating Limits Reliability Standards. *Docket No. RM10-15-000*
5. January 24, 2011 – Petition for approval of Amendment to the 2011 Business Plan and Budget of Texas Reliability Entity, Inc. and Amendment to Exhibit E to the Delegation Agreement. *Docket No. RR10-13-002*
6. January 26, 2011 – Letter to FERC regarding WestConnect Utilities request for eighteen-month extension of compliance date and request for expedited consideration of the MOD Reliability Standards approved by the Commission in Order No. 729. *Docket No. RM08-19-000*
7. January 28, 2011 – Petition for Approval of a Facilities Design, Connections, and Maintenance Reliability Standard FAC-013-2. *Docket No. RD11-3-000*
8. January 31, 2011 – Informational Filing of NERC analysis of NERC Standard Process Results Fourth Quarter 2010. *Docket No. RR06-1-000 and RR09-7-000*
9. January 31, 2011 – Notices of Penalty regarding the following entities in *Docket Nos. NP11-82-000* Castleton Power, LLC; *NP11-83-000* Granite Ridge Energy, LLC; *NP11-84-000* Sharyland Utilities, LP; *NP11-85-000* Scurry County Wind LP; *NP11-86-000* Western Area Power Administration – Sierra Nevada Region; *NP11-87-000* Sierra Pacific Power Company; *NP11-88-000* Mirant Potrero, LLC; *NP11-89-000* Arizona Public Service Company; *NP11-90-000* Gila River Power, LP; *NP11-91-000* Emerald People’s Utility District; *NP11-92-000* Mason County PUD No. 3; *NP11-93-000* Lea County Electric Cooperative, Inc.; *NP11-94-000* Stanton Wind Energy, LLC; *NP11-95-000* City of Austin dba Austin Energy; *NP11-96-000* City of Lake Worth; *NP11-97-000* E.ON U.S. Services Inc. for the LG&E and KU Companies; *NP11-98-000* Unidentified Registered Entity; *NP11-99-000* Borger Energy Associates, LP; *NP11-100-000* South Carolina Public Service

Authority; *NP11-101-000* Southern Illinois Power Cooperative; *NP11-102-000* Unidentified Registered Entity; and *NP11-103-000* Sam Rayburn G&T Electric Cooperative Inc.

10. February 1, 2011 – Administrative Citation Notice of Penalty. *Docket No. NP11-104-000*
11. February 7, 2011 – Comments in response to Notice of Proposed Rulemaking on Interpretations to IRO-005-1 and TOP-005-1 Reliability Standards. *Docket No. RM10-8-000*
12. February 10, 2011 – Petition for Approval of Critical Infrastructure Protection (CIP) Reliability Standards Version 4, associated implementation plans, and Violation Risk Factors and Violation Severity Levels. *Docket No. RD11-11-000*
13. February 11, 2011 – Petition for Approval of One Emergency Preparedness and Operations Reliability Standard EOP-008-1 and Retirement of EOP-008-0. *Docket No. RM11-11 -000*
14. February 18, 2011 – Compliance Filing in response to October 21, 2010 Order including revised pro forma delegation agreement, revised Sections 100-1600 of the Rules of Procedure, revised Appendix 4A to the Rules of Procedure and revised Appendix 4C to the Rules of Procedure. . *Docket No. RR10-11-003*
15. February 22, 2011 – Status Report Regarding BAL-004-1 Time Error Correction Reliability Standard. *Docket No RM09-13-000*
16. February 22, 2011 – Comments in response to Notice of Proposed Rulemaking Concerning Regional Reliability Standards FAC-501-WECC-1, PRC-004-WECC-1, VAR-002-WECC-1 and VAR-501-WECC-1. *Docket No. RM09-9-000*
17. February 22, 2011- Compliance Filing in response to the January 6, 2011 Order approving NERC’s November 20, 2009 Petition for Approval of two Reliability Standards revisions to Withdraw Midwest ISO Waivers. *Docket No RD10-4-001*
18. February 23, 2011 – Notices of Penalty regarding the following entities in *Docket Nos. NP11-105-000* Gainesville Regional Utilities; *NP11-106-000* Unidentified Registered Entity; *NP11-107-000* Burney Forest Products; *NP11-108-000* Avista Corporation; *NP11-109-000* Cedar Falls Utilities; *NP11-110-000* Allegheny Power; *NP11-111-000* Unidentified Registered Entity; *NP11-112-000* Consumers Energy Company; *NP11-113-000* Montana-Dakota Utilities Company; *NP11-114-000* Texas Municipal Power Agency; *NP11-115-000* BASF Corp.; *NP11-116-000* Unidentified Registered Entity; *NP11-117-000* Nevada Sun-Peak, LP; *NP11-118-000* Terra-Gen Dixie Valley, LLC; *NP11-119-000* Coso Finance Partners; *NP11-120-000* Coso Energy Developers; *NP11-121-000* Coso Power Developers; *NP11-122-000* PPG Industries, Inc.; *NP11-123-000* Covanta Fairfax, Inc.; *NP11-124-000* Unidentified Registered Entity; *NP11-125-000* Unidentified Registered Entity; *NP11-126-000* Dogwood Energy, LLC; *NP11-127-000* Unidentified Registered Entity; and *NP11-128-000* Unidentified Registered Entity.

