NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Agenda
Planning Committee Meeting

June 7, 2011 | 1–5 p.m.
June 8, 2011 | 8–noon

Marriott Toronto Airport
901 Dixon Rd
Toronto, ON
M9W1J5 Canada
(416) 674-9400

1. **Administrative***
   a. Welcome and Introductions – Chair Tom Burgess
   b. Notice of Public Meeting – Secretary

      "Participants are reminded that this meeting is public. Notice of the meeting was posted on the NERC website and widely distributed. Participants should keep in mind that the audience may include members of the press and representatives of various governmental authorities, in addition to the expected participation by industry stakeholders."
   c. Arrangements – Secretary
   d. Parliamentary Procedures – Secretary
   e. Announcement of Quorum – Secretary
   f. NERC Antitrust Compliance Guidelines – Secretary
   g. Future Meetings – Secretary
      i. September 13–14, 2011 – St. Louis, MO (confirmed)
      ii. December 13–14, 2011 – Atlanta, GA (confirmed)
   h. Agenda Approval – Chair Burgess

2. **Consent Agenda***
   a. **Approve** – March 8-9, 2011 Draft PC Meeting Minutes as final Minutes – Secretary

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3. Chairman's Remarks

a. Report on May 10–11, 2011 NERC Board of Trustees and Member Representatives Committee Meetings - Chair Burgess

4. Information Only*

a. System Planning from a Canadian Perspective – Ric Cameron

b. Eastern Interconnection Wide Area SynchroPhasor Angles Baselining Study – Mahendra Patel, PJM Interconnection

c. Improved Processes and Procedures for Interconnection-wide Modeling – Mark Lauby

d. Consolidating Various Reliability Assessments, Measures, and Reports – John Moura

e. ERCOT February 2, 2011 Grid Emergency Events – Kent Saathoff, VP operations and planning, ERCOT ISO

5. Committee Matters*

a. **Approval** – Revised draft of PC Strategic Plan and PC Charter changes – Vice Chair Jeff Mitchell

   i. Review PC Next -Steps and Future Work Plan draft and comments received

   ii. Discuss approval process for Work Plan and implementation plans

b. **Approval –** Revisions to PC Report Approval Process and proposed changes to PC Charter – Secretary

c. **Discuss** – PC proposed procedures for NERC Alerts – Secretary

d. **Discuss** – Development of OC-PC-SC proposal to address resolution of ALR-Reliability Principles – "BES/ALR Policy Issues Task Force" – Chair Burgess

e. **Discuss –** NERC response to FERC sponsored report by LBNL, "Use of Frequency Response Metrics to Assess the Planning and Operating Requirements for Reliable Integration of Variable Renewable Generation" – Bob Cummings

f. **PC Elections –** Elections of Chair and Vice Chair – Chair Burgess

   i. Call for Chair nominations

   ii. Election of Chair

   iii. Call for nominations for Vice Chair

   iv. Election of Vice Chair

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6. Subgroup Reports*

	PC Action	Presentation
a. Reliability Assessment Subcommittee	PC to complete Risk Assessment by July 30, 2011	RAS Chair Mark Kuras/John Moura
1. Load Forecasting Working Group	Status Report	
b. Reliability Metrics Working Group	1. Feedback – 2011 Reliability Performance Report 2. Feedback and approve posting of Integrated Reliability Index (IRI) concepts whitepaper 3. Approve – Letter from PC/OC to request TOs provide data to support ALR1-5 System Voltage Analysis Performance for key BES nodes	RMWG Chair Bill Adams
c. Integration of Variable Generation Task Force	Provide comments on the report “Potential Bulk System Reliability Impacts of Distributed Resources” by June 30, 2011	Mark Lauby/IVGTF Co-Chairs John Dumas /Hardev Juj
d. Geomagnetic Disturbance Task Force	Status Report	GDMTF Chair Donald Watkins
e. Resource Issues Subcommittee	Review comments on response matrix and final GADSTF report	RIS Chair Kevan Jeffries
1. Loss-of-Load Expectation Working Group	Status Report	
2. Generating Availability Data System Task Force	Endorse report for BOT approval	GADSTF Chair Ben Crisp

f.	Transmission Issues Subcommittee	1. Approve - TIS Frequency Response Assignment Scope of Work 2. Approve - TIS recommendation of the frequency response criteria 3. Approve - TIS collaboration with the System Protection and Control Subcommittee (SPCS) on their review of standards related to Special Protection Systems and Remedial Action Schemes	TIS Chair Mark Byrd/Bob Cummings
1.	Model Validation Task Force	Approve – posting draft procedures for modeling development and validation	Bob Cummings
g.	System Protection and Control Subcommittee	1. Approve – posting of SPCS guideline: "Transmission System Phase Backup Protection" 2. Approve – Coordination with TIS to address failure of special protection systems	Bill Miller
h.	Data Coordination Subcommittee	Status Report	DCS Chair Mark Kuras
1.	Transmission Availability Data Systems Working Group	1. Approve TADSWG to work on a draft request for comments (under Rules of Procedure 1600) on reporting 100-199kV outages in webTADS beginning January 1, 2014.	TADSWG Chair Mike Pakeltis
2.	Demand Response Data Task Force	Status Report	DRDTF Chair Sharon Bauer
3.	Data Coordination Working Group	Status Report	

i.	Spare Equipment Database Task Force	Feedback - SEDTF white paper by June 30, 2011	SEDTF Chair Dale Burmester
j.	Smart Grid Task Force	Status Report	
k.	Events Analysis Working Group	Status Report	EAWG Chair Jacquie Smith

*Background material is included

Agenda Item 1.a.
Planning Committee
June 7–8, 2011

Welcome and Introductions

Action Required
Information only

Background
Please see the following:

1. **Attachment 1** – the Planning Committee's Membership.
2. **Attachment 2** – the Planning Committee's full roster with contact information.
3. **Attachment 3** – the Planning Committee's organizational chart showing all PC subgroups.

Planning Committee Membership – 2010-2012

Name	Member (Term)
1. Investor-owned utility	David Weaver, PECO, an Exelon Company (12) Teresa Mogensen, Xcel Energy, Inc. (11)
2. State/municipal utility	Stuart Nelson, Lower Colorado River Authority (12) Richard Anderson. Fayetteville (NC) Public Works Department (11)
3. Cooperative utility	Jay Farrington, PowerSouth Energy Cooperative (12) Paul McCurley, National Rural Electric Cooperative Association (11)
4. Federal or provincial utility/Federal Power Marketing Administration	Christian Deguire, Hydro Québec TransÉnergie[1] (12) Ron Mazur, Manitoba Hydro[1] (12) Bing Young, Hydro One Networks, Inc. (11) Richard Pendergrass, Bonneville Power Administration (11)
5. Transmission dependent utility	Kevin Koloini, American Municipal Power (12) Tom Reedy, Florida Municipal Power Association (11)
6. Merchant electricity generator	Scott Helyer, Tenaska, Inc. (12) Kris Zadlo, Invenergy LLC (11)
7. Electricity marketer	Vacant (2 positions)
8. Large end-use electricity customer	Vacant (2 positions)
9. Small end-use electricity customer	Stacia Harper, Ohio Partners for Affordable Energy (12) Len Januzik, AMEC Earth and Environmental (11)
10. Independent system operator/ regional transmission organization	Dan Rochester, IESO (12) Mark Westendorf, Midwest ISO (11)
11. Regional reliability organization[2]	ERCOT Dan Woodfin, ERCOT FRCC Ben Crisp, Progress Energy Florida MRO Dale Burmester, American Transmission Company, LLC NPCC Phil Fedora, NPCC RFC Paul Kure, ReliabilityFirst Corporation SERC Russell Schussler, Georgia Transmission Corporation SPP Noman Williams, Sunflower Electric Power Corporation WECC Branden Sudduth, WECC
12. State government	Christine Ericson, Illinois Commerce Commission (12) Jeff Kaman, Iowa Utilities Board (11)
Officers	Chairman Thomas C. Burgess, FirstEnergy Corp (11) Vice Chairman: Jeff Mitchell, ReliabilityFirst Corporation (11)
Government representatives[2]: U.S. federal government Canadian federal government Provincial government	 Jesus M. Sierra, FERC Vacant (1 position) Vacant (1 position) Peter Fraser, Ontario Energy Board

[1] Elected to satisfy NEL ratio requirement for Canadian members.

[2] Appointed.

Planning Committee

Chairman	Thomas C. Burgess Director, FERC Compliance	FirstEnergy Corp. 76 South Main Street Akron, Ohio 44308	(330) 384-5225 (330) 761-4388 Fx burgesst@ firstenergycorp.com
Vice Chairman	Jeffrey L. Mitchell Director - Engineering	ReliabilityFirst Corporation 320 Springside Dr. Suite 300 Akron, Ohio 44333	(330) 247-3043 (330) 456-3648 Fx jeff.mitchell@ rfirst.org
Investor Owned Utility	Teresa Mogensen Vice President, Transmission	Xcel Energy, Inc. 250 Marquette Ave, 8th Floor Minneapolis, Minnesota 55401	(612) 330-7947 (612) 573-1815 Fx teresa.m.mogensen@ xcelenergy.com
Investor Owned Utility	Dave Weaver Director, Transmission Operations & Planning	Exelon Corporation 2301 Market Street N2-6 Philadelphia, Pennsylvania 19103	(215) 841-5060 (215) 841-6319 Fx david.weaver@ peco-energy.com
State/Municipal	Richard Anderson, PE Electrical Systems Engineer Manager	Fayetteville Public Works Commission 955 Old Wilmington Road P.O. Box 1089 Fayetteville, North Carolina 28302	(910) 323-2990 rick.anderson@ faypwc.com
State/Municipal	Stuart Nelson Manager, Asset Development	Lower Colorado River Authority P.O. Box 220 Austin, Texas 78767	(512) 369-4413 (512) 369-4413 Fx stuart.nelson@ lcra.org
Cooperative	Paul McCurley Manager, Power Supply and Chief Engineer	National Rural Electric Cooperative Association 4301 Wilson Boulevard MC EP11-252 Arlington, Virginia 22203-1860	(703) 907-5867 (703) 907-5517 Fx paul.mccurley@ nreca.coop
Cooperative	Jay Farrington Manager, T&D Planning and Reliability	PowerSouth Energy Cooperative P.O. Box 550 Andalusia, Alabama 36420	(334) 427-3225 (334) 488-4903 Fx jay.farrington@ powersouth.com
Federal/Provincial	Christian Deguire Manager Planning and Strategies Bulk Power System	Hydro-Quebec TransEnergie	(514) 879-4100 Deguire.Christian@ hydro.qc.ca
Federal/Provincial	R. W. Mazur Manager, System Planning Department	Manitoba Hydro 12-1146 Waverly Street P.O. Box 815 Winnipeg, Manitoba R3C 2P4	(204) 474-3113 (204) 477-4606 Fx rwmazur@ hydro.mb.ca
Federal/Provincial	Richard M. Pendergrass Manager, Power and Operations Planning	Bonneville Power Administration 905 NE 11th Avenue Portland, Oregon 97232	503.230.7666 503.230.3939 Fx rpendergrass@ bpa.gov

Federal/Provincial	Bing Young Director - Transmission System Development	Hydro One Networks, Inc. 483 Bay St 15th Floor, North Tower Toronto, Ontario M5G 2P5	416-345-5029 bing.young@ HydroOne.com
Merchant Electricity Generator	Scott M. Helyer Vice President, Transmission	Tenaska, Inc. 1701 E. Lamar Blvd. Suite 100 Arlington, Texas 76006	(817) 462-1512 (817) 462-1510 Fx shelyer@tnsk.com
Transmission Dependent Utility	Kevin Koloini	1111 Schrock Rd., Suite 100 Columbus, Ohio 43229	(614) 540-1111 (614) 540-1113 Fx kkoloini@ amppartners.org
Transmission Dependent Utility	Thomas Reedy	Florida Municipal Power Agency 8553 Commodity Circle Orlando, Florida 32828	(407) 355-7767 tom.reedy@ fmpa.com
	Stacia Harper Director, Regulatory Affairs and Public Policy	Ohio Partners for Affordable Energy 231 West Lima Street P.O. Box 1793 Findlay , Ohio 45839-1793	(614) 282-5260 (614) 466-9475 Fx sharper@ ohiopartners.org
Merchant Electricity Generator	Kris Zadlo, P.E. Vice President	Invenergy LLC One South Wacker Drive Suite 2020 Chicago, Illinois 60606	(312) 582-1532 (312) 224-1444 Fx kzadlo@ invenergyllc.com
Electricity Marketer	To Be Named		
Large End-Use Electricity Customer	To Be Named		
Small End-Use Electricity Customer	Len Januzik Senior Director	Quanta Technology 1255 Prestwick Lane Itasca, Illinois 60143	(630) 531-5127 (630) 799-0291 Fx ljanuzik@ quanta- technology.com
ISO/RTO	Dan Rochester, P. Eng. Manager - Reliability Standards and Assessment	Independent Electricity System Operator Station A, Box 4474 Toronto, Ontario M5W 4E5	(905) 855-6363 (905) 403-6932 Fx dan.rochester@ ieso.ca
ISO/RTO	Mark Westendorf Technical Manager	Midwest ISO, Inc. 701 City Center Drive P.O. Box 4202 Carmel, Indiana 46082-4202	(317) 517-5829 (317) 249-5994 Fx mwestendorf@ midwestiso.org
RRO-ERCOT	Dan M Woodfin Director, System Planning	Electric Reliability Council of Texas, Inc. 2705 West Lake Dr. Taylor, Texas 76574	(512) 248-3115 (512) 248-4235 Fx dwoodfin@ ercot.com
RRO-FRCC	Ben Crisp Director System Planning and Regulatory Performance	Progress Energy Florida 6565 38th Avenue North St. Petersburg, Florida 33710	(727) 344-4190 ben.crisp@ pgnmail.com

