

North American Electric Reliability Council

Princeton Forrestal Village, 116-390 Village Boulevard, Princeton, New Jersey 08540-5731

PERFORMANCE SUBCOMMITTEE MEETING

Thursday, April 24, 1997 — 1 p.m.-5 p.m.

Friday, April 25, 1997 — 8 a.m.-12 noon

The Coeur d'Alene
Coeur d'Alene, Idaho

AGENDA

1. Administrative Matters

- a. Introductions
- b. Arrangements — Colin L. Wright
- c. Approval of Minutes of January 23-24, 1997 Meeting — Colin L. Wright
- d. Approval of Agenda
- e. Organization, Roster, and Contacts List*
 - i) Sector representation on Subcommittee
- f. Control Area Diagrams & Acronyms*

2. Operating Committee — William C. Phillips, Colin L. Wright

- a. Report on April 9 meeting of OC Subcommittee chairmen with IOSWG — Albert M. DiCaprio
- b. Update on NERC "Transmission Market & Security Initiatives" efforts — Colin L. Wright

3. Compliance Issues

- a. Area Interchange Error — Albert M. DiCaprio
 - i) January 31, 1997-February 6, 1997 Survey*

4. Control Criteria Task Force — Alan R. ONeal

- a. Status of CPS/DCS Implementation
- b. Frequency Task Force report — Howard Illian, Don McInnis
- c. Inadvertent Task Force — Bart McManus
- d. Reserves Task Force — Wayne Smith
- e. Operator Interface Task Force — Edward Riley
- f. Schedule of completion of new Standards development

5. Policy 1

- a. Policy 1 rewrite – Action Plan
 - i) Tying together the Task Force efforts/drafts
 - ii) IOSWG Implementation changes
 - iii) Assignments

6. Inadvertent Interchange

- a. Inadvertent balancing problems
- b. Off-Peak Days for 1998, 1999, and 2000*
- c. Interconnection Reports — Eastern Interconnection rep, Dennis B. Hogan, Grant Griffith
- d. Monthly AIE Surveys

7. Update on Video Tape Tutorial for CPS and DCS

8. Control Performance — William C. Phillips

9. Time Error

- a. Eastern Interconnection — Albert M. DiCaprio
- b. Western Interconnection — Grant E. Griffith
- c. ERCOT Interconnection — Dennis B. Hogan

10. Frequency Response

- a. Eastern
- b. Western
- c. Review of events (plots)
 - i) Should Eastern reportable limit be raised to 2,000 MW? — William C. Phillips

11. Roundtable Discussion

- a. Summer 1996
- b. Winter 1996/97

12. Dates and Locations of Future Meetings*

- a. Re-selection of locations for October 1997 and beyond

NERC PERFORMANCE SUBCOMMITTEE
ORGANIZATION AND ASSIGNMENTS

Chairman: Al DiCaprio

Vice Chairman (ERCOT): Tom Brown

Vice Chairman (WSCC): Ed Riley

<p><u>ECAR</u></p> <p>Doug Hils Open Control Criteria TF</p>	<p><u>ERCOT</u></p> <p>Dennis Hogan Open Control Criteria TF</p>	<p><u>MAAC</u></p> <p>Al DiCaprio Open Control Criteria TF</p>																								
<p><u>MAIN</u></p> <p>Terry Bilke Open Control Criteria TF</p>	<p><u>MAPP</u></p> <p>Alan Oneal Open Control Criteria TF-<i>Ch</i></p>	<p><u>NPCC</u></p> <p>Mike Potishnak Open Control Criteria TF</p>																								
<p><u>SERC</u></p> <p>Gary Rudder Open Control Criteria TF</p>	<p><u>SPP</u></p> <p>Bill Phillips Open Control Criteria TF</p>	<p><u>WSCC/AZ-NM</u></p> <p>Phil Clark Open Control Criteria TF</p>																								
<p><u>WSCC/NWPP</u></p> <p>Grant Griffith Open Control Criteria TF</p>	<p><u>WSCC/CA-SNV</u></p> <p>Ed Riley Open Control Criteria TF</p>	<p><u>WSCC/RMPP</u></p> <p>Mirek Horenovsky Open Control Criteria TF</p>																								
<p>Control Criteria Task Force</p> <p><u>Alan Oneal</u> All PS representatives</p>	<p>Inadvertent Task Force</p> <p><u>Bart McManus</u> Howard Illian Dennis Hogan Gary Rudder Doug Hils Wayne Smith Don McInnis</p>	<p>Frequency Task Force</p> <p><u>Howard Illian</u> Charles Sanders Mirek Horenovsky Dennis Hogan</p>																								
<p>Reserves Task Force</p> <p><u>Wayne Smith</u> Alan Oneal Mirek Horenovsky Don McInnis Grant Griffith</p>	<p>Operator Interface Task Force</p> <p><u>Ed Riley</u> Mike Potishnak Charles Sanders Howard Illian Phil Clark</p>																									
<p>Survey Assignments</p> <table style="width: 100%; border: none;"> <tr> <td style="width: 33%;">Control Performance Criteria Survey</td> <td style="width: 33%;">Bill Phillips</td> <td style="width: 33%;"></td> </tr> <tr> <td>Area Interchange Error Surveys (East)</td> <td>Gary Rudder</td> <td></td> </tr> <tr> <td>Frequency Response Surveys</td> <td>Doug Hils</td> <td></td> </tr> <tr> <td>Inadvertent Interchange Reports (East)</td> <td>Howard Illian</td> <td></td> </tr> <tr> <td>Inadvertent Interchange Reports (West)</td> <td>Grant Griffith</td> <td></td> </tr> <tr> <td>Time Error Reports (East)</td> <td>Al DiCaprio</td> <td></td> </tr> <tr> <td>Time Error Reports (West)</td> <td>Grant Griffith</td> <td></td> </tr> <tr> <td>ERCOT Reports</td> <td>Dennis Hogan</td> <td></td> </tr> </table>			Control Performance Criteria Survey	Bill Phillips		Area Interchange Error Surveys (East)	Gary Rudder		Frequency Response Surveys	Doug Hils		Inadvertent Interchange Reports (East)	Howard Illian		Inadvertent Interchange Reports (West)	Grant Griffith		Time Error Reports (East)	Al DiCaprio		Time Error Reports (West)	Grant Griffith		ERCOT Reports	Dennis Hogan	
Control Performance Criteria Survey	Bill Phillips																									
Area Interchange Error Surveys (East)	Gary Rudder																									
Frequency Response Surveys	Doug Hils																									
Inadvertent Interchange Reports (East)	Howard Illian																									
Inadvertent Interchange Reports (West)	Grant Griffith																									
Time Error Reports (East)	Al DiCaprio																									
Time Error Reports (West)	Grant Griffith																									
ERCOT Reports	Dennis Hogan																									