19. February 25, 2011 – Comments in response to Notice of Proposed Rulemaking on Interpretation to Reliability Standard PRC-005-1. *Docket No. RM10-5-000*
20. February 28, 2011 – Fourth Quarter 2010 Compliance Filing in Response to Paragraph 629 Of Order No. 693 and requests to terminate the compliance filing obligation. *Docket No. RM06-16-000*
21. February 28, 2011 – Notices of Penalty regarding the following entities in Docket Nos. NP11-129-000 Vandolah Power Company, LLC; NP11-130-000 City of Santa Clara; NP11-131-000 Pacific Gas & Electric Co.; NP11-132-000 Tampa Electric Company; and NP11-133-000 Administrative Citation Notice of Penalty.
22. March 2, 2011 – Comments in response to Notice of Proposed Rulemaking on the Integration of Variable Energy Resources. *Docket No. RM10-11-000*
23. March 16, 2011 – Informational Filing in response to FERC's September 16, 2010 Order regarding NERC's Three Year Performance Assessment. *Docket Nos. RR09-7-000 and AD10-14-000.*
24. March 18, 2011 – Petition for approval of a Protection and Control (PRC) Reliability Standard PRC-023-2 and approval of a proposed addition to the NERC Rules of Procedure, Section 1700 – Challenges to Determinations. This filing satisfies certain directives the Commission issued in Order No. 733 pertaining to developing modifications to PRC-023-1. *Docket No. RM11-16-000*
25. March 21, 2011 – Supplemental Information to the NERC Compliance Filing in response to the Order on Violation Severity Levels Proposed by the ERO. *Docket Nos. RR08-4-000, RR08-4-001, RR08-4-002, and RR08-4-005*
26. March 21, 2011 – Comments following the February 8, 2011 Technical Conference on Priorities for Addressing Risks to the Reliability of the Bulk-Power System. *Docket No. AD11-6-000*
27. March 21, 2011 – Compliance Filing in response to January 20, 2011 Order on Violation Risk Factors and Violation Severity Levels for Critical Infrastructure Protection Reliability Standards. *Docket No. RD10-6-001, RD09-7-003*
28. March 30, 2011 – Petition for approval of a Proposed Modification to Protection System Definition. *Docket No. RM11-19-000*
29. March 31, 2011 – Petition for approval of Proposed New Reliability Standards and Implementation Plans Related to Under-Frequency Load-Shedding PRC-006-1 and EOP-003-2 and requests FERC approval for implementation plans that call for the retirement of PRC-006-0, PRC-007-0, PRC-009-0 and EOP-003-1. *Docket No. RM11-20-000*