RRO-MRO	Dale Burmester Manager, Major Projects/Transmission Planning	American Transmission Company, LLC 2 Fen Oak Court Madison, Wisconsin 53718	(608) 877-7109 (608) 444-2447 Fx dburmester@ atcllc.com
RRO-NPCC	Phil Fedora Assistant Vice President, Reliability Services	Northeast Power Coordinating Council, Inc. 1040 Avenue of the Americas (6th Ave) 10th Floor New York, New York 10018-3703	(212) 840-4909 (212) 302-2782 Fx pfedora@npcc.org
RRO-RFC	Paul D. Kure Senior Consultant, Resources	ReliabilityFirst Corporation 320 Springside Drive Suite 300 Akron, Ohio 44333	(330) 247-3057 (330) 456-3648 Fx paul.kure@ rfirst.org
RRO-SERC	Russell Schussler Vice President, System Planning	Georgia Transmission Corporation 2100 East Exchange Place Tucker, Georgia 30084	(770) 270-7565 russell.schussler@ gatrans.com
RRO-SPP	Noman Lee Williams V.P. Transmission Services & Engineering Sunflower Electric Power Corp.	Sunflower Electric Power Corporation W 301 13th Street P.O. Box 1020 Hays, Kansas 67601	(785) 623-3332 (620) 272-5413 Fx NWilliams@ sunflower.net
RRO-WECC	Branden Sudduth Manager, Planning Services	Western Electricity Coordinating Council 615 Arapeen Dr Ste. 210 Salt Lake City , Utah 84108	(801) 883-6888 (801) 582-3918 Fx branden@wecc.biz
State Government	Christine Ericson Deputy Solicitor General	Illinois Commerce Commission	cericson@ icc.illinois.gov
State Government	Jeff Kaman Manager, Energy Section	Iowa Utilities Board	Jeff.Kaman@ iowa.gov
U.S. Federal (Non-voting)	Jesus M. Sierra Group Manager	Federal Energy Regulatory Commission 888 First Street NE Washington, D.C. 20426	(202) 502-8479 (202) 219-2836 Fx nano.sierra@ ferc.gov
U.S. Federal (Non-voting)	To Be Named		
Canadian Federal (Non-voting)	To Be Named		
Provincial (Non-voting)	Peter Fraser Special Advisor	Ontario Energy Board 2300 Yonge St., 26th Floor Toronto, Ontario M4P 1E4	(416) 440-7616 (416) 440-7656 Fx peter.fraser@ oeb.gov.on.ca

Planning Committee

Chair: Thomas C. Burgess
Vice Chair: Jeffery L. Mitchell

Transmission Issues Subcommittee (TIS)

Chair: Mark Byrd
V. Chair: Dana Walters

- **Model Validation Task Force (MVTF)**
  Chair: Jose Conto
- **Reliability Fundamentals Working Group (RFWG)**
  Chairs: Peter Brandien
  (Joint with the Operating Committee)
- **Smart Grid Task Force (SGTF)**
  Chair: Paul McCurley
- **Spare Equipment Database Task Force (SEDTF)**
  Chair: Dale Burmester
  V. Chair: Mark Westendorf

Data Coordination Subcommittee (DCS)

Chair: Mark J. Kuras
V. Chair: Paul Kure

- **Transmission Availability Data System Working Group (TADSWG)**
  Chair: Mike Pakeltis
  V. Chair: Julian Cox
- **Demand Response Data Task Force (DRDTF)**
  Chair: Vacant
- **Data Coordination Working Group (DCWG)**
  Chair: K.R. (Chuck) Chakravarthi

Reliability Assessment Subcommittee (RAS)

Chair: Mark Kuras
V. Chair: Vince Ordax

- **Load Forecasting Working Group (LFWG)**
  Chair: Robert D. Mariotti

Resource Issues Subcommittee (RIS)

Chair: Kevan Jefferies
V. Chair: Gary Brinkworth

- **Loss-of Load Expectation Working Group (LOLEWG)**
  Chair: Andrew Ford
- **Generating Availability Data System Task Force (GADSTF)**
  Chair: Ben Crisp

System Protection and Control Subcommittee (SPCS)

Chair: Jonathan Sykes
V. Chair: William Miller

- **Reliability Metrics Working Group (RMWG)**
  Chair: Bill Adams
  V. Chair: Jerry Rust
  (Joint with the Operating Committee)
- **Integration of Variable Generation Task Force (IVGTF)**
  Co-Chairs
  John Dumas and Hardev Juj
  (Joint with the Operating Committee)
- **Geomagnetic Disturbance Task Force (GMDTF)**
  Chair: Donald Watkins
  V. Chair: Frank Koza
  (Joint with the Operating Committee)
- **Event Analysis Working Group (EAWG)**
  Chair: Jacquie Smith
  V. Chair: Steve Ashbaker
  (Joint with the Operating Committee)

Revised: August 3, 2010 to add a chair to the GADSTF
Revised: August 26, 2010 to reflect the vacancy of the DRDTF chair.
Revised: September 15, 2010 to reflect the retirement of the RICCITF and the addition of the SEDTF and the GMDTF.
Revised: September 23, 2010 to reflect new TIS officers.
Revised: October 25, 2010 to reflect new SEDTF officers.
Revised: December 8, 2010 to reflect the SEDTF reporting to the PC.
Revised: January 3, 2011 to reflect the disbanding of the GTRPMTF.
Revised: January 7, 2011 to add officers to the GMDTF.

Schedule of Events
Standing Committee Meetings and other related Committees

June 6-9, 2011 – Toronto, Ontario

Group Name	Monday, June 6 Marriott Toronto Hotel	Tuesday, June 7 Marriott Toronto Hotel	Wednesday, June 8 Marriott Toronto Hotel	Thursday, June 9 Marriott Toronto Hotel
SIRTF	**SIRTF** 1 p.m. – 6 p.m. **Room: Alberta/Quebec**	**SIRTF** 8 a.m. – Noon **Room: Alberta/Quebec**		
EAWG	**EAWG** 10 a.m. – 7 p.m. **Room: Dixon**			
REMG		**REMG** 11 a.m. – Noon **Room: Salons GH**		
Operating Committee		**OC Exec Committee:** 9 a.m. – 11 a.m. **Room: British Columbia** **OC Working lunch** Noon – 1 p.m. **OC:** 1 p.m. – 5 p.m. **Room: Salon D**	**OC:** 7:30 a.m. – Noon **Room: Salon D**	
Planning Committee		**PC Exec Committee:** 9 a.m. – 11 a.m. **Room: Salon F** **PC Working lunch** Noon – 1 p.m. **PC:** 1 p.m. – 5 p.m. **Room: Salon E**	**PC:** 7:30 a.m. – Noon **Room: Salon E**	
Critical Infrastructure Protection Committee			**CIPC Working lunch** Noon – 1 p.m. **CIPC:** 1 p.m. – 5 p.m. **Room: Salon D** **CIPC Executive Committee:** 5 p.m. – 7 p.m. **Room: Dixon**	**CIPC:** 8 a.m. – Noon **Room: Salon D**
CATF				**CATF:** 1 p.m. – 5 p.m. **Room: Salon D**

Parliamentary Procedures

Based on Robert's Rules of Order, Newly Revised, 1990 Edition

Motions

Unless noted otherwise, all procedures require a "second" to enable discussion.

When you want to…	Procedure	Debatable	Comments
Raise an issue for discussion	Move	Yes	The main action that begins a debate.
Revise a Motion currently under discussion	Amend	Yes	Takes precedence over discussion of main motion. Motions to amend an amendment are allowed, but not any further. The amendment must be germane to the main motion, and cannot reverse the intent of the main motion.
Reconsider a Motion already approved	Reconsider	Yes	Allowed only by member who voted on the prevailing side of the original motion.
End debate	Call for the Question *or* End Debate	No	If the Chair senses that the committee is ready to vote, he may say "if there are no objections, we will now vote on the Motion." Otherwise, this motion is debatable and subject to 2/3 majority approval.
Record each member's vote on a Motion	Request a Roll Call Vote	No	Takes precedence over main motion. No debate required, but the members must approve by 2/3 majority.
Postpone discussion until later in the meeting	Lay on the Table	Yes	Takes precedence over main motion. Used only to postpone discussion until later in the meeting.
Postpone discussion until a future date	Postpone until	Yes	Takes precedence over main motion. Debatable only regarding the date (and time) at which to bring the Motion back for further discussion.
Remove the motion for any further consideration	Postpone indefinitely	Yes	Takes precedence over main motion. Debate can extend to the discussion of the main motion. If approved, it effectively "kills" the motion. Useful for disposing of a badly chosen motion that cannot be adopted or rejected without undesirable consequences.
Request a review of procedure	Point of order	No	Second not required. The Chair or secretary shall review the parliamentary procedure used during the discussion of the Motion.

Notes on Motions

Seconds. A Motion must have a second to ensure that at least two members wish to discuss the issue. The "seconder" is not recorded in the minutes. Neither are motions that do not receive a second.

Announcement by the Chair. The Chair should announce the Motion before debate begins. This ensures that the wording is understood by the membership. Once the Motion is announced and seconded, the Committee "owns" the motion, and must deal with it according to parliamentary procedure.

Revisions. Technically, revisions to the main motion are accomplished by the Amend procedure. However, immediately after making the motion, and before it is announced by the Chair, another member may ask that the motion be revised. If the original "motion-maker" agrees to the revision, then the revised motion will be the one debated. The original "seconder" need not be consulted, because the original "motion-maker" plus the "reviser" constitute a motion and a second.

Voting

Voting Method	When Used	How Recorded in Minutes
Unanimous Consent	When the Chair senses that the Committee is substantially in agreement, and the Motion needed little or no debate. No actual vote is taken.	The minutes show "by unanimous consent."
Vote by Voice	The standard practice.	The minutes show Approved or Not Approved (or Failed).
Vote by Show of Hands (tally)	To record the number of votes on each side when an issue has engendered substantial debate or appears to be divisive. Also used when a Voice Vote is inconclusive. (The Chair should ask for a Vote by Show of Hands when requested by a member).	The minutes show both vote totals, and then Approved or Not Approved (of Failed).
Vote by Roll Call	To record each member's vote. Each member is called upon by the Secretary,, and the member indicates either "Yes," "No," or "Present" if abstaining.	The minutes will include the list of members, how each voted or abstained, and the vote totals. Those members for which a "Yes," "No," or "Present" is not shown are considered absent for the vote.

Notes on Voting
(Recommendations from DMB, not necessarily Mr. Robert)

Abstentions. When a member abstains, he is not voting on the Motion, and his abstention is not counted in determining the results of the vote. The Chair should not ask for a tally of those who abstained.

Determining the results. The results of the vote (other than Unanimous Consent) are determined by dividing the votes in favor by the total votes cast. Abstentions are not counted in the vote and shall not be assumed to be on either side.

"Unanimous Approval." Can only be determined by a Roll Call vo te because the other methods do not determine whether every member attending the meeting was actually present when the vote was taken, or whether there were abstentions.

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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.

Future Meetings

Action Required
None – information only

Background
The Planning Committee's future meetings are scheduled as follows:

Date	Location
September 13–14, 2011	St. Louis, MO (confirmed)
December 13–14, 2011	Atlanta, GA (confirmed)

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Draft Minutes
Planning Committee

March 8, 2011 | 1–5 p.m.
March 9, 2011 | 8a.m. – noon

Phoenix Convention Center & Venues
100 N. 3rd Street
Phoenix, AZ 85004

Planning Committee (PC) Chair Thomas C. Burgess presided over the meeting. The meeting notice, amended agenda, and list of attendees are attached as **Exhibits A**, **B**, and **C**, respectively. Meeting presentations are posted at http://www.nerc.com/filez/pcmin.html.

Administrative Matters

Welcome and Introductions: Chair Burgess welcomed Mr. David W. Weaver of PECO Energy, as a new IOU Sector representative on the PC, and recognized the proxies for several absent members.

Process for Nominating PC Vice Chair: Chair Burgess reviewed the PC Charter provisions for nominating and electing the PC Vice Chair at the PC June 2011 meeting and noted that nominations would be accepted at the meeting.

Arrangements: Secretary A. J. Connor reviewed the arrangements and schedules for the two days of the meeting.

Parliamentary Procedures: Secretary Connor noted that the PC follows the Robert's Rules of Order newly revised as summarized in the posted meeting agenda package.

Face-to-Face Meeting Reminder: Secretary Connor discussed the following open meeting reminder:

> *Participants are reminded that this meeting is public. Notice of the meeting was posted on the NERC website and widely distributed. Participants should keep in mind that the audience may include members of the press and representatives of various governmental authorities, in addition to the expected participation by industry stakeholders.*

116-390 Village Blvd.
Princeton, NJ 08540
609.452.8060 | www.nerc.com

Quorum: Of the PC's 34 total voting member positions available, the PC has two vacancies in the large end-use customer sector and two vacancies in the electricity marketer sector, leaving 30 active voting members. The meeting quorum (two-thirds of 30) was satisfied by 27 voting members or their proxies being present. The following proxies attended the meeting for absent voting members: Mr. Ibrahim El Nahas for Mr. Bing Young (Federal/Provincial), Mr. Tony Norris for Mr. Rick Pendergrass (Federal/Provincial), Mr. Jean-Marie Gagnon for Mr. Christian Dequire (Federal/Provincial), Mr. Marc Tunstall for Mr. Rick Anderson (State/Municipal), and Mr. Puesh Kumar for Mr. Kevin Koloini (Transmission Dependent Utility).

Antitrust Compliance Guidelines: Secretary Connor reviewed the NERC Antitrust Compliance Guidelines.

Future Meetings: The PC future meetings are scheduled as follows:

June 7–8, 2011	Toronto, ON (confirmed)
September 13–14, 2011	St. Louis, MO (tentative)
December 13–14, 2011	Atlanta, GA (tentative)

Approval of Meeting Agenda: Chair Burgess reviewed the meeting agenda and noted that two items were being added (Agenda Items 5.i and 5.h) and noted that the timing of some agenda items may have to be discussed in different sequence to accommodate the schedules of the presenters. Mr. Ron Mazur, manager, system planning department, Manitoba Hydro, offered a motion that the agenda be approved as amended. The amended agenda was approved without dissent.

Consent Agenda: Secretary Connor stated that no comments had been received on the posted Planning Committee Draft Minutes - December 7–8, 2010 (Tampa, FL). Stuart Nelson, manager, asset development, Lower Colorado River Authority, offered a motion that the minutes be approved. The minutes were approved without dissent, with noted editorial changes to be made by the Secretary.

Chair's Remarks

Highlights of the February 16–17, 2011 Member Representatives Committee (MRC) and Board of Trustees (BOT) Meetings:

Chair Burgess noted the MRC and BOT meetings were focused on strategic planning and the alignment needed to improve emphasis on priority, focus and balance.

During the BOT Standards Oversight and Technology Committee (SOTC) open meeting, the Standards Committee's priorities and strategic goals were presented, along with the results of the priority tool.

The BOT Compliance Committee (BOTCC) discussed efforts to improve efficiency in the Compliance Application Notice (CAN) process and the Compliance Analysis Reports (CAR) efforts to describe factors contributing to the most violated standards. A forward looking effort is being initiated to facilitate implementation of new standards without the 'bow-wave' of initial violations, including a considering a trial period for standard compliance.

Chair Burgess presented the Risk Based Reliability Compliance concept at the BOT meeting. The concept was endorsed as consistent with the NERC Strategic Plan, and it was recommended that the concept be integrated into the plan as an objective. Gerry Cauley, NERC president and CEO, suggested a need for Compliance and Certification Committee involvement. The BOT and NERC management agreed that the concept should be refined and advanced, and coordinated with FERC and other regulators.