Performance Subcommittee

Chairman MAAC	Albert M. DiCaprio Senior Engineer	PJM Interconnection Association 955 Jefferson Avenue Valley Forge Corporate Center Norristown, Pennsylvania 19403-2497	Ph: 610-666-8854 Fx: 610-666-4282
Vice Chairman ERCOT	Dennis B. Hogan Senior Engineer	TU Electric 2233-B Mt. Creek Parkway Dallas, Texas 75211	Ph: 214-944-7477 Fx: 214-263-6710
Vice Chairman WSCC	Edward R. Riley Manager, Bulk Power Dispatching	Los Angeles Department of Water & Power P.O. Box 111 ECC c/o rm 1243 Los Angeles, California 90051	Ph: 818-771-6744 Fx: 818-771-6580
ECAR	Douglas E. Hils Manager, Control Area Operations	Cinergy 139 East 4th Street Room 651-Annex Cincinnati, Ohio 43202	Ph: 513-287-2149 Fx: 513-287-3812
ERCOT	Thomas I. Brown, III Fuel/Production Coordinator	Central and South West Services, Inc. P.O. Box 660164 Dallas, Texas 75266-0164	Ph: 214-777-3121 Fx: 214-777-1429
FRCC	Don McInnis Supervisor of Operations Engineering	Florida Power & Light Company P.O. Box 029311 Miami, Florida 33102-9311	Ph: 305-442-5272 Fx: 305-442-5022
MAIN	Terry Bilke System Control Supervisor	Wisconsin Electric Power Company System Control Center W237 N 1500 Busse Road Waukesha, Wisconsin 53188	Ph: 414-544-7119 Fx: 414-544-7099
MAPP	Alan R. Oneal Senior Engineer	MidAmerican Energy Company P.O. Box 657 Des Moines, Iowa 50303	Ph: 515-252-6449 Fx: 515-252-6410
NPCC	Michael J. Potishnak Principal Engineer	New England Power Pool One Sullivan Road Holyoke, Massachusetts 01040-2841	Ph: 413-535-4308 Fx: 413-535-4343
NPCC	Wayne D. Smith Section Head, Commercial Development Wholesale Markets	Ontario Hydro 700 University Avenue H5-F3 Toronto, Ontario M5G 1X6	Ph: 416-592-5705 Fx: 416-592-4069

SERC	Gary W. Rudder Electric System Operations Operations and Interface Specialist	Tennessee Valley Authority 1101 Market Street MRBA Chattanooga, Tennessee 37402-2801	Ph: 423-751-7917 Fx: 423-751-7346
SPP	William C. Phillips Director - Security Operations	Southwest Power Pool 415 North McKinley Plaza West -- #700 Little Rock, Arkansas 72205-3020	Ph: 501-664-0146 Fx: 501-664-9553
RMPA WSCC	Jaromir J. Horenovsky Manager, System Operations	Colorado Springs Utilities P.O. Box 1103 Mail Code 1321 Colorado Springs, Colorado 80947	Ph: 719-668-4020 Fx: 719-636-9392
NWPP WSCC	Grant E. Griffith Operations Engineer	Northwest Power Pool Coordinating Group 26 SW Salmon Portland, Oregon 97204-2991	Ph: 503-464-2809 Fx: 502-464-2819
AZ-NM WSCC	B. Phil Clark Coordinator, System Performance	Tucson Electric Power Company P.O. Box 711 Tucson, Arizona 85702	Ph: 602-745-7104 Fx: 602-745-3348
Staff Coordinator NERC	Colin L. Wright Operations Analyst	North American Electric Reliability Council 116-390 Village Boulevard Princeton, New Jersey 08540-5731	Ph: 609-452-8060 Fx: 609-452-9550

X-POP3-Rcpt: barbara@nerc1
Return-Path: majordomo-owner
Date: Mon, 14 Apr 1997 16:15:38 -0400
X-Authentication-Warning: nerc1.nerc.com: majordomo set sender to majordomo-owner using -f
To: barbara@nerc.com
From: majordomo@nerc1.nerc.com
Subject: Majordomo results: list
Reply-To: majordomo@nerc1.nerc.com