30. March 31, 2011 – Petition for approval of four Transmission Planning System Performance Reliability Standards TPL-001-1, TPL-002-1b, TPL-003-1a, and TPL-004-1 and the retirement of TPL-001-0.1, TPL-002-0b, TPL-003-0a, and TPL-004-0. *Docket No. RM11-18-000*
31. March 31, 2011 – Notices of Penalty regarding the following entities in *Docket Nos. NP11-134-000* Ft. Pierce Utilities Authority; *NP11-135-000* Public Utility District No. 1 of Snohomish County; *NP11-136-000* Unidentified Registered Entity; *NP11-137-000* Unidentified Registered Entity; *NP11-138-000* El Paso Electric Company; *NP11-139-000* Dynegy Arlington Valley, LLC; *NP11-140-000* Unidentified Registered Entity; *NP11-141-000* City of Anaheim; *NP11-142-000* People’s Utility District; *NP11-143-000* Unidentified Registered Entity; *NP11-144-000* City of McMinnville; *NP11-145-000* Unidentified Registered Entity; *NP11-146-000* Unidentified Registered Entity; *NP11-147-000* Public Utility District No. 1 of Snohomish County; *NP11-148-000* Imperial Irrigation District; *NP11-149-000* Unidentified Registered Entity; *NP11-150-000* Unidentified Registered Entity; *NP11-151-000* Public Utility District No. 2 of Grant County, Washington; *NP11-152-000* Calpine Energy Services; *NP11-153-000* Exelon Generation Company, LLC - Exelon Nuclear; *NP11-154-000* California Department of Water Resources; *NP11-155-000* Unidentified Registered Entity; *NP11-156-000* Unidentified Registered Entity; *NP11-157-000* Unidentified Registered Entity; *NP11-158-000* PSEG Fossil, LLC; *NP11-159-000* NextEra Energy Resources, LLC; *NP11-160-000* Dartmouth Power Associates, LP; and *NP11-161-000* Unidentified Registered Entity.
32. March 31, 2011 – Administrative Citation Notice of Penalty. *Docket No. NP11-162-000*
33. April 8, 2011 –NERC submitted comments in response to the SmartGrid Interoperability Standards and the issues raised at the January 31, 2011 technical conference. *Docket No. RM11-2-000*
34. April 12, 2011 – NERC submitted an errata to the February 10, 2011 petition for approval of the Critical Infrastructure Protection Reliability Standards, Version 4. *Docket No. RM11-11-000*
35. April 13, 2011 – NERC submitted a request for extension of time to respond to the April 12, 2011 Data Request regarding the February 10, 2011 petition for approval of the Critical Infrastructure Protection Reliability Standards, Version 4. *Docket No. RM11-11-000*
36. April 15, 2011 – NERC submitted a petition for approval of an interpretation to Reliability Standard TOP-002-2a Requirement R10. *Docket No. RM11-23-000*
37. April 15, 2011 – NERC submitted a petition for approval of interpretations to Reliability Standards PRC-004-1 Requirements R1 and R3 and PRC-002-1 Requirements R1 and R2. *Docket No. RM11-22-000*
38. April 18, 2011 – NERC, FRCC, MRO, NPCC, SPP RE, Texas RE and WECC submitted a Request for Clarification, or in the Alternative, Rehearing and Motion to Intervene out-of-time of FRCC, MRO, NPCC, SPP RE and Texas RE regarding the Turlock Irrigation District Notice of Penalty Order. *Docket No. NP10-18-002*

39. April 18, 2011 – NERC submitted a Request for Clarification of Order No. 749 regarding the System Restoration Reliability Standards (EOP-001-1, EOP-005-2 and EOP-006-2). *Docket No. RM10-16-001*
40. April 18, 2011 – NERC submitted a Request for Clarification of Order No. 748 regarding the Interconnection Reliability Operating Limits Reliability Standards (IRO-008-1, IRO-009-1, IRO-010-1a, EOP-001-1, IRO-002-2, IRO-004-2, IRO-005-3, TOP-003-1, TOP-005-2 and TOP-006-2). *Docket No. RM10-15-001*
41. April 21, 2011 – NERC submitted response to NPPD and SPP RE petitions for review of the NERC BOT's denial of NPPD's registration transfer request. *Docket No. RR11-1-000.*