Roy Thilly was elected as a NERC Trustee and NERC Trustees Janice Case, Fred Gorbet, and Paul Barber were re-elected. Jim Goodrich retired from the board due to term limits.

Mr. Cauley reported on the FERC Technical Conference, titled *Priorities for Addressing Risks to the Reliability of the Bulk Power System*, held on February 8, 2011, focused on reliability priorities and continuing to improve reliability while delivering value to customers. The cost, benefits, and value component of the equation was discussed and an annual 'state of reliability system' summit with FERC was suggested, with the key focus on:

1. Updating ALR definition: load loss vs. cascading outages.
2. BES definition resolution.
3. Strategic Planning Process: four–seven strategic goals to drive objectives and tactics: a reliability technical focus needed with feedback from technical committees.
4. Expedited Reliability Standards development: consider forming small teams of SME, legal, regulatory, and compliance individuals to focus development, and then move to open stakeholder process. The pace of standards development is largest risk to the ERO.

Mr. Cauley also discussed the recent cold snap in TX, NM, and AZ: NERC's review of issues, causes, etc. with an eye to minimize the potential impact on reliability. FERC and others have launched similar reviews. The Facility Rating Alert was discussed. Thus far there has been good entity initial plans, progress, and are now on progressive path to address corridor clearances.

Herb Schrayshuen, NERC vice president and director of standards, reported on the Bulk Electric System definition development. The approach is to generally encompass all facilities necessary to operate the interconnected transmission network, eliminate regional discretion, and draw a 100 kV bright line. The Standard Drafting Team received 82 comments on the SAR, with key issues being: 1) scope of BES below 100kV (small resources) and 2) exemption process (modeling/studies processes need definition).

At the FERC Technical Conference, Mr. Cauley discussed formulating key reliability topics and proposed top eight issues. The next step is to prioritize and refine the Compliance Monitoring and Enforcement Program and audit programs to look at the most reliability significant aspects. The results of lessons learned from 160 events should be considered to guide reviews and evaluations, and eventually be replaced with hard data from TADS, GADS, and DADS.

Tom Galloway, NERC senior vice president and chief reliability officer, and Gerry Adamski, NERC director of situation awareness, reviewed the alert development process. An interim approach will be released in the first quarter of 2011 and changes to the NERC Rules of Procedure (RoP) will be recommended by the end of 2011. The objectives are to improve the alert system functions, the use of alerts, the distribution protocols, and after action reviews.

Dave Nevius, NERC senior vice president, addressed the various metrics activities being pulled together into an integrated approach. There are three basic efforts: bulk power reliability indicators, compliance performance metrics, and effectiveness metrics. The intent is to consider system events, reliability condition, standards, and organizational effectiveness, to drive elements to enhance reliability. The initial integrated reliability performance draft report will be provided in June 2011.

Mr. Cauley discussed the ERO Strategic Plan 2011–15. The plan describes seven overarching goals and 85 tasks. The goals include: 1) clear results based Standards that provide for an Adequate Level of Reliability, 2) owners-users-operators (O/U/O) reflect culture of learning/reliability excellence, built on compliance/risk management, 3) develop reliability performance measures/high quality assessments-emerging issues, 4) O/U/O effectively manage risks from cyber/physical attacks and HILF, 5) Independent efficient CMEP to provide feedback/incentives to registered entities, 6) execute statutory functions with Regional Entities collaborative/efficiently, and 7) exceptional reputation/trusted leader of reliability, high confidence. Mr. Cauley discussed meeting with the National Lab's, DOD, and ESCC, for a policy level discussion and to produce a set of initiatives that enhance credibility around security. These include partnering with NIST-DOE on some standards, and resolving with DHS-FERC-DOD-DOE what range of scenarios we are protecting against, including military installations. The national labs have developed certain aspects related to training, cyber certification, and network security monitoring, while NERC is increasingly providing sound insight and guidance on these matters. An open policy item involves resolving the appropriate roles of government and industry entities.

Information Only

Using SynchroPhasors to Improve Dynamic Models of Electrical Loads: Mr. Dmitry Kosterev, Bonneville Power Administration, gave a presentation (posted for Agenda Item 4.a) to provide an update on the North American SynchroPhasor Initiative (NASPI). The presentation described the need for, and development of, dynamic load modeling. Mr. Kosterev pointed out that static load models are no longer adequate. He described the impact of fault-induced delayed voltage recovery (FIDVR) events, and the differences between measurements made by system control and data acquisition systems, such as supervisory control and data acquisition (SCADA) and phasor measurement units (PMU). Mr. Kosterev also discussed the need for additional PMU-quality recordings of faults and FIDVR events in large load centers for load model validation. Ms. Alison Silverstein, project manager, North American SynchroPhasor Initiative (NASPI), provided an update on meeting plans for NASPI and the development of a five year roadmap. NASPI will be meeting June 8–9, 2011 in Toronto.

Sub-Synchronous Resonance and Controls Interaction: Bob Cummings, NERC director of system analysis and reliability initiatives, gave a presentation (posted for Agenda Item 4.b) on issues associated with sub-synchronous resonance, torsional interactions, and control instability associated with the use of series capacitors, power electronics, and wind turbines.

Mr. Paul Hassink, director west transmission planning, American Electric Power Service Corporation (AEPSC), discussed considerations associated with exposure of generation to Sub-Synchronous Resonance (SSR) and Sub-Synchronous Control Instability (SSCI) in ERCOT related to series compensated transmission lines (posted for Agenda Item 4.b). Mr. Hassink identified the interconnection issues, described events that had occurred and discussed possible resolutions. Mr. Cummings discussed the need for a whitepaper on SSR, SSTI, and SSCI, with a compendium of references on the subject matter. Dale Burmester, manager, major projects/transmission planning, American Transmission Company, LLC. and PC member made a motion that the Transmission Issues Subcommittee (TIS) develop the whitepaper. The motion carried without dissent.

NLE 2011: Matthew Light, Department of Energy (DOE), presented the National Level Exercise (NLE) 2011 for the New Madrid Earthquake Scenario to be performed the week of May 15, 2011 (posted for Agenda Item 4.c). The exercise will involve federal, state and local government officials, the private sector, and the general public. This exercise has been preceded by the Memphis Earthquake Workshop, involving several utilities exchanging best practices, and the State New Madrid Seismic Zone Webinar to provide information to the affected states. Mr. Light offered to provide a copy of the Workshop report to the PC.

Reliability, Survivability, and Resiliency-Self Assessment Tool (RSR-SAT): Mr. Light gave a presentation (posted for Agenda Item 4.d) on a pilot test of RSR-SAT being performed by the U.S. Department of Energy (DOE) Office of Electricity Delivery and Energy Reliability and follows a number of onsite assessments performed with the National Guard. Mr. Light pointed out that the pilot assessment was intended to be a less intrusive, voluntary program, focused on improving the understanding of the supply chains, the physical infrastructure, and business operations. The pilot working group would be established in about a month and would involve a group of less than 10 companies. He offered to send the PC a scoping document.

Committee Matters

NERC President's Top Priority Issues: Mark Lauby, NERC vice president and director of reliability assessment and performance analysis, presented a matrix of the NERC President's top eight priority issues for bulk power system reliability (posted for Agenda Item 5.a), and discussed recommended roles, primary and support, for the technical committees and subcommittees. Discussion focused on the basis of the selection of the top eight from the list of over 80 issues identified. It was suggested that a lists be developed of the top eight issues the PC is now addressing, and the top eight issues the PC is not now addressing. Mr. Lauby agreed to send the matrix and additional background information to the PC members and requested the PC members provide their comments by March 31, 2011.

ERO Strategic Goals: Mr. Lauby presented a draft of the ERO Strategic Goals through 2015 prepared by NERC and the Regional Entities (posted for Agenda Item 5.b) and discussed the areas being concentrated on by NERC staff. The timing of work on the various issues was discussed and it was suggested that the PC Strategic Plan Ad Hoc Team develop recommendations on priority and timing for presentation at the PC June 2011 meeting.

PC Report Review and Approval Process: Secretary Connor presented the draft Process for Planning Committee Approval of Reports developed by the PC Executive Committee (posted for Agenda Item 5.c) and requested PC approval of the process. Scott Helyer, vice president, transmission, Tenaska, Inc., offered a motion that the process be approved. The process was approved without dissent, with a proviso that the process be clarified to indicate that the PC will only endorse the use of NERC's Rules of Procedure Section 1600 – Requests for Data or Information requests for those reports initiated by the PC.

Draft Planning Committee Strategic Plan: Jeff Mitchell, PC vice chair, reviewed the draft PC Strategic Plan (posted for Agenda Item 5.d) developed by the PC Strategic Plan Ad Hoc Team and pointed out the correlation with the NERC ERO strategic plans. Suggestions were made to consider adding communications as a strategic issue, clarify that references to resources included transmission in addition to generation, and ensure that timelines developed for the strategic plan line up with the NERC ERO strategic plans. The strategic plan should be reviewed with the other NERC standing committees before being presented to the NERC BOT. Mr. Mitchell discussed the next steps required to complete the strategic plan and to develop any necessary modifications to the PC Charter. Stuart Nelson offered a motion that the PC Strategic Plan Ad Hoc Team complete the development of the PC Strategic Plan and present the plan to the PC for approval in June 2011. The motion was approved without dissent.

PC Proposal on NERC Alerts: Mr. Adamski gave a presentation on NERC Alerts Development – Draft Framework for Industry Engagement (posted for Agenda Item 5.e). He reviewed the interim approach being taken and noted that modifications to the NERC Rules of Procedure to accommodate a final procedure are to be completed by year end. He also discussed the need to develop a list of subject matter experts by topic and ensure they have the necessary security clearances to participate in alerts. Chair Burgess addressed the need to review the PC draft proposal on alerts and the draft framework presented by Mr. Adamski and develop a practical proposed process that would align the elements of the respective proposals. He asked the PC Executive Committee to follow up and revise the PC alert proposal as necessary. He also asked the PC members to provide comments on how best to develop and maintain the subject matter experts needed. Mr. Lauby asked the membership provide volunteers for the current NERC GMD Alert.

Initiative to Develop Proposal on Adequate Level of Reliability: Chair Burgess discussed recent activities and discussions at technical conferences regarding the definition of, and metrics for, an adequate level of reliability (ALR) for the bulk power system. He noted that the determination of a definition for ALR was linked to efforts to define the Bulk Electric System. He pointed out that discussions at recent technical conferences focused on resolving issues most important to reliability and some approaches were very costly. Therefore, the time was right to form a joint group from the Operating Committee, Standards Committee, and the PC with an objective of refining the description of ALR, integrating the Reliability Principles, and seeking approval from the NERC technical committees, the NERC Board of Trustees, and FERC. Chair Burgess requested comments and observations from the PC members and asked for volunteers to serve on the joint group. Jeff Kaman, manager, energy section, Iowa Utilities Board, agreed to provide a volunteer from the State Government sector. Mr. David Weaver from the Investor Owned Utility sector, Mr. Russ Schussler from the Regional Reliability Organization sector, and Vice Chair Mitchell volunteered.

Comprehensive Plan to Address Frequency Response: Mr. Cummings addressed the need to assemble a steering committee on frequency response and the need for volunteers from the PC to work with the volunteers from the Operating Committee. Subject matter experts are needed on frequency response and governor models. The PC discussed the activities on frequency response issues and whether there were other issues that needed to be addressed. It was noted that an important issue that needs to be addressed now is the acceptable level of frequency response for each of the Interconnections and on what contingency or other criteria should those levels be based. The relationship of this issue to the Lawrence Berkeley National Laboratory study was discussed as well, since that study outlines the elements of the issue and why a decision is needed. Chair Burgess asked the Transmission Issues Subcommittee to take the lead and recruit the other volunteers, as needed, to develop a recommended scope covering what criteria should be used to decide the appropriate level of interconnection-wide frequency response, and other related issues that need to be addressed. A draft of the scope is to be provided to the PC Executive Committee's for consideration in the next four to six weeks.

Comprehensive Comments Responding to FERC Report on LBNL: Director Cummings discussed the draft NERC comments being developed in response to the FERC report on the Lawrence Berkeley National Laboratory (LBNL) study. He agreed to send the NERC comments to the PC by the end of March, 2011 for review and comments by the PC. The response to FERC is due by May 6, 2011.

BES Definition Activities: Vice President Lauby discussed the comments related to defining the BES sent to the Operating Committee and PC for review and noted that responses were needed within two weeks. He also discussed the work of the Standards drafting team and RoP revisions group and the need to have a standard and RoP changes developed by year end.

Coordinated Action Plan - Critical Infrastructure Strategic Initiatives: Stuart Brindley, NERC consultant for the Electricity Sub-Sector Coordinating Council (ESSC), gave a presentation on the Coordinated Action Plan developed by the Joint Action Group (posted for Agenda Item 5.j). The Joint Action Group and the Coordinated Action Plan provide the organizational structure to work on the High Impact- Low Frequency (HILF) issues. Mr. Brindley pointed out that the Joint Action Group was committed to making rapid progress in identifying issues to be resolved. The task forces are being established, along with a work plan developed. The objectives are being developed and work on solutions is beginning. Alternative solution on GMD issues are expected to be delivered in 2011, followed by solutions for other HILF issues in 2012 and 2013.

Committee's Appreciation Letter: Mr. Jean-Marie Gagnon, project manager interconnected networks assets planning, Hydro-Quebec TransEnergie, introduced a motion that the PC thank John Seelke, former PC secretary, for his service. The motion was approved, without dissent, with the proviso that Mr. Gagnon and Chair Burgess would develop the wording of a letter to be sent to Mr. Seelke on behalf of the PC.

Subgroup Reports

Reliability Assessment Subcommittee (RAS): RAS Vice Chair, Vince Ordax, gave a presentation (posted for Agenda Item 6.a) addressing RAS activities associated with the Gas\Electric Interdependency Special Assessment, the 2011 Long-Term Reliability Assessment- Emerging Reliability Issues, and the Reliability Assessment Approval Webinars. Mr. Ordax pointed out that the objective of the Gas\Electric Interdependency Special Assessment was to review gas and electric interdependencies, assess challenges, identify areas of high vulnerability, and determine recommendations for enhancing reliability. He requested a review of the draft scope of the study and comments study design, scope, and methods by March 22nd. (see posting http://www.nerc.com/docs/pc/ras/DRAFT2011GasStudyScope.pdf). Comments should be submitted to: assessments@nerc.net.

Mr. Ordax reviewed the status of the 2011 Long-Term Reliability Assessment (LTRA) and pointed out that the RAS was developing and prioritizing a list of specific emerging issues to be addressed. He requested input from other PC subgroups on the emerging issues assessment, and stated that the RAS will submit the top issues to the PC for their risk ranking at the June Meeting, and the LTRA would be presented to the PC at the September meeting.