--

>>>> who perfsup
Members of list 'perfsup':

tbrown@csu.com (Tom Brown)
wayne.smith@HYDRO.ON.CA (Wayne Smith)
GWRudder@tva.gov (Gary Rudder)
Don_McInnis@email.fpl.com (Don McInnis)
rmitch1@entergy.com (Wayne Mitchell)
bpclark@primenet.com (Byron P. Clark)
cwright@nerc.com (Colin Wright)
skoch@csu.org (Susan Koch for Mirek Horenovsky)
dicapram@pjm.com (Al DiCaprio)
dhils@cinergy.com (Doug Hils)
aroneal@midamerican.com (Alan Oneal)
dhogan2@tuelectric.com (Dennis Hogan)
grant_griffith@pgn.com (Grant Griffith)
eriley@ladwp.com (Ed Riley)
wphillips@spp.org (Bill Phillips)
barbara@nerc.com
idx13@tva.gov
mhorenovsky@csu.org
csander@entergy.com
TERRY.BILKE@wemail.wisenergy.com

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL
PERFORMANCE SUBCOMMITTEE SURVEY CONTACTS

Type:	Date:	Time:	Survey Called:	Due By:
CONTACT	REGION	PHONE	CALL	REC.
Doug Hils* Dean Mathey-ECAR office	ECAR	(513) 287-2149 (330) 456-2488		
Dennis Hogan So. Texas Security Center Operator*	ERCOT	(214) 743-6843 (512) 482-6276		
Don McInnis*	FRCC	(305) 442-5272		
Al DiCaprio Bob Walsh*	MAAC	(610) 666-8854 (610) 666-8858		
Terry Bilke Joe O'Brien*	MAIN	(414) 544-7119 (630) 261-2620		
Alan Oneal* Tom Patridge (MAPP office)	MAPP	(515) 224-6100 (612) 341-4671		
Mike Potishnak*	NPCC	(413) 535-4308		
Gary Rudder Bud Pressley*	SERC	(423) 751-7917 (423) 751-3008		
Bill Phillips Bruce Rew*	SPP	(501) 664-0146 (501) 664-0146		
Phil Clark*	WSCC/AZNM	(602) 745-7104		
Ed Riley* Perpetuo S.V. Tan Greg Rogers	WSCC/CANV	(818) 771-6744 (818) 771-6776 (818) 771-6777		
Grant Griffith Pam Hunt-CPC, INAD*	WSCC/NWPP	(503) 464-2809 (503) 464-2816		
Mirek Horenovsky Sue Koch*	WSCC/RMPP	(719) 668-4020 (719) 668-4021		
TIME CORRECTIONS: System CoordinatorMAPP Art Storey-NYPP Art Haas-AEP		(612) 341-4690 (518) 356-6111 (614) 223-3406		

*Primary Contact

January 31, 1997-February 6, 1997 AIE Survey

After reviewing the average performance over the past several Eastern Interconnection AIE surveys at its July 25-26, 1996 meeting, the Subcommittee flagged the following control areas. The list was based on those areas:

- who had a positive adjusted AIE error of 150% or higher for more than 12 of the 15 high frequency hours (one of the 16 hours in the March 15-18 survey had a low frequency average over the hour), and
- whose average (straight average, NOT absolute value of errors) across the 15 hours was 50% or greater.

These systems are:

MAIN	Central Illinois Light Company
SPP	Kansas City Power & Light Company
ECAR	The Dayton Power & Light Company
SERC	South Carolina Electric & Gas Company
NPCC	New York Power Pool
MAPP	IES Utilities
ECAR	Hoosier Energy Rural Electric Coop
ECAR	Allegheny Power System
SPP	Southwestern Power Administration
ECAR	Duquesne Light Company
MAIN	Wisconsin Electric Power Company
SERC	South Carolina Public Service
ECAR	Cinergy Corporation
ECAR	Southern Indiana Gas & Electric Company
MAPP	Minnesota Power Company
ECAR	Louisville Gas and Electric Company
ECAR	Northern Indiana Public Service Company

The Subcommittee agreed at that meeting that any of the above areas would be removed from the list if their next survey compliance was below the 150% L_d limit.

Colin Wright will present performance information for these and all areas for the January 31-February 6, 1997 AIE survey for comparison.

Action: Discuss

1998, 1999, and 2000 Off-Peak Days

Below is a list of suggested additional off-peak days for 1998, 1999, and 2000 (to be used in Appendix 1F). Due to a large number of long term inquiries it would be helpful to the NERC staff for the Subcommittee to select the off-peak days for the upcoming three years.

1998	New Year's Day	January 1	Thursday
	Memorial Day	May 25	Monday
	Labor Day	September 7	Monday
	Thanksgiving Day	November 26	Thursday
	Christmas Day	December 25	Friday
1999	New Year's Day	January 1	Friday
	Memorial Day	May 31	Monday
	Labor Day	September 6	Monday
	Thanksgiving Day	November 25	Thursday
	Christmas Eve Day	December 24	Friday
	New Year's Eve Day	December 31	Friday
2000	Memorial Day	May 29	Monday
	Independence Day	July 4	Tuesday
	Labor Day	September 4	Monday
	Thanksgiving Day	November 23	Thursday
	Christmas Day	December 25	Monday

Action: Discuss and approve.