## Anticipated NERC Filings

1. April 22, 2011 – NERC may submit reply comments in response to the comments submitted on April 8, 2011 regarding the SmartGrid Interoperability Standards and the issues raised at the January 31, 2011 technical conference. *Docket No. RM11-2-000*
2. May 16, 2011 –WECC must conduct spot checks for the purposed of testing continued compliance by Turlock Irrigation District and, if appropriate, Modesto Irrigation District. NERC and WECC must submit the results of the spot check to FERC. *Docket No. NP10-18-000*
3. June 20, 2011 – (Approximate date) WECC is to file WECC’s criteria for identifying and modifying major transmission paths listed in the WECC Transfer path Table. WECC will post any revisions to the WECC Transfer Path Table on the WECC website, with concurrent notification to FERC, NERC and industry. *Docket Nos. RM09-14-000 and RM09-9-000*
4. June 20, 2011 – (Approximate date) NERC must submit comments in response to the Notice of Proposed Rulemaking regarding the Interpretation of TOP-001-1 Requirement R8. *Docket No. RM10-29-000*
5. June 20, 2011 – (Approximate date) WECC must consider modifications to the Violation Risk Factors and Violation Severity Levels assigned to FAC-501-WECC-1, PRC-004-WECC-1, VAR-002-WECC-1, and VAR-501-WECC-1. WECC must submit revisions or explanations justifying these Violation Risk Factors and Violation Severity Levels. *Docket No. RM09-9-000*
6. June 20, 2011– (Approximate date) NERC must submit comments in response to the Notice of Proposed Rulemaking regarding the Interpretation of TOP-001-1 Requirement R8. *Docket No. RM10-29-000*
7. June 20, 2011– (Approximate date) NERC must submit comments in the response to the Notice of Proposed Rulemaking regarding NERC being required to provide Commission staff with non-public access to complete e-Tag data. *Docket No. RM11-12-000*
8. June 20, 2011– (Approximate date) NERC must submit comments in the response to the Notice of Proposed Rulemaking regarding individual market participants being required to file, if applicable, a sub-set of e-Tag information, specifically e-Tag IDs, as part of the Electric Quarterly Reports (“EQRs”) because market participants are able to match their e-Tag IDs with the transactions they are required to report in the EQR. *Docket No. RM10-12-000*
9. August 19, 2011 – (Approximate date) NERC must submit revised Violation Risk Factors for Requirements R1 and R2 and revised Violation Severity Levels for TOP-007-WECC-1. *Docket No. RM09-14-000*
10. September 28, 2011 – NERC must submit an annual informational report (the first) regarding the TFE program (see October 1, 2010 Order). The report is a “consistency” report and must be submitted until the Commission has approved a uniform framework for appraising the

reliability benefits of strict compliance when making the section 3.1(iv) and (vi) determinations. *Docket No. RR10-1-001*

11. January 25, 2012 – NERC must submit a filing within one year of the January 25, 2011 effective date of the November 18, 2010 Order regarding the Revision to ERO Definition of the BES, NERC. Order No. 743, *Docket No. RM09-18-000*
12. May 22, 2012 –NERC and WECC must submit a revised Standard that includes the Violation Severity Levels associated with each requirement of the revised BAL-004-WECC-1 Standard (See May 21, 2009 Order) (See November 22, 2010 NERC submittal). *Docket No. RM08-12-000*
13. February 17, 2013 – NERC must comply with directives in Order No. 733 for filing the test and the results from a representative sample of utilities in each of the three Interconnections (see February 17, 2011 Order No. 733-A). *Docket No. RM08-13-001*