Mr. Ordax reviewed the RAS proposals to enhance the seasonal reliability assessment approval process and noted the RAS is recommending a special dedicated web conference for approval of the assessments, following a reasonable comment and review period. The proposed schedule for the web conferences are as follows:

2011 Summer Reliability Assessment	May 13, 2011
2011 Long-Term Reliability Assessment	October 11, 2011
2011/2012 Winter Reliability Assessment	November 8, 2011

Mr. Ordax requested approval of the conference dates. Chair Burgess requested the RAS ensure the PC has the proposed assessments two weeks prior to the conferences. Mr. Nelson made a motion that the conference dates be approved. The motion passed without dissent.

Reliability Metrics Working Group (RMWG): Jeff Mitchell, vice chair, gave a presentation on Reliability Metrics and Integrated Risk Assessment (posted for Agenda Item 6.b) covering the refinement of the Severity Risk Index (SRI), the development of an Integrated Reliability Index (IRI), and an annual State of Reliability report to communicate the effectiveness of reliability improvement programs and provide an integrated view of risk. He noted that the SRI concepts and framework was approved by the Operating Committee and PC in September 2010. Refinements are based on TADS and Electricity Supply & Demand (ES&D) data, interconnection daily peak loads, and sensitivity studies using 2008 and 2009 outage and event information.

The objective for development of an IRI is to identify measures for determining achievement of reliability goals, provide reliability improvement measures, and provide goals that define an ALR. The IRI will incorporate three factors: (1) Key Reliability Indicators (MI) - metrics covering major factors impacting reliability, (2) an Event Risk Index (RI) - risk associated with major events, and (3) a Compliance Index (CI) – Reliability Standards that have high levels of impact on reliability. Mr. Mitchell discussed the efforts underway to develop the three factors and outlined the future work for the RMWG.

Mr. Mitchell reviewed the scope of the development of a State of Reliability Report/Reliability Performance Report and noted that the intent was to provide quarterly updates on a website, publish an annual report, and provide annual webinars to discuss the assessment of bulk power system reliability performance and metrics. The intent is to provide an integrated view of risk, covering critical infrastructure protection, Reliability Standards Development, and compliance event analysis. He reviewed the work plan and indicated a draft of the report would be provided to the Operating Committee and PC for review in June 2011.

Mr. Mitchell requested the PC approve SRI refinement and scope change, including a change in the name of the report. He also requested feedback on the IRI concept. The PC discussion issues related to combining the three IRI factors vs. tracking all three to gain experience. Mr. Lauby committed to have NERC staff provide suggestions to the PC at the June meeting. Mr. Stuart Nelson offered a motion endorsing the refinement of the SRI. The motion was approved without dissent. Mr. Noman Williams made a motion that the scope be changed, including a change in the report name. The motion was denied. Chair Burgess asked the RMWG to consider how the SRI/IRI should be reported and bring any needed change in scope to the June meeting.

Mr. Mitchell reviewed the coordination with the RCWG on ALR1-5 and the need to collect data associated with identified key 345 kV and above buses/nodes and the associated TOs/TOPs. He said the RMWG recommends the Operating Committee and PC write a letter to the TOs/TOPs for voluntary data submittals starting 3rd quarter of 2011. The PC approved the request to write a letter with the Operating Committee.

Integration of Variable Generation Task Force (IVGTF): Mr. Lauby discussed the report included in the meeting agenda materials (posted for Agenda Item 6.c). The report discusses the known characteristics of regional variable generation and practices to predict variable generation output potential and capacity contribution during peak-demand hours, and provides a framework for determining the contributions and best use of variable generation on the bulk power system. Mr. Lauby requested approval of the report for posting. Mr. Russell Schussler made a motion that the report be approved. The motion passed without dissent.

Geomagnetic Disturbance Task Force (GMDTF): GMDTF Chair, Don Watkins, presented a GMDTF status presentation (posted for Agenda Item 6.d.1). He reported that the GMDTF had held its first face-to-face meeting on February 28–March 1, 2011 and outlined the task force deliverables in 2011. In addition, the GMDTF subgroups and NERC staff are developing a list of prevention and mitigation steps to counteract geomagnetic disturbance events and working on an industry wide conference to address this issue in April 2011.

Generating Availability Data Systems Task Force (GADTF): GADSTF Chair, Ben Crisp, gave a presentation on Mandatory Reporting of Conventional Generation Performance Data – GADS (posted for Agenda Item 6.e.3) and discussed the need to understand how the changes resource mix and performance impacts planning reserve margins. He pointed out that understanding the performance of existing and new types of resources is necessary in determining the reliability of the bulk power system and approximately 300 GW is not currently reported to GADS, and approximately 50 percent of generation added in 2000–2008 is not reporting. Mr. Crisp outlined a schedule to start collecting the data in the first quarter of 2012, and requested the PC approve the report *Mandatory Reporting of Conventional Generation Performance Data* to be posted as a NERC RoP Section 1600 request for industry comments. Discussion by the PC pointed out several concerns about expanding mandatory data requests into the equipment level, usefulness of the additional data for various studies, and coordination among the regions to avoid duplication of requests. The importance of a designative reporting entity (e.g., Canadian Electric Association or Independent Service Operators) being able to provide information on behalf of stakeholder groups was also discussed. This was duly noted and will be added to the final data required. Mr. Helyer offered a motion to approve posting the report as a Section 1600 request for comments, though the PC does not endorse the report at this time. The motion passed without dissent. The GADSTF was requested to provide a review of the comments received at the PC June meeting.

Transmission Issues Subcommittee (TIS) and its subgroup, the Model Validation Task Force (MVTF): TIS Chair, Mark Byrd, provided a status report for the TIS and the MVTF. He noted that a task team had been formed to review MOD-010 through MOD-015 and prepare recommendations and measures for a SAR, plans to partner with WECC on a modeling workshop in June, and to hold two modeling workshops before the end of 2011.

Mr. Cummings gave a presentation on the MVTF work plan progress and changes (posted for Agenda Item 6.f.1). The work plan tasks on powerflow and dynamics validation procedures are to be posted for comments in April, 2011 and are expected to be presented to the PC for approval at the June 2011 meeting. The tasks on operational planning - offline models procedure draft is expected to be posted for comments in April and brought to the PC for approval in December, 2011. Schedules had changed for several future tasks.

System Protection and Control Subcommittee (SPCS): SPCS Chair, Jonathan Sykes, provided a status report for the subcommittee. The SPCS posted the guideline, *Transmission System Phase Backup Protection,* for industry comment in January and the comment period ended on February 28. The SPCS plans to review the comments and submit a document for approval by the PC at the June meeting.

The completion of a white paper, with TIS, on the response of protective relays to power swings, has been extended until September 2011 due to work on the Relay Loadability Order and other activities. SPCS and TIS have identified methods that may be useful in identifying transmission lines subject to tripping during stable power swings and system simulations are being performed to screen the methods.

A SPCS sub-team reviewed breaker failure issues, based on the October 10, 2010 Lesson Learned, and related IEEE guides, and concluded that IEEE guidance on this subject is appropriate. The sub-team is drafting a report for consideration at the June 2011 PC meeting.

The SPCS provided technical support, and proposed misoperation categories and cause codes, to the ERO-RAPA Group developing a common template to be used in all regions for misoperation reporting.

Data Coordination Subcommittee (DCS): DCS Chair, Paul Kuras, provided a status report. The subcommittee continues to work on resolving conclusions in the whitepaper concerning the detail to include in simulation models and who should be responsible for submitting the modeling data. The DCS and TIS are examining the MOD Reliability Standards to determine who will be collecting data.

Transmission Availability Data System Working Group (TADSWG): TADSWG Chair, Mike Petalkis, provided a status report. TADSWG is still evaluating options for incorporating 100-199kV data collection based on EIA's intent to collect such data and an anticipated revision to the BES definition. Issues have been raised regarding the approved timeline for a Section 1600 Major Change not being responsive to the EIA-411 2014 proposal for collecting 100-199kV data. An expedited change process or a delay in the data collection for one year by the EIA would be required. Three dimensions to collecting 100-199kV data have to be considered: the best platform to collect the data, the elements that should be reported, and, which outages are to be reported. The TADSWG has decided to survey registered transmission owners to determine the impact for reporting 100-199kV outage data. The results of the survey will be evaluated at the upcoming May 2011 TADSWG meeting. The TADSWG will bring an action item to the June PC meeting to determine how or if to proceed with collecting the data at that time.

The TADSWG 2010 calendar year reports (NERC and 8 Regions) will be the first to include Automatic and Non-Automatic Outage data and are now targeted for presentation for approval at the September 2011 PC meeting. The requirement for additional data validation, preparation, and publication time necessitated the delay into the third quarter.

The need for additional analysis, potential additional data collection, and a change in scope, was discussed. Mr. Helyer made a motion that the TADSWG, in coordination with Mr. Lauby, consider the value of additional analysis and data collection and bring a proposal to the June meeting covering any change in scope required. The motion was approved without dissent.

Demand Response Data Task Force (DRDTF): The status report for the DRDTF was provided in the advance agenda materials. Discussion and actions were not necessary during this meeting. Chair Burgess noted that a Chair is needed for the task force and ask the PC members to provide him volunteers for the position.

Data Coordination Working Group (DCWG): The status report for the DCWG was provided in the advance agenda materials and discussion and actions were not necessary during this meeting.

Spare Equipment Database Task Force (SEDTF): SEDTF Chair, Dale Burmester, provided a presentation (posted for Agenda Item 6.h.4) and gave an update on the establishment of the task force and relationship to the Coordinated Action Plan. The task force will recommend a uniform approach to collecting, storing, and distributing information on long-lead time BES spare equipment. The task force will consider building upon existing pooling or bilateral equipment sharing programs. The pilot program to request information on spares is expected to be voluntary. If participation is less than 70 percent after one year, may pursue a RoP Section 1600 mandatory request.

Smart Grid Task Force (SGTF): SGTF Chair, Paul McCurley, gave an update on the task force. Requests have been made for feedback from the technical committees on specific topics to be addressed in response to the Smart Grid Follow-On Activity 1 (Integration of smart grid devices and systems into the bulk power system requiring new planning and operating tools, models, and analysis techniques) and Activity 2 (Integration of smart grid devices/systems changing the character of the distribution system). Input is needed on the modeling functions to support initial elements on distribution and bulk power system components. Vice President Lauby will contact the MVTF concerning these areas.

Event Analysis Working Group (EAWG): EAWG Chair. Jacquie Smith, provided a status report and gave a presentation (posted for Agenda Item 6.j) on the program. She covered Phase 1 of the Field Trial that ended in January 2011, and provided metrics on event category frequency by region, along with descriptions of the events. She also discussed the lessons learned prior to the events and lessons learned as a result of the Field Trial. Phase II starts April 15, 2011 and will be preceded by a Webinar. Phase II will include the following new procedures:

- Event notification within 24 hours of occurrence
- Data hold for Category 2 or above events
- Event reporting analysis timeline – complete within 10 days of notice
- Regional Entities complete Event Analysis Report and compliance self evaluation for Cat 2 and above

Adjournment

Chair Burgess adjourned the meeting at 12 p.m. (Mountain).

Respectfully submitted,

A.J. Connor
Committee Secretary

PC - BOT COMMENTS:

1. Assessment of Reliability:

Overall, these reports address key provisions in S215 and thereby enhance the posture of NERC by continued focus on underlying technical reliability content and delivery of these reports in a meaningful and understandable fashion.

Appreciate the support of the /NERC Staff /RE's for the 450 volunteers in sub-groups supporting PC functions.

Impending Deliverables include the Summer Assessment report and are currently teeing up a suite of potential assessments for /MRC consideration. Based on the initial post season assessment, we slimmed down the approach to providing a review of the actual experience compared to the Summer Assessment – and use this to improve later seasonal assessments.

Looking forward, Emerging Issues process (carbon legislation, EPA regulations, frequency response, resource mix impacts, …) guides the next round of assessments from a long term strategic view. We are setting a more expansive approach to reflect assessment input and selection, determine follow-on actions, as well as simplify/streamline the resources needed for report preparation.

Continuous focused improvement in the quality/delivery of the Reliability Assessments and Scenario Reports. These are very significant and valuable deliverables of the ERO enterprise – the key is finding better ways to maintain alignment with overall strategic objectives and work collaboratively to enhance reliability.

2. Strategic Alignment:

Particularly pleased with a strong effort by current Vice Chair Jeff Mitchell. Three-fold approach to addressing strategic alignment –

1] serious review/evaluation of the NERC Top Priority Reliability Issues, and their relationship to actions and efforts being conducted within the PC – provided a direct matrix of alignment,

2] conducted a similar review of the ERO Strategic Objectives, comprised of seven (7) key elements, in particular alignment of the various tasks/objectives within the PC, and

3] following launch last fall, developed first-ever PC Strategic Plan that we intend to finalize at the June meeting.

It will result in an effective framework for the PC to provide sustainable overall guidance and direction consistent with this plan. Its development and alignment with ERO enterprise strategic goals prompts adjustments of the Charter, the Organization Structure, and the priority focus of the respective functions/efforts.

This combination of activities conveys a sense of the *initiatives and strategic alignment* among the technical committee leadership, the, and ESCC – that needs to be sustained through technical leadership/coordination and clear linkage with BOT and ESCC objectives. We welcome ongoing opportunities for greater BOT/MRC strategic alignment.

3. Technical Advances:

Invest in technical advances: T&D Probability methods – integrating probability and risk in generation and transmission assessments is well along in field deployment; Model validation/enhancement efforts to consolidate/unify data and models essential to assess reliability; frequency response modeling/dynamics efforts with OC; and planning applications of NASPI synchro-phasor deployments.

Launch significant efforts to address key reliability aspects. System protection improvements for relaying protection performance and protection for power swings; long-term frequency response modeling/analysis in concert with the OC; and model enhancement/validation efforts. Emphasis is on concerted coordinated efforts with defined work plans that target specific deliverables, and thereby provide a solid reliability technical foundation and reliability improvements in each of these areas. In some cases we are utilizing steering advisory groups to help provide sustainable guidance and direction.

4. Reliability Indices/Metrics:

In terms of *measuring the overall reliability performance*, the PC is supporting development of integrated metrics through the RMWG, with the objective of aligning and expanding insight about the reliability state of the BES. The IRI under development is a method to integrate reliability index measures for bulk system performance using metrics and trends. The current focus is on simplifying and streamlining the metrics, such that the key indicators providing the greatest insight are maintained, and other less relevant or duplicative items discarded – leading to a periodic “state of reliability report”.

The GADS TF is developing an optimal approach for gathering reliability data for models/trends, along the lines of TADS.

Preliminary joint OC, PC, SC, CIPC efforts to revisit the ALR definition, in light of FERC Technical conference observations, and ensure that it reflects convergence with the SC Reliability Principles.