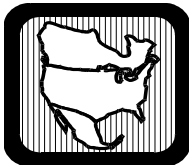
**Agenda Item 12
PS Meeting
April 24-25, 1997**

**Performance Subcommittee
EC/OC
Future Meeting Dates**

Performance Subcommittee Meetings	
April 23-25, 1997	Coeur d'Alene P.O. Box 7200 Coeur d'Alene, ID 208-765-4000
October 1998	Regency Vancouver Harrard Street Vancouver, B.C. 604-273-1234
January 1999	

EC/OC Meetings	
July 8-9, '97	Quebec City, QU
November 18-19, '97	New Orleans, LA
March 10-11, '98	Salt Lake City, UT
July 14-15, '98	Vancouver, BC
November 17-18, '98	Jacksonville, FL

IEEE PES General Meetings		
1997 Summer Power Meeting	July 20-25	Berlin, Germany
1998 Winter Power Meeting	January 31-February 5	Tampa
1998 Summer Power Meeting	July 11-17	San Diego



North American Electric Reliability Council

Princeton Forrestal Village, 116-390 Village Boulevard, Princeton, New Jersey 08540-5731

CONTROL CRITERIA TASK FORCE MEETING

Thursday, April 24, 1997 — 8 a.m.–noon

The Coeur d'Alene
Coeur d'Alene, Idaho

AGENDA

1. Administrative Matters

- a. Introductions
- b. Arrangements — Colin L. Wright
- c. Approval of Minutes of January 23, 1997 Meeting — Colin L. Wright
- d. Approval of Agenda
- e. Roster*

2. Task Force Reports

- a. Frequency Task Force — Howard F. Illian
 - i) Report on Structure for Frequency Standard
 - ii) Frequency Benchmarking Results for Interconnections
- b. Inadvertent Task Force — Bart McManus
 - i) Draft Report on Metering Data Issues
- c. Reserves Task Force — Wayne R. Smith
 - i) Draft Report on Reserves Distribution Issues — Mirek Horenovsky
 - ii) Draft Report on Contingency Reserves Definitions — Don McInnis
 - iii) Draft Revision of Policy 1.A. — Wayne Smith
- d. Operator Interface Task Force — Edward R. Riley
 - i) Status of Planned PICA Panel Session
 - ii) Draft Report on MMI
 - iii) Status of Survey to Document MMI/Algorithm Modifications
- e. Task Force meeting structure

3. Schedule of completion for new Standards development

4. CPS and DCS Matters

- a. Noteworthy Experiences with CPS or DCS
- b. Implementation Reports/Problems
- c. Issues with DCS; SERC
- d. CPS epsilon limits — Is our current selection appropriate in light of the FTF's Findings?

Control Criteria Task Force

Chairman MAPP	Alan R. Oneal Senior Engineer	MidAmerican Energy Company P.O. Box 657 Des Moines, Iowa 50303	Ph: 515-252-6449 Fx: 515-252-6410
	Warren McReynolds Manager of Technical Operations	Bonneville Power Administration P.O. Box 491 Vancouver, Washington 98666	Ph: 360-418-2344 Fx: 360-418-2963
ECAR	Robert R. Thompson Engineer, Network Planning Transmission Business Unit	Allegheny Power 800 Cabin Hill Drive Greensburg, Pennsylvania 15601-1689	Ph: 412-838-6479 Fx: 412-838-5139
ECAR	Dan E. Goldman Project Leader, Strategic Planning	Northern Indiana Public Service Company 801 E. 86th Street Merrillville, Indiana 46411	Ph: 219-647-4884 Fx: 219-647-5517
ECAR	William H. Clark Project Leader, Strategic Planning	Northern Indiana Public Service Company 801 E. 86th Street Merrillville, Indiana 46411	Ph: 219-647-4442 Fx: 219-647-5517
ECAR	Robert A. Kramer Manager, Technical Support	Northern Indiana Public Service Company 801 E. 86th Street Merrillville, Indiana 46411	Ph: 219-647-5500 Fx: 219-647-5517
ECAR	Douglas E. Hils Manager, Control Area Operations	Cinergy 139 East 4th Street Room 651-Annex Cincinnati, Ohio 43202	Ph: 513-287-2149 Fx: 513-287-3812
ERCOT	Dennis B. Hogan Senior Engineer	TU Electric 2233-B Mt. Creek Parkway Dallas, Texas 75211	Ph: 214-944-7477 Fx: 214-263-6710
ERCOT	Thomas I. Brown, III Fuel/Production Coordinator	Central and South West Services, Inc. P.O. Box 660164 Dallas, Texas 75266-0164	Ph: 214-777-3121 Fx: 214-777-1429
FRCC	Don McInnis Supervisor of Operations Engineering	Florida Power & Light Company P.O. Box 029311 Miami, Florida 33102-9311	Ph: 305-442-5272 Fx: 305-442-5022

MAAC	Albert M. DiCaprio Senior Engineer	PJM Interconnection Association 955 Jefferson Avenue Valley Forge Corporate Center Norristown, Pennsylvania 19403-2497	Ph: 610-666-8854 Fx: 610-666-4282
MAIN	Terry Bilke System Control Supervisor	Wisconsin Electric Power Company System Control Center W237 N 1500 Busse Road Waukesha, Wisconsin 53188	Ph: 414-544-7119 Fx: 414-544-7099
NPCC	Michael J. Potishnak Principal Engineer	New England Power Pool One Sullivan Road Holyoke, Massachusetts 01040-2841	Ph: 413-535-4308 Fx: 413-535-4343
NPCC	Wayne D. Smith Section Head, Commercial Development Wholesale Markets	Ontario Hydro 700 University Avenue H5-F3 Toronto, Ontario M5G 1X6	Ph: 416-592-5705 Fx: 416-592-4069
SERC	Raymond L. Vice Manager Operations Engineering	Southern Company Services, Inc. P.O. Box 2625 Birmingham, Alabama 35202-2625	Ph: 205-257-6209 Fx: 205-257-6663
SERC	Gary W. Rudder Electric System Operations Operations and Interface Specialist	Tennessee Valley Authority 1101 Market Street MRBA Chattanooga, Tennessee 37402-2801	Ph: 423-751-7917 Fx: 423-751-7346
SPP	Charles W. Sanders Senior Staff Engineer	Entergy Services, Inc. P.O. Box 6100 Pine Bluff, Arkansas 71611	Ph: 501-543-5448 Fx: 501-541-3936
SPP	William C. Phillips Director - Security Operations	Southwest Power Pool 415 North McKinley Plaza West -- #700 Little Rock, Arkansas 72205-3020	Ph: 501-664-0146 Fx: 501-664-9553
WSCC	Bart McManus Automatic Generation Control System Operations-TOS	Bonneville Power Administration P.O. Box 491 Vancouver, Washington 98666	Ph: 360-418-2309 Fx: 360-418-8186
WSCC	Michael McAvoy Senior Electrical Engineer	City of Colorado Springs Department of Public Utilities P.O. Box 1103 Colorado Springs, Colorado 80947	Ph: 719-668-4028

Fx: 719-636-9392

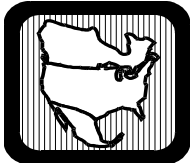
WSCC	Jaromir J. Horenovsky Manager, System Operations	Colorado Springs Utilities P.O. Box 1103 Mail Code 1321 Colorado Springs, Colorado 80947	Ph: 719-668-4020 Fx: 719-636-9392
NWPP WSCC	Grant E. Griffith Operations Engineer	Northwest Power Pool Coordinating Group 26 SW Salmon Portland, Oregon 97204-2991	Ph: 503-464-2809 Fx: 502-464-2819
WSCC	Edward R. Riley Manager, Bulk Power Dispatching	Los Angeles Department of Water & Power P.O. Box 111 ECC c/o rm 1243 Los Angeles, California 90051	Ph: 818-771-6744 Fx: 818-771-6580
WSCC	B. Phil Clark Coordinator, System Performance	Tucson Electric Power Company P.O. Box 711 Tucson, Arizona 85702	Ph: 602-745-7104 Fx: 602-745-3348
Consultant	Mike Sutherland Statistical Consulting Center	University of Massachusetts at Amherst 320 Lederle Graduate Research Center Amherst, Massachusetts 01003	Ph: 413-545-1522 Fx: 413-545-1801
Consultant	Louis S. VanSlyck Priority-based Control Engineering	6063 Frantz Road Suite 205 Dublin, Ohio 43017-3370	Ph: 614-799-0300 Fx: 614-799-0400
Consultant	Nasser Jaleeli President	Priority-based Control Engineering 6063 Frantz Road Suite 205 Dublin, Ohio 43017-3370	Ph: 614-799-0300 Fx: 614-799-0400
EPRI	Dominic Maratukulam Manager, System Design	Electric Power Research Institute P.O. Box 10412 Palo Alto, California 94303	Ph: 415-855-7974 Fx: 415-855-8997
Staff Coordinator NERC	Colin L. Wright Operations Analyst	North American Electric Reliability Council 116-390 Village Boulevard Princeton, New Jersey 08540-5731	Ph: 609-452-8060 Fx: 609-452-9550

X-POP3-Rcpt: barbara@nerc1
Return-Path: majordomo-owner
Date: Thu, 16 Jan 1997 15:04:58 -0500
X-Authentication-Warning: nerc1.nerc.com: majordomo set sender to majordomo-owner using -f
To: barbara@nerc.com
From: majordomo@nerc1.nerc.com
Subject: Majordomo results: list
Reply-To: majordomo@nerc1.nerc.com

--

>>>> who cctf
Members of list 'cctf':

tbrown@csu.com (Tom Brown)
wayne.smith@HYDRO.ON.CA (Wayne Smith)
GWRudder@tva.gov (Gary Rudder)
Don_McInnis@email.fpl.com (Don McInnis)
bpclark@primenet.com (Byron P. Clark)
bamcmanus@bpa.gov (Bart McManus)
wlmcreynolds@bpa.gov (Warren MCreynolds)
mikes@math.umass.edu (Mike Sutherland)
dmaratuk@paloalto.epri.com (Dominik Maratukulam)
cwright@nerc.com (Colin Wright)
bposh@bpo-ess.ceco.com (Stephen Hoffman)
mpotishnak@nepool.com (Mike Potishnak)
nasser@grdata.com (Nasser Jaleeli of PCE)
skoch@csu.org (Susan Koch for Mirek Horenovsky)
dicapram@pjm.com (Al DiCaprio)
rakramer@nipsco.com (Bob Kramer)
dhils@cinergy.com (Doug Hils)
aroneal@midamerican.com (Alan Oneal)
dhogan2@tuelectric.com (Dennis Hogan)
grant_griffith@pgn.com (Grant Griffith)
eriley@ladwp.com (Ed Riley)
wphillips@spp.org (Bill Phillips)
raymond.l.vice@scsnet.com (Raymond Vice)
barbara@nerc.com
TERRY.BILKE@wemail.wisenergy.com



North American Electric Reliability Council

Princeton Forrestal Village, 116-390 Village Boulevard, Princeton, New Jersey 08540-5731

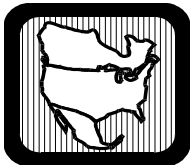
FREQUENCY TASK FORCE MEETING

Wednesday, April 23, 1997 — 8 a.m.–noon

The Coeur d'Alene
Coeur d'Alene, Idaho

AGENDA

1. **Administrative Matters**
 - a. Approval of Agenda
2. **Review of Draft Frequency Standard Structure Report**
3. **Update on Frequency Benchmarking Efforts for Each Interconnection**
4. **Subsequent Work**
 - a. Schedule of completion for new Standards development
 - b. Changes to relevant sections of Policy 1
 - c. Discuss Homework Assignments



North American Electric Reliability Council

Princeton Forrestal Village, 116-390 Village Boulevard, Princeton, New Jersey 08540-5731

INADVERTENT TASK FORCE MEETING

Wednesday, April 23, 1997 — 10 a.m.-3 p.m.