5. Greater SCCG Coordination:

We continue to *enhance the coordination among technical committees* to align/support overall reliability objectives. As an example, the PC reflects SC rankings of standards projects such that technical foundation work can be initiated that will then expedite development of results-based standards, produce efficiency/results value, focus on fundamental reliability impacts, and align with 3yr RSDP. These utilize the technical expertise of the PC, OC, and CIPC to collaborate/support the Standards Committee in the development of sound technically solid reliability standards.

The development of the *ESCC Strategic Roadmap and establishment of the Technical Steering Group* comprised of OC, PC, CIPC officers is an important advance, providing the strategic framework for guidance/direction to address HILF actions. Several Task Forces formed to address these items, including the Spare Equipment TF, the Severe Impact Resilience TF, and the GMD TF are making good progress. A key success component will be sustaining coordination between the ESCC and the TSG leadership team.

6. Alerts/Advisories:

The Joint Steering Group comprised of NERC leadership and OC, PC, CIPC, CCC, and SC officers concluded that integration of Technical Committee input in finalizing and disseminating effective and practical alerts is an important to realize reliability objectives. A framework proposal developed within the PC has been woven with a compatible NERC Staff proposal for further discussions among the JSG, with the objective of adoption by mid-year. Address timeliness, confidentiality, and practical technical input that enhances alerts dissemination, as evidenced by the GMD alert and the Facility Ratings guidance.

7. EA/DI Oversight:

The *EA pilot Phase II* recently began with some refinements designed to make the effort sustainable and consistent. Overall focus on making results/lessons readily available, permitting entities to focus on directly enhancing reliability, and avoid repeat events. PC and OC members are on the EAWG, but anxious to consider ways to expand expertise input in evaluating events/LLs. The complication centers around the extent to which compliance investigations/reviews are essential to developing sound technical lessons learned. This effort needs support to develop while avoiding CMEP focus/distraction – this has become one of the key issues to resolve.

8. Final Coda:

The resources within technical committees positions the industry and NERC in leadership roles on fundamental reliability issues [frequency response, Spare Equipment, GMD, Severe Impact Restoration, reliability assessments, HILF incident resilience, Coordinated Action Plan scenarios, long term reliability impacts of the resource mix, modeling/data coordination-validation, and as resource to validate Alerts/Events Analyses].

This is my final opportunity to present the BOT with a status report reflecting the work of the PC and its respective sub-groups. I feel privileged and honored to have been given the trust of NERC and afforded the chance to lead this group of highly competent and professional experts in multi-faceted areas of planning. I believe the stage is set for continued exceptional results from the PC arena - through the many aspects addressed during my tenure and the committed incoming leadership. Thank – you.

Cauley: "Best in Class" attention to deliverables, aligning resources for strategic benefit, attention to reliability issues, focus and deliverables among all the technical committees.

System Planning from a Canadian Perspective

Action Required

No action required

Status Report

1. Ric Cameron, NERC's representative in Canada, will present background and future perspectives on Canadian energy issues.
2. Context to the Canadian energy landscape and impacts on power system planning in will be reviewed.
3. Emerging Provincial and Federal political and technical issues will be discussed.

Eastern Interconnection Wide Area SynchroPhasor Angles Baselining Study

Action Required
No action required

Status Report
A presentation on the study to establish baselines for SynchroPhasor angles for the Eastern interconnection will be given at the meeting by Mahendra Patel.

Improved Processes and Procedures for Interconnection-wide Modeling

Action Required
None

Status Report

1. NERC Interconnections develop simulation models to support static and dynamic analysis.
2. The quality of models is inconsistent, and may not be able to support interconnection-wide challenges such as frequency response, under-frequency load-shedding, and geomagnetic disturbances.
3. Need to provide a forum for improvement, and technology transfer: process and procedures used to support models
4. NERC and regional entities will work together to lead the effort to develop measurably improved and consistent, high-quality simulation models.
5. Interface and coordination will occur through appropriate Planning Committee subgroups.

Consolidating Various Reliability Assessments, Measures, and Reports

Action Required
No action required

Status Report
Options for consolidation are under review and will be discussed at the September meeting.

ERCOT February 2, 2011 Grid Emergency Events

Action Required
No action required

Status Report
A presentation will be given at the meeting by Kent Saathoff, VP Operations and Planning, ERCOT ISO, on the events that occurred within the TRE region during the past winter storm.

Reliability Assessments Subcommittee (RAS) Report

Action Required

<u>Approve:</u>

1. Provide Risk Assessment by July 30, 2011

Background

1. 2011 Long Term Reliability Assessment Emerging Issues
    a. The RAS is requesting direction from PC members on which Emerging Issues in the Bulk Power System of North America the 2011 Long Term Reliability Assessment should focus attention on. The 2010 Emerging Issues are listed below:
        i. Impacts of Resource Mix Changes to System Stability and Frequency Response
        ii. Changing Resource Mix
        iii. Diminishing Frequency Response (in the Eastern Interconnection)
        iv. Transmission Operations with Vital Transmission Out-of-Service During Upgrades
        v. Uncertainty of Sustained Participation in Demand Response Programs
        vi. Consistent Modeling of Remote Resources

Status Report

1. The RAS met in April 2011 to discuss the aforementioned action items and upcoming reliability assessment documents.
2. *2011 Summer Reliability Assessment*
    a. A peer review was performed on the Regional self-assessments.
    b. Key findings were discussed and incorporated into the final report.
    c. A draft version of the *2011 Summer Reliability Assessment* was provided to the PC and OC on May 11th
3. The RAS is on schedule with all three-year work-plan items.

Load Forecasting Working Group (LFWG) Report

Action Required
No action required

Status Report

1. A meeting was held in Tampa, FL on February 24–25 at the FRCC offices.
2. The RAS directed the LFWG to investigate bandwidth development for the 2011 Long-Term Reliability Assessment. Specifically, new subregional breakdowns will increase the difficulty of establishing a solid historical dataset. The LFWG discussed two options:
    a. Decreasing the granularity to show interconnection-wide bandwidths
    b. Using data from 1993–present to develop bandwidths (versus the current historical dataset from 1980–present)

    After deliberations, the LFWG concluded that the two proposed options were unfavorable and producing less granular and less accurate bandwidths. Instead, the LFWG recommended a third option:

    c. Establish a data collection approach to gather data from the assessment areas (i.e., Regions, subregions, operating/planning areas).

    For this third option, assessment areas are able to provide their own bandwidths based on models developed during the planning process. By leveraging the work of the Resource Issues Subcommittee on probabilistic assessment, areas that would not otherwise have been able to develop their own forecast bandwidths, will soon be able to provide demand values on a probabilistic basis. This option will provide the greatest accuracy, sufficient granularity, and most importantly, be based on area-specific assumptions such as economic indices and government and utility policies. At its April meeting, the RAS endorsed this approach and recommended a trial period for the *2011 Long-Term Reliability Assessment.*
3. The LFWG is currently developing a whitepaper indentifying challenges in load forecasting during periods of increased uncertainty. The whitepaper is expected to be included in the *2011 Long-Term Reliability Assessment* as it relates to the demand forecast uncertainty inherent in the current environment.
4. Future activities include:
    a. Identify improvements for demand forecasting benchmarks;
    b. Evaluate energy forecasting techniques; and
    c. Monitor the economic trends to evaluate impacts on demand of any economic recovery.
5. The LFWG is on schedule with all three-year work plan items and no material changes are needed to the 2011 work plan.

Reliability Metrics Working Group (RMWG) Report

Action Required

1. Provide feedback on the 2011 Reliability Performance Analysis Report by June 30, 2011
2. Approve posting of the Integrated Reliability Index (IRI) concepts whitepaper for public comment and provide feedback by June 30, 2011
3. Approve the metric ALR1-5 System Voltage Performance voluntary data request

Background

1. The 2011 Reliability Performance Analysis Report can be found at http://www.nerc.com/docs/pc/rmwg/2011RMWG_Annual_Report.pdf.

   The 2011 annual report includes the status of 18 reliability metrics and their trending where applicable; 2008-2010 event Severity Risk Index (SRI) curves and its analysis. The report also introduces the Integrated Reliability Index (IRI) concepts.

2. The IRI is an integrated reliability index, comprised of three components, Event Driven Index (EDI), Standards/Statue Driven Index (SDI) and Condition Driven Index (CDI), as described below. The draft whitepaper can be found at http://www.nerc.com/docs/pc/rmwg/Integrated_Reliability_Index_WhitePaper_DRAFT.pdf.

   a. Event Driven Index (EDI): measures relative severity risk ranking of events based on event occurrence rate and their impact.

   b. Standard/Statute Driven Index (SDI): measures improvement in compliance with Reliability Standards. The violations included in SDI all have potential severe reliability impact and high violation risk factors.

   c. Condition Driven Index (CDI): focuses on a set of measurable system conditions to assess bulk power system reliability.

3. The voluntary data request letter to Transmission Owners (TOs) for reliability metric ALR1-5 System Voltage Performance can be found at http://www.nerc.com/docs/pc/rmwg/OC_PC_Letter_to_TOs_onALR1-5_final.pdf.

Status

1. RMWG held one face-to-face meeting on May 11-12 and eight conference calls from February to June 2011, and RMWG completed the following work plan activities:

   a. Drafted the 2011 Annual Report

   b. Completed 2008-2010 trending for SRI and published the result on the NERC website

   c. Revised the IRI whitepaper based on OC/PC's feedback and other stakeholder input received between March and May.

Integration of Variable Generation Task Force (IVGTF) Report

Action Required

1. Provide comments on the report *Potential Bulk System Reliability Impacts of Distributed Resources* (IVGTF1-8) to assessments@nerc.com by June 30, 2011.

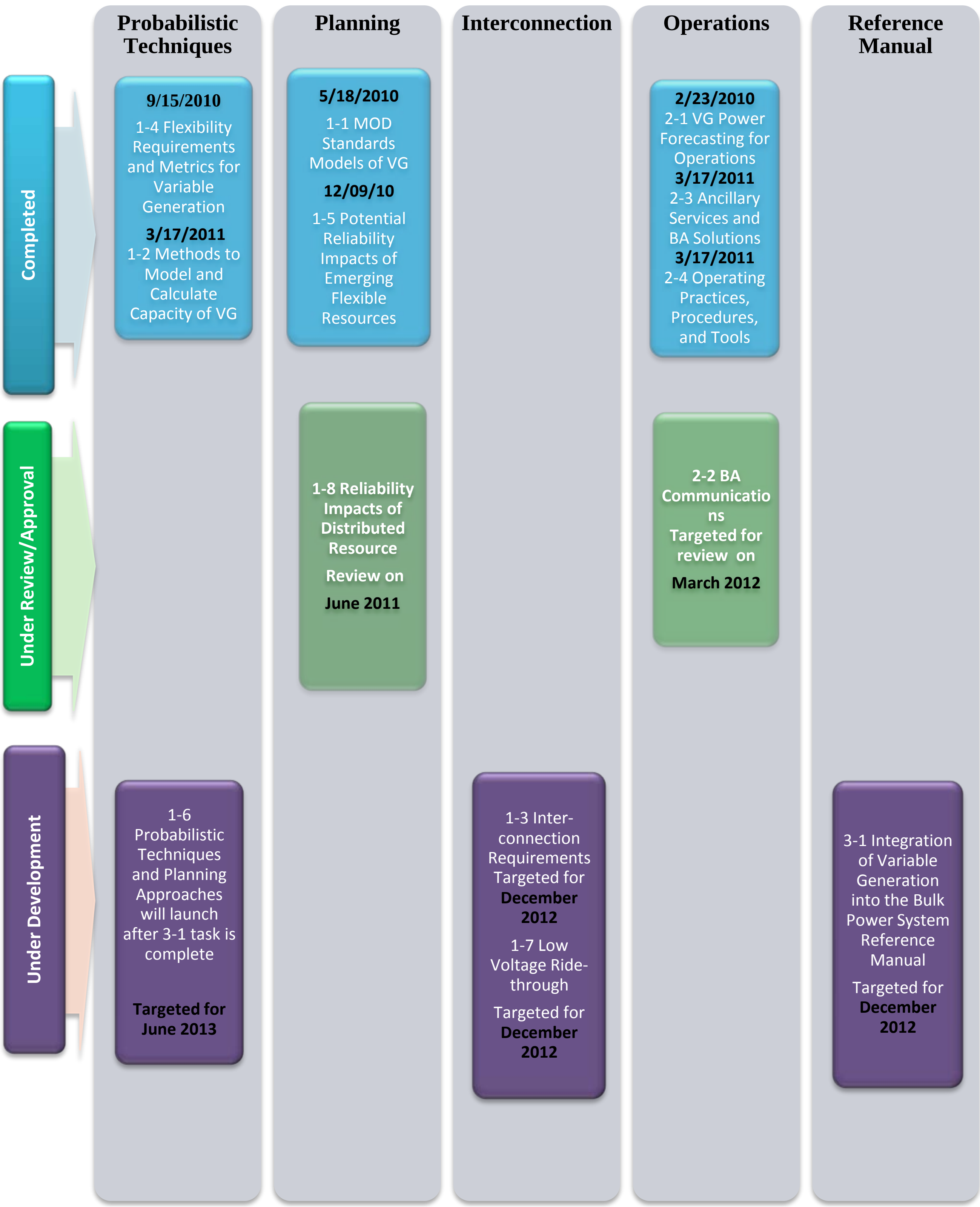
Background

1. The report Potential *Bulk System Reliability Impacts of Distributed Resources* led by Daniel Brooks, Manager of System Studies of Electric Power Research Institute (EPRI) with the help of fellow wind integration experts held consistent meetings to draft the IVGTF1-8 paper from March 2010 to January 2011. The completed draft is available at "*Potential Bulk System Reliability Impacts of Distributed Resources*".

Status Report

1. The IVGTF held a workshop in conjunction with the Utility Wind Integration Group (UWIG) on April 12 in Kansas City.
2. The workshop was followed by a leadership meeting with the chairs and team leaders providing an update to the remaining IVGTF report timeline (see updated work plan below).
    a. The IVGTF1-8 Potential Bulk System Reliability Impacts of Distributed Resources report considers distributed resources which are used for a variety of reasons: generation, storage and demand response. In the near future, as distributed resources on the distribution system is bi-directional in energy flow, the impact to reliability needs are to be understood and managed as the variability of generation resources such as wind and solar PV significantly can impact bulk system reliability, unless integrated carefully.

Completed and Future IVGTF reports for Planning and Operating Committees



[Link to *2009-2011 IVGTF Work Plan* Definitions of each Task Force](#)

Agenda Item 6.d
Planning Committee Meeting
June 7–8, 2011

Geomagnetic Disturbance (GMD) Task Force Report

Action Required
No action required

Status Report
1. NERC staff held an industry-wide workshop on April 19–20, 2011 at the JW Marriott in Atlanta, Georgia to discuss immediate prevention and mitigation steps that entities can take to counteract resiliency to their system in anticipation of geomagnetic disturbance events in the Northern Hemisphere.
2. A NERC Alert on Geomagnetic Disturbances (GMD) was developed, and released to the industry on May 10, 2011. The purpose of the advisory was to inform industry about currently available operating and planning options to fortify system resiliency and pre-posture systems for the potential impacts of geomagnetic disturbances.
   a. The following vetting of this alert has occurred:
      i. Announced at FERC's technical conference
      ii. Reviewed with the Geomagnetic Task Force Leadership
      iii. Discussed with the Planning and Operating Committee
      iv. Vetted with the Standing Committee Coordination Group (Chairs/Vice Chairs of all Standing Committees
      v. Vetted by industry experts as part of the Planning Committee's Alert review process, with comments from the PC ExCom as well
      vi. Review and comment from the Regional Managers
      vii. Comments obtained from the North American Transmission Forum (NATF)
      viii. GMD Workshop focused on the Alert. Workshop participants were informed of the Alert's contents and provided comments
      ix. NERC Management review
      x. Review by FERC
3. NERC Lessons Learned from the Alert development process
   a. Engage industry stakeholders at multiple points in the development process to ensure a quality product
   b. Be mindful of using language that implies Compliance related directives (unless intended)

c. Clearly outline roles, responsibilities, and timeline of the development process if allowable

4. The GMDTF will hold its next face-to-face meeting on June 9–10, 2011 at HydroOne's office in Toronto, Ontario.

Agenda Item 6.e
Planning Committee Meeting
June 7–8, 2011

Resource Issues Subcommittee (RIS) Report

Action Required
Review of comments on response matrix and final Generating Availability Data System Task Force (GADSTF) report.

Background
See GADSTF status report.

Status Report
None

Loss-of-Load Expectation (LOLEWG) Report

Action Required
No action required

Status Report

- The LOLEWG has not met since the last Planning Committee Meeting.
- The next meeting is scheduled for November 7-8 2011 at ERCOT offices with the Resource Issues Subcommittee. The *2011 Probabilistic Assessment Pilot* results will be discussed.
- The LOLEWG will provide subject-matter expertise to enhance the probabilistic assessments that will be included in future Long-Term Reliability Assessments.

GADS Task Force (GADSTF) Status Report

Action Required

1. Approve the report Generating Availability Data System: Mandatory Reporting of Conventional Generation Performance Data as modified from industry comments received as part of the 45-day public comment period for NERC's Board of Trustees consideration.

   The updated GADSTF Report with the revised recommendations is available at http://www.nerc.com/docs/pc/gadstf/Revised_Final_Draft_GADSTF_Recommendation_Report.pdf. The redlined version of the same report is available at http://www.nerc.com/docs/pc/gadstf/Revised_Redlined_Final_Draft_GADSTF_Recommendation_Report.pdf.

Background

1. In June 2010, the Planning Committee (PC) created the Generating Availability Data System Task Force (GADSTF) to review and recommend whether Generator Owners on the NERC Compliance Registry should report GADS data on a mandatory basis. The Resource Issues Subcommittee (RIS) approved this report and its recommendations for PC's consideration.[1]

   At its March 2011 meeting, the PC approved the posting of the report under Section 1600 Information and Data request for a 45-day public comment period, as called for in NERC's Rules of Procedures, Section 1600: *Requests for Data or Information*.[2] On May 5, 2011, the 45-day comment period ended. Nineteen comments were received and evaluated by the GADSTF and RIS leadership (http://www.nerc.com/docs/pc/gadstf/Section_1600_Report-Data_Request_Comments_and_Responses_05-23-11-cnv.pdf). To better reflect impacts on the bulk power system and accommodate comments received from the public posting, design data requirements and the capacity nameplate (MW) size for reporting were substantially reduced.

Status

1. Resource planning and generation experts were recruited to participate in the Generating Availability Data System Task Force (GADSTF). Four subgroups created the conclusions in the subgroup reports. One face-to-face meeting consolidated the final recommendations.
2. In October 2010, the GADSTF wrote a report summarizing their findings. The report was reviewed by the RIS at meetings and conference calls.
3. On January 26, 2011, the GADSTF report was sent to the RIS and PC for review and comments. On February 14, the RIS reviewed all comments from the RIS and PC.

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[1] This draft is posted at http://www.nerc.com/docs/pc/gadstf/GADSTF_Recommendation_Report_02-18-2011_FINAL.pdf

[2] http://www.nerc.com/files/NERC_Rules_of_Procedure_EFFECTIVE_20110412.pdf

4. On February 14, 2011, the RIS approved the GADSTF Report. On February 18, 2011, the GADSTF report was again sent to the PC.
5. On March 9, 2011, the PC approved posting for 45 days as part of the Section 1600 data request for comments.
6. On May 5, 2011, the 45-day comment period ended. Nineteen comments were received and evaluated by the GADSTF and RIS leadership, and modifications to the data request were made to response to the comments received.

Transmission Issues Subcommittee (TIS)

Actions Required

1. Approve the TIS Frequency Response Assignment Scope of Work **(Attachment 1)**
2. Approve TIS recommendation of the frequency response criteria:

   "Interconnection Criteria for Frequency Response Requirements"
3. Approve TIS collaboration with the System Protection and Control Subcommittee (SPCS) on their review of standards related to Special Protection Systems and Remedial Action Schemes.

Background

1. At the March 2011 Planning Committee (PC) meeting, the PC directed the TIS to develop a scope and implementation plan, including timing/deliverables, to address frequency response issues.
2. TIS Chairman Mark Byrd will present the initial TIS recommendation for frequency response contingency criteria. These criteria will be tested within the BAL-003 field trial.
3. The SPCS will be presenting a proposal for this work in their report to the PC. TIS believes they can provide subject matter expertise and system perspectives to support this effort.

Status Report

1. **Transmission Issues Subcommittee**
   a. The TIS has formed a task team to review MOD-010 through MOD-015 to prepare recommendations and measures for a SAR, in accordance with Task 5 of the Model Validation Task Force (MVTF) work plan, as assigned by the PC.
   b. The TIS will participate in the WECC and the NERC-EPRI modeling workshops in June. The TIS plans to hold 2 modeling workshops of its own on before the end of 2011.
   c. TIS provided comments on the recently posted draft definition of the Bulk Electric System (BES).
   d. As part of ongoing fault-induced, delayed voltage recovery (FIDVR) efforts, the TIS is participating in DOE-funded motor stalling research in conjunction with the Air-Conditioning Heating and Refrigeration Institute (AHRI). This research is identifying manufacturing-level solutions to air conditioning motor stalling which can be an important cause of FIDVR. Retrofit solutions are also being analyzed along with research in modeling. A status report on the results will be presented at a future PC meeting.

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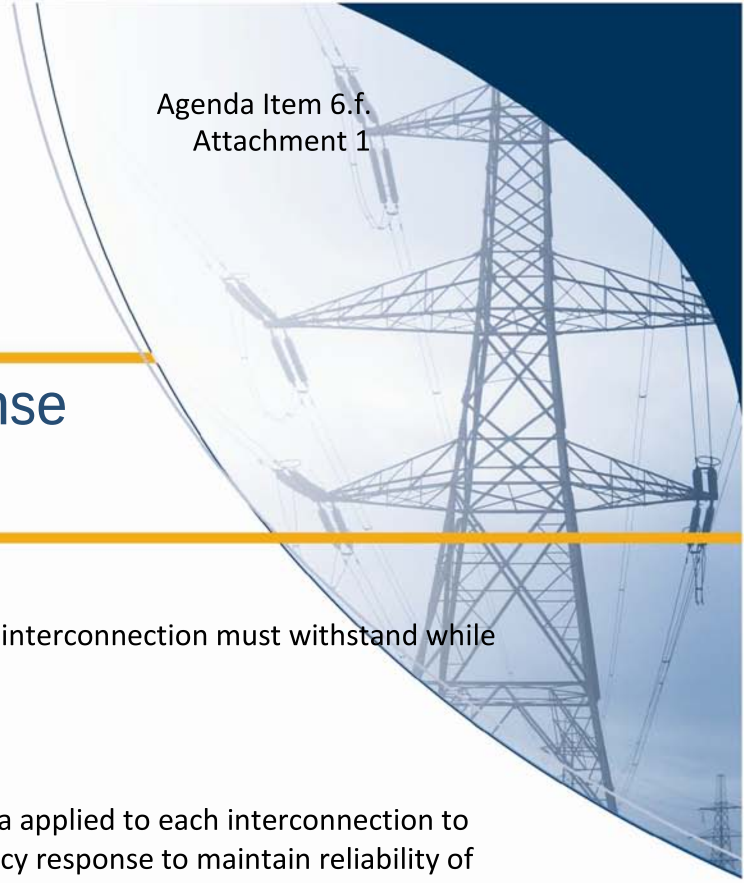

Agenda Item 6.f.
Attachment 1

DRAFT TIS Frequency Response Assignment Scope of Work

Purpose

Determine the maximum contingency levels each interconnection must withstand while maintaining acceptable frequency performance.

Activities

1. Analyze potential resource contingency criteria applied to each interconnection to determine an initial minimum level of frequency response to maintain reliability of the bulk power system. [March – April 2011]
2. Recommend the levels of frequency response for each interconnection for testing in the BAL-003 field trial. [June 2011]
3. Complete transient stability analysis for each interconnection to determine the maximum resource contingency size that can be sustained, while maintain acceptable frequency performance. The acceptable level must prevent actuation of the first-tier of regionally-approved UFLS trigger levels. [Western Interconnection and Texas Interconnection – Sept. 2011, Eastern Interconnection – after model is improved by ERAG]
4. Complete transient stability analysis for each interconnection to determine the maximum loss-of-load contingency that can be sustained while maintain acceptable frequency performance to prevent tripping of resources. [Western Interconnection and Texas Interconnection – by March 2012, Eastern Interconnection –after model is improved by ERAG]
5. Determine location limitations for the contingencies that might affect acceptable performance.
6. Examine potential frequency performance of other resources and classes of load influencing the contingency criteria in each interconnection.
7. For each interconnection, recommend the resource and loss-of-load contingency criteria

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Coordination

The TIS will coordinate this activity with and invite participation by:

- The Operating Committee
- The Resources Subcommittee (RS)
- The Frequency Response Working Group (FRWG)
- The Frequency Response Standard Drafting Team (FRRSDT)
- Other subject matter experts

Agenda Item 6.f.1
Planning Committee Meeting
June 7–8, 2011

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Model Validation Task Force (MVTF) Status Report

Action Required

1. Approve the posting of the draft procedures for modeling development and validation for a 30-day industry comment period.

Background

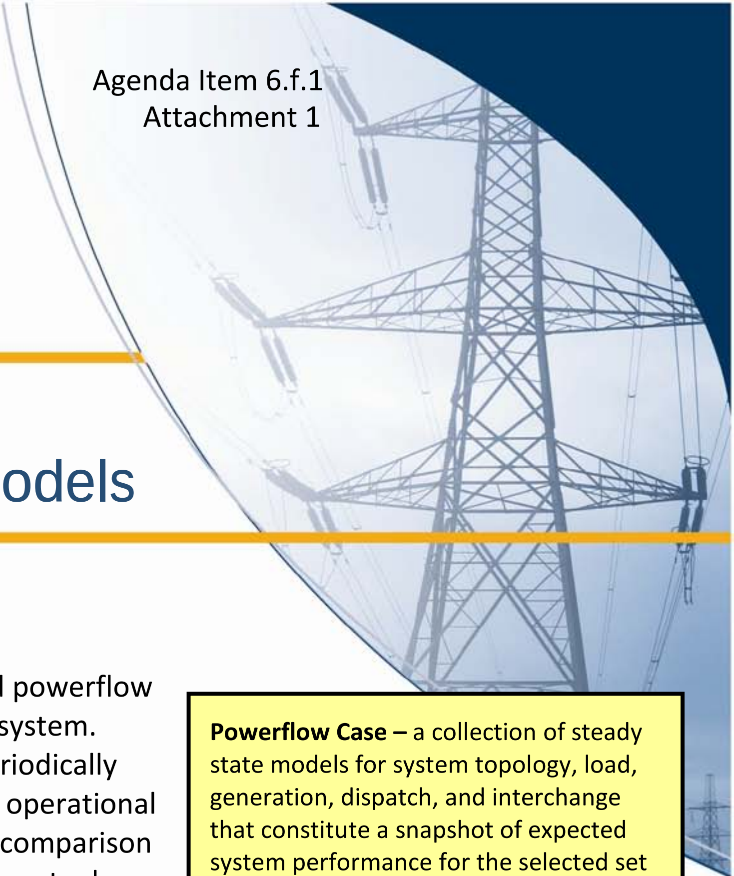
1. The MVTF draft procedures cover **(Attachment 1)**:
   - Assembling powerflow and dynamics models that reflect conditions at a specific time
   - Validation of the power system powerflow case
   - Validation of the power system dynamics model

   These procedures were drafted in accordance with tasks 1.2, 1.2, and 2.1 of the MVTF work plan. The MVTF is prepared to post these procedures for 30 days in accordance with task 1.4 of their work plan.

Status Report

1. **Modeling Validation Task Force**
   - The MVTF continues to execute its work plan.

Agenda Item 6.f.1
Attachment 1



Procedure for Validation of Power System Steady-State Models

Introduction

Steady-state models of the power system (often called powerflow cases) form the foundation of technical studies of the system. Because of this importance, these cases need to be periodically compared (benchmarked) to measured quantities and operational conditions and practices of the power system. Such a comparison validates that the power system case closely resembles actual operating conditions.

> **Powerflow Case –** a collection of steady state models for system topology, load, generation, dispatch, and interchange that constitute a snapshot of expected system performance for the selected set of operating conditions.

The primary means of validation is to compare and verify that the case matches the measured conditions on the power system at a specified point in time with reasonable accuracy. Additional comparisons are needed for validating some operational aspects of the model.

Only cases representing the currently existing ("as-built") system or near-term operating conditions can be directly validated. Cases that are intended to represent the system at a more distant time in the future should contain the same component representations as the validated current near-term model, unless there is a specific reason for the data to be different (i.e., a planned upgrade or system topology change), representing the cumulative planned changes to the system from the time of the validated near-term model through the timeframe intended to be represented by the case.

Aspects of the Model Validation Process

In general, a power flow system model is validated by comparing with observed conditions on the power system. This comparison is done by adjusting the generation dispatch and status of equipment in the model to match a particular point in time. The real and reactive system loads in the model also need to be adjusted to reasonably match state estimator load data and/or observed power flows at the same point in time.

If the case (with the adjustments described above) reasonably matches the measured quantities, the comparison validates the aspects of the models listed below. Some of these data represent physical characteristics of equipment, while others approximate operational practices.