The Coeur d'Alene
Coeur d'Alene, Idaho

AGENDA

1. Administrative Matters

- a. Introductions
- b. Approval of Agenda

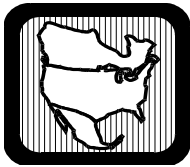
2. Draft Report On Billing Meter Data Versus Operating Data

- a. How can the double book problem be resolved?
 - i. Ensure that same changes are made in both
 - ii. Don't allow bills to go out until inadvertent is balanced
 - iii. If inadvertent is not submitted by the 20th of the following month, those submitted by adjoining control areas would be accepted as the true inadvertent.

3. Adverse Power Flows

4. Subsequent Work

- a. Schedule of completion for new Standards development
- b. Changes to relevant sections of Policy 1
- c. Discuss Homework Assignments



North American Electric Reliability Council

Princeton Forrestal Village, 116-390 Village Boulevard, Princeton, New Jersey 08540-5731

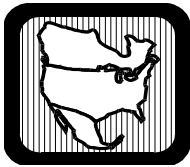
OPERATOR INTERFACE TASK FORCE MEETING

Wednesday, April 23, 1997 — 10 a.m.-3 p..m.

The Coeur d'Alene
Coeur d'Alene, Idaho

AGENDA

- 1. Administrative Matters**
 - a. Introductions
 - b. Approval of Agenda
- 2. Review of Regional Survey on Plans for MMI and/or Control Algorithm**
- 3. Review of Draft Report Discussing Issues Associated with a Good Man-Machine Interface**
- 4. Update on panel session at the PICA Conference in Columbus, Ohio**
- 5. Subsequent Work**
 - a. Schedule of completion for new Standards development
 - b. Changes to relevant sections of Policy 1
 - c. Discuss Homework Assignments



North American Electric Reliability Council

Princeton Forrestal Village, 116-390 Village Boulevard, Princeton, New Jersey 08540-5731

RESERVE TASK FORCE MEETING

Wednesday, April 23, 1997 — 1 p.m.-5 p.m.

The Coeur d'Alene
Coeur d'Alene, Idaho

AGENDA

1. **Administrative Matters**
 - a. Introductions/Membership
2. **Approval of Agenda**
3. **Reserves Strawman Review**
 - a. Reserves Distribution Issues — Mirek Horenovsky
 - b. Contingency Reserves Definitions — Don McInnis
 - c. Review of Policy 1A — Strawman — Wayne Smith*
 - d. Donald M. Benjamin's strawman*
4. **Subsequent Work**
 - a. Schedule of completion for new Standard development
 - b. Changes to relevant sections of Policy 1
 - c. Discuss Homework Assignments

Operating Reserve Strawman

Terms Used in the Policies

(Related to Policy 1 on Operating Reserve)

Area Control Error (ACE). The instantaneous difference between net actual and scheduled interchange, taking into account the effects of frequency bias including a correction for meter error.

Automatic Generation Control (AGC). Equipment which automatically adjusts a control area's generation from a central location to maintain its interchange schedule plus frequency bias.

Commonly or Jointly Owned Units (COU/JOU). These terms may be used interchangeably to refer to a unit in which two or more control areas share ownership.

Control Area. An electrical system bounded by interconnection (tie-line) metering and telemetry. It controls its generation directly to maintain its interchange schedule with other control areas and contributes to frequency regulation of the Interconnection.

Disturbance. 1. Any perturbation to the electric system. 2. The unexpected change in ACE that is caused by the sudden loss of generation or interruption of load.

First Contingency. The largest net MW loss due to a credible single contingency. A detailed definition must appear in Regional Reliability Council policy and must reflect any unique reliability requirements of the region. As a minimum, all regions must consider the loss of any generating unit and the loss though an electrical fault of a circuit greater than x miles in length.

Interruptible Load. Demand that can be interrupted by direct action of the supplying system's system operator in accordance with contractual provisions.

Load. The amount of electric power delivered or required at any specified point or points on a system.

Non-spinning Reserve. That operating reserve not connected to the system but capable of serving demand within a specified time, or interruptible load that can be removed from the system in a specified time.

Operating Reserve. That capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages and local area protection. It consists of spinning and non-spinning reserve.

Reserve sharing group. A group whose members consist of two or more control areas that collectively maintain, allocate, and supply operating reserves required for each control area's use in recovering from contingencies within the group. Scheduling energy in from an adjoining control area to aid recovery need not constitute reserve sharing provided the transaction is ramped in over a period which the supplying party could reasonably be expected to load generation in (e.g., ten minutes). If the transaction is ramped in quicker (e.g., between zero and ten minutes) then, for the purposes of Disturbance Control Performance, the areas become a reserve sharing group.

Reportable Disturbance. A disturbance in size less than or equal to a CONTROL AREA's or RESERVE SHARING GROUP's most severe single contingency and greater than or equal to a lower threshold as set by the Regional Reliability Council. A Regional Reliability Council may not set the lower threshold above 80% of the most severe single contingency.

Spinning Reserve. Unloaded generation which is synchronized and ready to serve additional demand.