- Transmission Network model
  - Line impedance, charging
  - Transformer impedance, tap position
  - Reactive shunt and series device size (for in-service elements) and operating status
- Generator
  - Reactive power output
  - Voltage schedules
- Load model
  - Total system load, bus load and load distribution
  - Real and reactive power
  - Power Factor for given time of day, season, and load level

Aspects of the case that represent projected quantities for future cases cannot be validated using this procedure. Such quantities include expected real and reactive power flows, expected load level, and projected generation dispatch.

Details of adjusting the power flow case to perform the comparison are described in Procedure 2.1, “Procedure for Assembly of a Power Flow and Dynamics Model for a Specific Time”.

Individual Data Verification

Some of the data in power flow models describe characteristics of the equipment that are not observable from a snapshot of power system data. Such data cannot be validated by the comparison of the power flow solution to system data and include:

- Transmission circuit and transformer ratings
- Generator real and reactive limits
  - Generator available reserves
- Generator mode (base load or frequency responsive, AGC or non-AGC)
- Voltage regulation procedure and target voltage profiles (generators, transformers with LTC, shunt devices)

These data require validation through field testing and/or knowledge regarding operational practices. (NERC standards MOD-024 and MOD-025, for testing generator real and reactive capability respectively, are currently under development.)

Procedure for Validation of Power System Dynamics Models

Introduction

Beyond the need for analyses of the steady-state behavior of the power system, it is crucial that the dynamics behavior of the system be analyzed as well. Power system dynamics cases form the foundation of those technical studies of the power system. Because of this importance, the simulated response of the power system obtained from these cases needs to be periodically compared to observed transient behavior of the power system. Such a comparison can only be practically performed for recorded system performance from system disturbances.

Preferably, these comparisons should be done for a number of system perturbations in order to provide a better calibration of the dynamics modeling and control parameters in the dynamics cases. Setting such parameters from a single test may provide good performance prediction for the test conditions, but the tested elements are constantly subjected to several different types of dynamic events.

> **Dynamics Case** – a collection of dynamics models used in conjunction with a powerflow model to perform a transient stability analysis of system performance.

Models are included for system elements such as, generation (including exciters, governors, power system stabilizers, current compensators, etc.), dynamic system control devices such as static var compensators (SVCs), fast-ac transmission system (FACTS) devices, DC terminal equipment and their controls, and dynamic loads such as motors and discharge lighting. Frequently, some system protection elements are also modeled such as system integrity protection schemes (SIPS), also known as special protection systems (SPS) or remedial action schemes (RAS). Also, for some studies, system protection for circuits, and relays for under-frequency or undervoltage load shedding are modeled.

This procedure provides a sequence of steps for validating a power system dynamics case. The primary means of validation is to verify that the case can simulate the dynamic response of the power system with reasonable accuracy when compared to an actual system dynamic event. A comparison of dynamic data recordings of a disturbance with the simulation of the disturbance is the principal method of verification. A variety of types of disturbances – generation loss, faults, and line trips – can test different aspects of the model, such as voltage response, frequency response, and oscillatory behavior.

Routine Tests

After assembly, any power system dynamics case should be subjected to some basic functional testing before it is used for any study:

- No-fault test (no-disturbance test) – all system states should remain constant for an indefinite period of time (test is typically run for 20 seconds).

- Ring down test – disturbance in which system returns to initial state after some time (typically 60 seconds).

These tests are intended to prove that the case does not have an inherent instability due to bad data or numerical anomalies in the dynamics solution.

Comparison with Dynamic Data Recordings

Initial Models and Information

In order to compare the response of an interconnection-wide dynamics case to dynamic data recordings, it is first necessary to construct a compatible power flow case of the power system conditions prior to the disturbance. (See Task 2.1, "Procedure for Assembly of a Power Flow and Dynamics Model for a Specific Time"). It is essential that the element identification in this powerflow case be aligned with the corresponding dynamics model data for each component in the dynamics case.

Next, a particular system disturbance is selected. Certain data regarding the disturbance is required for validating a system dynamics case, including a) sequence of events and b) the location and equivalent positive sequence impedance of any faults that occurred.

Using the combination of the aforementioned powerflow model and corresponding dynamics data, a simulation of a particular disturbance may be performed. Traces of the simulation results can be compared with dynamic data recordings, as shown below.

Quantities for Comparison (recorded Disturbance Monitoring Equipment (DME) data)

- Bus frequency
- Bus voltage and voltage angles
- Generator real and reactive output
- Line and transformer flows – real and reactive
- Static and dynamic VAR devices reactive output and voltage
- DC lines active power, terminal voltage and reactive power consumption

Aspects of Comparison

- Oscillations – frequency, damping, initial amplitude
- Initial and final state
- Minimum and maximum values
- Rates of change
- Comparison of simulation and recorded data plots for data described above

Model Data Collectively Validated By This Process (i.e., parameters that may cause mismatch between simulation results and measurements)
Comparisons between simulation results from the model and measured dynamic data provide an indication of the collective validity of a large set of component dynamics models (both their structures and their parameters), including in particular:

- Generator
  - Status of exciter
  - Status of PSS
  - Status of governor
  - Control parameters (gains, feedback time constants, etc.)
  - Machine characteristics (inertia, time constants)
- Load model
  - Real and reactive power under dynamic conditions
- Transmission Network model
  - Reactive shunt dynamics models (automatic shunt switching)

It is difficult to provide clear guidelines as to which dynamics model parameters have the largest impact on a mismatch between the simulated and recorded responses for a particular quantity in a given disturbance. In many cases, a mismatch at a particular location identifies a need to individually validate the dynamics models of the system components in that vicinity. Availability of more data from multiple locations makes it possible to narrow down the location of the problematic component models.

Procedure for Assembly of a Powerflow and Dynamics Cases for a Specific Time

Introduction

Validation of powerflow and dynamics cases requires the assembly of a powerflow case that represents system conditions at a specific time. Such case assembly is also critical in performing forensic analysis of disturbances on the power system.

This procedure provides a sequence of steps for building a dynamics-compatible steady-state case that represents system conditions at a specific time. The procedure is based on redispatching an existing dynamics-compatible powerflow case to match the desired system conditions. An alternate approach is the capturing of a state-estimator powerflow case for a specific time, and then adding dynamics data. That process is very useful for event replication, but does not allow validation of the off-line study cases or their modeling elements.

Powerflow Case Assembly

First, a suitable powerflow case is selected. If system dynamics models are to be validated, the powerflow case must be dynamic compatible. Next, a snapshot of power system conditions for a specific time needs to be assembled.

Transfer Input Data to Case

The following items from the snapshot data are transferred directly into the steady-state powerflow case (state estimators may be a suitable source for this data):

- Generators
  - Real power output
  - Reactive power output or voltage setting
  - Control mode (voltage control, power factor control)
  - Voltage regulation point (local or remote, if on voltage control)
  - Status
- Loads
  - Measured real power at available granularity
  - Measured reactive power
- Transmission Network
  - Network topology
  - Device statuses

- Transmission lines
- Breakers (may result in split buses)
- Reactive shunt elements (Capacitor, Reactor)
- Reactive series elements (Capacitor, Reactor)

- Fixed-tap transformer tap positions
- ULTC transformers – tap position or voltage setting
- Phase-shifting transformers – angle position or MW setting
- Static VAR systems and fast-switched shunt devices – reactive output or voltage setting
- DC lines – active power flow
- Other devices present in system model

- Wide-Area Control
  - Area interchange totals

After this data is inserted into the case, a powerflow solution is performed. In order to obtain convergence, it may be necessary to temporarily relax some constraints (such as VAR limits) and/or solution parameters, particularly if the system conditions being modeled are significantly different from the conditions contained in the original powerflow case. A subsequent solution with more stringent constraints and tolerances should then be successful. Key quantities in the solved powerflow case are then compared against observed system conditions and data in the system snapshot. Exact matches for flows and voltages should not be expected. However, it is desired to replicate the voltages and to the greatest extent possible. Correlations of better than 85% are desirable for real and reactive flows, and voltage levels should be within ±0.03 per unit.

Quantities for Comparison

- Real power output of system slack and area slack machines
- Generator reactive output and voltage
- Line and transformer flows – real and reactive
- Interface flows – real and reactive
- ULTC transformer tap position and voltage
- Phase-shifting transformer angle position and MW and Mvar flows
- Station voltages
- Station voltage angles when PMU data are available for the conditions being modeled
- Static VAR devices reactive output and voltage
- DC lines terminal voltage, MW flows, and reactive power consumption

If the comparison is unsatisfactory, there are two basic causes. First, the measured power system data may have significant errors. Second, there are a number of data in the power flow model that can cause the comparison to fail:

Powerflow Case Parameters That May Cause Mismatch

- Incorrect transmission network model values
  - Line impedance, charging
  - Transformer impedance, fixed tap position
  - Reactive shunt devices size
  - Reactive series devices size
- Incorrectly split across buses
- Load distribution on each of the busses across the system may differ significantly from the actual system conditions.
- The power factors on each bus in the original case may differ significantly from the actual power factors for the system conditions.
- Spurious (non-existent) transmission elements in the source case

Engineering judgment and knowledge is used to identify faulty powerflow modeling parameters. After identifying and correcting such errors in the powerflow model data, the powerflow is resolved and the comparison process is iterated. Detailed examination of these parameters must be performed during each iteration, and several bus-by-bus adjustments to load and power factor may be required to obtain a good correlation to the observed system voltages and flows.

When the comparison is deemed satisfactory, the resulting powerflow solution is an acceptable representation of the system conditions at the selected time.

After the powerflow model is assembled, it can be readily used to initialize a dynamics simulation, since the dynamics model data for each of the components will correspond with the powerflow case.

System Protection and Control Subcommittee (SPCS) Report

Action Required

1. Approve for posting as final, the *Transmission System Phase Backup Protection* reliability guideline.

2. Approve development of a report, to be developed with the Transmission Issues Subcommittee (TIS), assessing Special Protection System (SPS) related standards and regional practices concerning SPS application.

Background

1. **Transmission System Phase Backup Protection Reliability Guideline**
   In December 2010 the PC approved posting the *Transmission System Phase Backup Protection* reliability guideline for industry comment. The SPCS has responded to all comments received during the 45-day comment period and has revised the document based on these comments. Clean and redline versions of the revised report can be found at CLEAN-Reliability Guideline: Transmission System Phase Backup Protection and REDLINE - Reliability Guideline: Transmission System Phase Backup Protection respectively, as well as the comment form with SPCS responses to each comment, Comment Form for Reliability Guideline: Transmission System Phase Backup Protection. The revisions to the document clarify concepts and examples used to support the conclusions and recommendations, but do not alter the conclusions and recommendations. The SPCS requests approval to post this reliability guideline as final.

   This reliability guideline was developed in response to a number of significant system disturbance reports since the 2003 Northeast Blackout that have recommended evaluating specific applications of adding backup and/or redundant protection The most significant of these is the FRCC report from the February 26, 2008 system disturbance which recommends that "NERC should assign the System Protection and Control Task Force to produce a technical paper describing the issue and application of backup protection for autotransformers."

2. **Assessment of Special Protection System Standards and Regional Practices**
   The SPCS proposes to conduct an assessment of the SPS-related PRC standards and definition of SPS, conduct an assessment of existing regional practices summarizing commonality and differences, and document its findings in a report to the Planning Committee that can serve as a reference document for a standard drafting team that ultimately will be assigned to review these standards. If deemed appropriate, the report could be used to support a Compliance Application Notice (CAN) to address part of this issue until a revised definition and standard(s) are developed. The SPCS further proposes this activity should be a joint effort with TIS. The SPCS notes that an assessment of the existing SPS-related PRC standards already is on the SPCS work plan. The SPCS proposes to

expand the scope of this assessment and collaborate with TIS to address concerns related to regional practices raised by the ERO-RAPA Group. The SPCS requests approval of the attached proposal **(ATTACHMENT 1 – Assessment of Special Protection System Standards and Regional Practices).**

Status Report

1. SPCS/TIS Document on Response of Protective Relays to Power Swings

a. Assignment: Develop a white paper, with support from TIS, on the subject of the response of protective relays to power swings. This paper will support development of a standard on this subject, as directed in FERC Order No. 733.

b. Status: The SPCS and TIS team supporting this effort have identified a number of methods that may be useful for identifying transmission lines that are subject to tripping during stable power swings. Power system simulations are being utilized to screen these methods. The SPCS and TIS team continue to meet by conference call and during SPCS meetings and is working to complete the document by September 2011. Action requested of the PC will depend on whether the final document is classified as a reliability guideline or a technical reference document. The SPCS will make an appropriate recommendation based on the report content.

2. Assessment of Breaker Failure Protection Design Issues

a. Assignment: The SPCS is reviewing breaker failure design issues relative to an October 10, 2010 Lesson Learned on this subject. The SPCS will develop guidance on this subject as deemed appropriate.

b. Status: An SPCS sub-team has reviewed the Lesson Learned and relevant IEEE guides and concluded that IEEE guidance on this subject is appropriate. Based on prioritization of SPCS work, the schedule for completion of this document has been extended to September 2011.

3. Common Misoperations Reporting Template

a. Assignment: The SPCS is supporting ERO-RAPA Group development of a common template to be used in all regions for misoperation reporting.

b. Status: The SPCS continues to provide technical support as needed responding to industry questions on the reporting template.

Meeting Schedule

The SPCS has scheduled the following meetings in 2011.

June 28–30	San Francisco, CA (PG&E hosted)	Tues Full Day Wed Full Day Thurs Half Day
September 28–30	Minneapolis, MN (Xcel hosted)	Tues Full Day Wed Full Day Thurs Half Day
November 8–10	Location TBD	Tues Full Day Wed Full Day Thurs Half Day

Assessment of Special Protection System Standards and Regional Practices

Proposal

The System Protection and Control Subcommittee (SPCS) proposes to conduct an assessment of the SPS-related PRC standards and definition of SPS, conduct an assessment of existing regional practices summarizing commonality and differences, and to document its findings in a report to the Planning Committee (PC) that can serve as a reference document for a standard drafting team that ultimately will be assigned to review these standards. If deemed appropriate, the report could be used to support a Compliance Application Notice (CAN) to address part of this issue until a revised definition and standard(s) are developed. The SPCS further proposes this activity should be a joint effort with the Transmission Issues Subcommittee (TIS).