Policy 1 — Generation Control and Performance

(Sections Related to Operating Reserve)

A. Operating Reserve

[Appendix 1A – Area Control Error Equation]
[Performance Standard Training Document]

Criteria

Each CONTROL AREA shall operate its MW power resources to provide for a level of OPERATING RESERVE sufficient to account for such factors as generation and transmission equipment unavailability, number and size of generating units, system equipment forced outage rates, maintenance schedules, regulating requirements, and Regional and system load diversity. Following loss of resources or load, a CONTROL AREA shall take appropriate steps to restore its AREA CONTROL ERROR to meet the Disturbance Control Standard (DCS). It shall take prompt steps to protect itself against the next contingency.

Each Region, subregion or RESERVE SHARING GROUP shall specify its operating reserve policies, including the minimum reserve requirement for the group, its allocation among members, the permissible mix of SPINNING RESERVE and nonspinning reserve, and procedure for applying operating reserve in practice, and the limitations, if any, upon the amount of interruptible load which may be included.

Standards

1. **Disturbance conditions.** The Disturbance Control Standard shall be used by each control area or reserve sharing group to monitor control performance during recovery from disturbance conditions (see the “Performance Standard Training Document,” Section B.2):
 - 1.1 **Disturbance Control Standard (DCS).** Each CONTROL AREA or RESERVE SHARING GROUP shall meet the Disturbance Control Standard (DCS) 100% of the time for REPORTABLE DISTURBANCES (see the “Performance Standard Training Document,” Section C).
 - 1.2 **Disturbance Control Performance Adjustment.** Each CONTROL AREA or RESERVE SHARING GROUP not satisfying the Disturbance Control Standard during a given quarter, shall increase its Operating Reserve Requirement for the calendar quarter (offset by a month) following the evaluation. The increase shall be directly proportional to the control area’s or reserve sharing group’s non-compliance to the Disturbance Control Standard. (See the “Performance Standard Training Document,” Section C.)

Requirements

1. **Operating reserve distribution.** OPERATING RESERVE shall be dispersed throughout the system and shall consider the effective use of capacity in an emergency, time required to be effective, transmission limitations, and local area requirements. (More detail required)
2. **Contingency review.** All Regions, subregions, RESERVE SHARING GROUPS, and CONTROL AREAS shall

continually review probable contingencies to determine the adequacy of operating reserve. All regions must demonstrate to NERC the adequacy of their first contingency definition.

3. **Operating Reserve.** Each Region, subregion, or RESERVE SHARING GROUP shall specify, and each CONTROL AREA shall provide, as a minimum, OPERATING RESERVE sufficient to reduce AREA CONTROL ERROR to meet the Disturbance Control Standard.
 - 3.1. **Spinning reserve.** SPINNING RESERVE is considered the most trusted form of OPERATING RESERVE . At least 50% of OPERATING RESERVE shall Be SPINNING RESERVE.
 - 3.1.1. **Jointly owned generation with dynamic schedules.** CONTROL AREAs that share JOINTLY OWNED UNITS and incorporate DYNAMIC SCHEDULES or PSEUDO-TIES shall include only their share of the unit in their SPINNING RESERVE calculations.
 - 3.1.2. **Jointly owned generation with fixed schedules.** CONTROL AREAs receiving their share of JOINTLY OWNED UNITS as fixed schedules should not include the jointly owned units' share(s) on which the schedules are based in their SPINNING RESERVE calculations. The CONTROL AREA in which the jointly owned unit resides may include the SPINNING RESERVES for its share of the unit.
 - 3.1.2. **Reduction in SPINNING RESERVE.** The SPINNING RESERVE component may be reduced below 50% of the OPERATING RESERVE providing the CONTROL AREA, or all CONTROL AREA's in a RESERVE SHARING GROUP, are CPS1 and CPS2 compliant based on the most recent NERC reporting. The terms and degree of reduction must be detailed in Regional Reliability Council policy but must not reduce spinning reserve below 25% of the OPERATING RESERVE
 - 3.2. **Reserve sharing group.** Each RESERVE SHARING GROUP shall comply with the Disturbance Control Standard as if it were a single CONTROL AREA. A RESERVE SHARING GROUP shall be considered in a DISTURBANCE condition any time a group member is in a DISTURBANCE condition and calls for reserves. Compliance may be demonstrated in either of the following two methods:
 - 3.2.1. **Group compliance to Disturbance Control Standard.** The RESERVE SHARING GROUP reviews group ACE (or equivalent) and demonstrates compliance.
 - 3.2.2. **Group member compliance to Disturbance Control Standard.** The RESERVE SHARING GROUP reviews each member's ACE in response to a call for reserves; to be in compliance each member's ACE must return to zero or to its respective pre-disturbance level within ten minutes of the start of the DISTURBANCE.
 - 3.2.3. **Reserve Sharing Group monitoring.** Each RESERVE SHARING GROUP shall monitor operating reserve availability and actual response.
 - 3.4. **INTERRUPTIBLE LOAD.** INTERRUPTIBLE LOAD may be included in the non-spinning reserve provided that it can be interrupted within ten minutes.

- 3.5. **Jointly owned generation in another CONTROL AREA.** CONTROL AREAS using fixed schedules for JOINTLY OWNED UNITS that reside outside their CONTROL AREA may include their share of the facility in their OPERATING RESERVE calculations. The OPERATING RESERVE is constrained by their share of the unit(s) capability and their share of the unit(s) ramp capability achievable over a ten-minute period. Included in the ten minutes is the time necessary to schedule the generation into the CONTROL AREA.
- 3.4.8 **Reestablishing OPERATING RESERVE.** A CONTROL AREA or RESERVE SHARING GROUP must reestablish its OPERATING RESERVE within 60 minutes of a contingency. Regional Reliability Council policy may set a more constraining requirement.
4. **Disturbance Control Requirement** The ACE must return either to zero or to its pre-disturbance level within ten minutes following the start of any disturbance whether or not it qualifies as a REPORTABLE EVENT and is included under DCS.