Rationale

- The SPCS scope calls for providing subject matter expertise for NERC Standards related to protection systems and controls, and the SPCS work plan includes an assignment to review all existing PRC-series Reliability Standards, to advise the PC of its assessment, and to develop Standards Authorization Requests, as appropriate, to address any perceived deficiencies.
- The SPCS has reviewed all PRC standards except the group of SPS standards. The SPCS had started assessment of these standards, but the assessment was deferred due to other priority work such as the Power Plant and Transmission System Protection Coordination technical reference document.
- The SPCS has reviewed its work plan and determined that this is the next logical project for the SPCS. Work on the Transmission System Phase Backup Protection reliability guideline is wrapping up at this time and the SPCS can make the SPS review one of two priority activities for this year (the other is the document addressing operation of protection systems in response to power swings).
- The SPCS believes that a thorough review of SPS-related PRC standards would benefit from the expertise of Transmission System Subcommittee (TIS) and the SPCS recommends a joint SPCS/TIS effort coordinated by the SPCS. This proposal has been reviewed with and is supported by TIS.
- The SPCS proposes to conduct an assessment of the standards and definition of SPS, and conduct an assessment of existing regional practices summarizing commonality and differences among the various regional practices.
- The SPCS believes that differences among regional practices must be resolved through a formal process; a consensus opinion of what constitutes an SPCS would lack standing unless it is vetted through a stakeholder process. The SPCS proposes to document its findings in a report that can serve as a reference document for a standard drafting team that ultimately will be assigned to review these standards. If deemed appropriate, the report could be used to support a CAN to address part of this issue until a revised standard(s) is developed.

- The scope of work for such a review is significant and direction should come through the NERC Planning Committee as the body to which SPCS and TIS report.
- The SPCS believes that an appropriate time frame for completing this report would be to submit a draft to the Planning Committee at its March 2012 meeting. The SPCS and TIS believe this schedule is appropriate to support a thorough review.

Agenda Item 6.h
Planning Committee Meeting
June 7–8, 2011

Data Coordination Subcommittee (DCS) Report

Action Required

No action required

Status Report

1. Had a conference call/Webex on May 4, 2011

2. First goal is to finalize the Whitepaper
   - Incorporate the comments received and the status of items in the Whitepaper that will be covered by others

3. Model validation effort status
   - Reviewed the status of the Model Validation Working Group
   - Several validation initiatives are mentioned in the Whitepaper

4. TIS status/development of SARs for MOD-10 through MOD-015
   - Reviewed the status of the SAR development by TIS

5. GADS status
   - Reviewed the status of the GADS conversion to mandatory reporting

6. TADS/DADS status
   - Reviewed the status of TADS and DADS and possible coordination with other data gathering efforts

7. Any new data requests from DCWG, RAS, RIS, TIS
   - Discussed the procedure for using the NERC Rules of Procedure to initiate a data request
   - No new formal data requests have been initiated

8. Database linking/NERC Common ID for BES Equipment – Do we move forward?
   - Discussed this possible data coordination effort
   - The group will still consider this but further discussion is required to start any work
   - Some felt this may be more trouble than it's worth

9. What do future FERC-715, EIA-411, EIA-860 requests look like
   - Looked at future plans

Transmission Availability Data System Working Group (TADSWG)
Status Report

Action Required

1. Approve TADSWG to work on a draft request for comments (under Rules of Procedure 1600) on reporting 100-199kV outages in webTADS beginning January 1, 2014. See background below.

Background

1. **100-199kV TADS Data Request Options**

   TADSWG has evaluated possible options for incorporating 100-199kV data request into TADS due to:

   - the EIA's stated intent to collect such data through their proposed 2014 Form EIA-411 Schedule 7 (would require reporting of 2013 data); and
   - the anticipated revision to the Bulk Electric System (BES) definition in response to FERC Order 743.

   Five options for reporting the 100-199kV outage data were discussed at length at the May TADSWG meeting, including:

   1. Summary/aggregate reporting.
   2. TADS current format.
   3. Revised TADS line section format.
   4. Revised Retro-TADS format that would also change the current >200kV data collection.
   5. Delayed decision based on waiting till the BES definition is completed.

   The preferred option that the TADSWG wishes to seek comments on is summarized below:

   > Option 2: Collect new 100-199kV outage data from each TO using the existing TADS format. TOs would enter information for each individual outage and event, as well as inventory, for this additional voltage class in webTADS beginning January 1, 2014.

   The TADSWG will consider several issues in the development of the 1600 request including:

   a. Which Elements to include, all 100-199kV (no exceptions), or based on BES definition.
   b. Which outage types to collect, Automatic, Operational, Planned.
   c. Which data fields to collect.
   d. Revisions to forms and definitions for 100-199kV outage reporting.

The TADSWG will follow a schedule defined by the PC approved TADS Major Change process for modifying TADS. A one year delay to the proposed EIA mandatory reporting of 2013 outages would be required. Instead mandatory 100-199kV outage data collection would begin 1/1/2014, and Schedule 7 report submitted to EIA by July 15, 2015.

A survey was conducted amongst the TO's in the TADSWG and a summary of the survey and its conclusions will be presented.

Status

This report will be presented by the TADSWG Chair Michael Pakeltis

1. **2010 TADS Statistical Facts Report**: The annual TADS automatic and non-automatic statistical report is on schedule for presentation to Planning Committee for approval at the September 2011 meeting.
2. **Supplemental Analysis**: TADSWG has vetted the draft RMWG report section that pertains to TADS; TADSWG supports future cross-functional team analysis as noted in the RMWG draft report. TADSWG supplemental analysis will be incorporated into and guided by that cross-functional team.
3. **2010 TADS Data Reporting to EIA:** The TADS data submittals for the 2010 calendar year will be provided by NERC to EIA on or before the July 15, 2011 deadline in accordance with EIA-411 Schedule 7. A process to prepare the EIA data was successfully tested by NERC. Special request for EIA specific 100-199kV DC Circuit data have been released to the affected utilities.
4. **TADS Data Validation Process Change:** Since the March PC meeting, the questionnaire has been updated but additional discussions are needed to define how it might be implemented on a regional basis. TADS Secretary will coordinate discussions of this issue with Regional management through the ERO-RAPA group.

Demand Response Data Task Force (DRDTF) Status Report

Action Required
No action required

Status Report
1. New Chair of the Demand Response Data Task Force:

   Sharon K. Bauer
   Director - Demand Response Programs
   Efficiency & Innovative Technology
   Corporate Development & Improvement
   Progress Energy Florida
   Office: 407-942-9777
   Cell Phone: 407-474-7609

2. NERC along with Open Access Technology International, Inc. (OATI) continue to develop webDADS for mandatory data reporting required in DADS Phase II. This is part of NERC's unified platform approach, in which TADS, GADS, and DADS will all the same system of reporting in order to efficiently and effectively relate information between the systems.

   The Functional Specification has been issued and approved by NERC. The official announcement to stakeholders will be sent out in June 2011. The following dates will be a part of the announcement:

   a. webDADS beta version to be ready June-July
   b. NERC Acceptance Testing for OATI system 8/4/2011
   c. software training session during the middle/late August Time frame
   d. webDADS Registration 9/1/2011
   e. The first reporting season is planned for April-October of this year with the first set of data due December 15, 2011
   f. publically available data/report in the February to March 2012 timeframe

3. June 2, 2011 was DRDTF's last phone meeting. Discussed future plans and dates of DADS and confirmed metric calculation.

4. Future actions include:
   a. Continue with webDADS development, training, data collection and analysis
   b. Coordinate with Regional Entities to review responsibilities.

5. The work plan activities are on schedule.

Spare Equipment Database Task Force (SEDTF) Status Report

Action Required

1. Provide feedback on SEDTF interim whitepaper “Spare Equipment Database” to Ron Niebo, ron.niebo@nerc.net by June 30, 2011. The whitepaper is available at: http://www.nerc.com/docs/pc/sedtf/DRAFT_SEDTF_Interim_Whitepaper_June_2011.pdf.

Background

1. The Spare Equipment Database Task Force (SEDTF) was initiated by the Planning Committee (PC) as part of the ESCC’s *Critical Infrastructure Protection Roadmap* and is a function of NERC’s Joint Steering Group. The SED function is noted as a Proposal for Action in the *High-Impact, Low-Frequency* (HILF) report of June 2010 (page 14), and the *National Infrastructure Advisory Council - November 15, 2010* report to the resident of the United States title “*A Framework for Establishing Critical Infrastructure Resilience Goals,*” (page 10). The Task Force’s scope was approved at the September 2010 PC meeting and its twelve milestones and activities are to be completed by the end of 2011.

   SEDTF chair, Dale Burmester, will present an overview of the Task Force’s activities. SEDTF is making good progress and the initial draft of its summary Whitepaper is ready for review. Four of the major conclusion/recommendations contained in the INTERIM white paper include:

   a. **Participation:** The Spare Equipment Database (SED) will be voluntary and all NERC registered Transmission Owners (TOs) and Generator Owners (GOs), whether or not they have spare equipment available, will be asked to participate.

   b. **Content:** The SED will initially focus on long-lead time transformers: transmission auto-transformers (auto) and generation step-up transformers (GSU). The database will include transmission transformer spares with a low side ratting of 100 kV and above and the top nameplate rating is 100 MVA or higher (total equivalent 3-phase rating). Generation step-up transformer (GSU) spares will have a high side voltage of 100 kV or higher and the top nameplate rating is 75 MVA or higher (total equivalent 3-phase rating).

   c. **Timeline:** SED will be an online program available to registered users (TOs and GOs) on a 24x7 basis beginning in 2012. Its operation will be managed by NERC staff and coordinated with a contract web-based vendor.

   d. **Confidentiality:** SED will be operated as a secure database equipped with procedures and safeguards to assure data confidentiality. Participants will be required to sign a confidentiality agreement.

Status

SEDTF is scheduling its activities such that a ‘for approval’ Whitepaper may be presented to the PC at the September 13-14 meeting. SEDTF will soon initiate activities to assist NERC in preparing the SED specification for use in selecting a support vendor. The intent is that beginning in January 2012, industry TOs and GOs will voluntarily report their spares. During this ‘pilot’ year of 2012, the SEDTF anticipates it will assess the voluntary program quarterly and provide information to the NERC PC to determine if additional measures are required to increase participation.

Data Coordination Working Group (DCWG) Status Report

Action Required

No action required

Status Report

1. The DCWG has developed three functional requirement options for a common database portal for that would collect LTRA and Seasonal Assessment data:
   a. OPTION A: Regions would upload and submit complete data sets on an annual basis; the database portal would automatically flag erroneous entries based on last year's data.
   b. OPTION B: NERC would upload existing data to the portal and Regions would provide annual updates (i.e. adding/subtracting future or retired plants).
   c. A combination of OPTION A and OPTION B.

   NERC Regions will consider these options and provide feedback prior to, and during the next DCWG meeting in fall, 2011. Additional features would enhance NERC's ability to collect Regional data in a timely manner and ensure that the data obtained is the most current prior to publishing assessments. Further, the common assessment data will allow data submitted by the Regions to be processed and analyze in significantly less time.

2. Consideration will be given to the possibility of using certain TADS (transmission-specific) data to complete the LTRA Schedule 5. In the interim, cross-checks will be performed, along with an explanation of any discrepancies between the two data sources (LTRA and TADS).

3. The LTRA schedule for data submissions was reviewed. Additional enhancements were discussed regarding the 2011 LTRA data form and future consideration will include modeling of multiple units at a given plant location (especially wind and hydro) as an "Individual Unit" (i.e. 10 wind turbines = 1 individual unit).

4. A common approach is needed to investigate how transmission data is collected for each assessment area. The task force agreed that existing and projected transmission lines should be reported based solely on area location. Additionally, transmission lines should be segmented if projects are located across national boundaries, area boundaries, or line characteristics change (i.e., voltage changes, current changes). DCWG will work with EIA to develop specific guidelines prior to issuing the next LTRA form.

5. The DCWG continues to work with EIA to support future data needs and resolve data collection issues for the new version of EIA Form EIA-411. For example, EIA anticipates mandating collection of generator availability, as well as transmission availability data to include 100 kV by 2013. In addition, EIA expects NERC to work closely with them on changes

to forms so EIA's IT can make appropriate changes to their. EIA has indicated that they will not be implementing a two-year cycle for the redevelopment of all EIA forms. The next Form EIA-411 will be implemented in 2014.

6. The three-year work plan activities for the DCWG are on schedule.

7. An MOU between NERC and EIA is being developed to address confidentiality issues related to EIA sharing preliminary 860 data with NERC.

8. DCWG conducted a training session for all members to clarify the instructions for data collection forms.

9. The next DCWG Meeting is tentatively scheduled for October 19–20, 2011 (Wednesday and Thursday) at the NERC office in Washington, DC. EIA will provide NERC with data analysis they have conducted to assess the interdependency of gas and electric infrastructure supporting NERC's current scenario analysis.

Smart Grid Task Force (SGTF) Report

Action Required
No action required

Status Report

1. NERC Staff, with support from the Planning Committee (PC) and Smart Grid Leadership team, submitted comments in response to the January 31, 2011 FERC Technical Conference regarding Smart Grid Interoperability Standards on April 8, 2011.[1] FERC called for industry comment,[2] for which NERC provided answers the following questions:
   a. How does the NIST process assure that a standard has undergone sufficient review of interoperability and cyber security and is ready for consideration by regulators?
   b. Is it appropriate for reliability and implementation issues to be reviewed by a separate panel, as some panelists commented at the technical conference, composed of utility representatives and NERC?
   c. Whether the criteria for the Commission's evaluation should differ for interoperability and functionality, and the extent to which cyber security is an element of each.
   d. NERC's full response has been posted.[3] .

2. The next face-to-face meeting is scheduled for June 23, 2011 at NERC's Atlanta, GA offices.

3. Future activities include:
   a. Review modeling requirements, planning and operating tools, and analysis techniques to measure and understand system performance while accommodating smart grid integration (2012)
   b. Assess reliability considerations that need to be addressed with the integration of large amounts of smart grid devices and systems on the distribution system (2012)
   c. Form liaisons with U.S. and Canadian standards-setting groups to ensure coordinated and harmonized standards to support reliability (on-going)
   d. Further refine defense-in-depth and risk assessment approaches to manage cyber and physical security with smart grid integration (2012)

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[1] http://www.ferc.gov/EventCalendar/EventDetails.aspx?ID=5571&CalType=&CalendarID=116&Date=01/31/2011&View=Listview
[2] http://www.ferc.gov/EventCalendar/Files/20110228084004-supplemental-notice.pdf
[3] http://www.nerc.com/files/Final_NERC%20Comments%20_NIST%20Smart%20Grid%20Inter_stds.pdf

Events Analysis Working Group (EAWG) Status Report

Action Required

None

Status Report

1. NERC and the EAWG have conducted two industry webinars April 14 and April 26, 2011.
2. The EAWG is currently drafting responses from the Q&A from the recently held webinars and will post on NERC's web site.
3. Version 2 of the ERO Event Analysis Process document was posted on the NERC web site on May 2, 2011 for comment (http://www.nerc.com/page.php?cid=5|365).
4. Phase 2 of the field trial began on May 2, 2011.
5. Three "Lessons Learned" from EAWG were posed on May 10, 2011.
6. Jacquie Smith (EAWG Chair) will provide a status presentation including field trial metrics at the Toronto Meeting.

The working group continues to meet on a weekly basis to capture opportunities for improving the process document, as well as the execution of the process.