E. Performance Standard

Effective Beginning Feb. 1, 1997

Compliance Expected Feb. 1, 1998

[Appendix 1H – Minimum Data Collection Requirements
for Use in Monitoring NERC Performance Standards]
[Performance Standard Training Document]

Introduction

The Control Performance Standard (CPS) define a standard of minimum control performance. Each CONTROL AREA is to have the best operation above this minimum that can be achieved within the bounds of reasonable economic and physical limitations.

Standards

1. **Continuous Monitoring.** Each control area shall monitor its control performance on a continuous basis against two Standards: CPS1 and CPS2.
 - 1.1. **Control Performance Standard (CPS1).** Over a year, the average of the clock-minute averages of a control area's ACE divided by $-10B$ (B is control area frequency bias) times the corresponding clock-minute averages of Interconnection's frequency error shall be less than a specific limit. This limit, ϵ , is a constant derived from a targeted frequency bound reviewed and set as necessary by the NERC Performance Subcommittee.
 - 1.2. **Control Performance Standard (CPS2).** The average ACE for each of the six ten-minute periods during the hour (i.e., for the ten-minute periods ending at 10, 20, 30, 40, 50, and 60 minutes past the hour) must be within specific limits, referred to as L_{10} . See the "Performance Standard Training Document," Section B.1.1.2 for the methods for calculating L_{10} .

Requirements

1. **ACE values.** The ACE used to determine compliance to the Control Performance Standards shall reflect its actual value, and exclude short excursions due to transient telemetering problems or other influences

such as control algorithm action.

2. **Control Performance Standard (CPS) Compliance.** Each CONTROL AREA shall achieve CPS1 compliance of 100% and achieve CPS2 compliance of 90% (see the "Performance Standard Training Document," Section C).
3. **PS Surveys.** All CONTROL AREAS shall respond to control performance surveys that are requested by the Performance Subcommittee.

G. Control Surveys

[Area Interchange Error Survey Training Document]
[Frequency Response Characteristic Survey Training Document]
[Performance Standard Training Document]

Criteria

Periodic surveys of the performance of the CONTROL AREAS shall be conducted. These surveys serve the purpose of revealing control equipment malfunctions, telemetering errors, improper frequency bias settings, scheduling errors, inadequate generation under automatic control, general control performance deficiencies, or other factors contributing to inadequate control performance.

Requirements

1. **Surveys.** The CONTROL AREAS in each INTERCONNECTION shall perform each of the following surveys, as described in the Performance Standard Training Document, when called for by the Performance Subcommittee:
 - 1.1. **AIE survey.** Area Interchange Error survey to determine the CONTROL AREAS' INTERCHANGE error(s) due to equipment failures or improper SCHEDULING operations, or improper AGC performance.
 - 1.2. **FRC survey.** Area Frequency Response Characteristic survey to determine the CONTROL AREAS' response to changes in system frequency.
 - 1.3. **CPS and DCS surveys.** Performance Standard surveys to monitor the CONTROL AREAS' control performance during normal and DISTURBANCE situations.
 - 1.3.1 **Control Performance Surveys**
 - 1.3.2 **Disturbance Control Surveys.** Each control area or reserve sharing group shall submit a quarterly summary report to their Regional Performance Subcommittee representative of the respective control area's compliance to the DCS during the reporting quarter.

**Agenda Item 3d
Reserves TF Meeting
April 23, 1997**

X-POP3-Rcpt: cwright@nerc1
Return-Path: owner-perfsub
From: wayne.smith@HYDRO.ON.CA
X-Authentication-Warning: torrent: Host usenet.Hydro.ON.CA claimed to be usenet.Hydro.ON.CA
To: perfsub@nerc.com, don.benjamin@nerc.com
Subject: NERC: OR Task Force - Strawman
Date: Fri, 04 Apr 97 09:48:00 EST

To: perfsub@nerc.com, don.benjamin@nerc.com

To: Operating Reserve Task Force
Performance Sub, for interest

The strawman I sent out in March provoked a lot of discussion as I hoped. However, as I have seen it, the discussion was mostly outside the Performance Subcommittee. In response of IOSWG concern, Don Benjamin has produced a great strawman for policy 1A. (attached)

Please read it before our next meeting in a few weeks.

Take his structure as the one we want. However, and continuing to be deliberately provocative, here are some comments to consider.

Should a requirement of operating reserve be tied to frequency response? First, operating reserve, even spinning reserve, does not guarantee any amount of frequency response - reserve is measured over 10 minutes, frequency response, from governor action, is over a period of 20 seconds. Second - load response is an equally credible source of frequency response. To set a NERC requirement tied to response from only generation may not be defensible. Third - there is plan for a frequency response standard, would a duplicate requirement not be an unnecessary restriction.

Should a requirement of operating reserve be tied to control? There is a control performance standard, would a duplicate requirement not be an unnecessary restriction. Can we say that x amount of reserve is equivalent to the requirements of the CPS.

Is there even a need for a spinning reserve requirement. Yes it is in FERC. However, the goal is to not be a barrier to commerce. If frequency response and control are adequately ensured by other standards/requirements do we need to duplicate their intent with a more constraining operating reserve standard. NERC standards should be as comprehensible and as actionable as possible.

Out of the next meeting we need to be in the position to produce a serious and acceptable strawman. Please consider the possibility of a one day meeting in May/June at a convenient location.

Wayne Smith

Policy 1 – Generation Control and Performance

Introduction to Policy 1

Control areas are responsible for operating their generation resources to comply with NERC’s CONTROL PERFORMANCE STANDARD and DISTURBANCE CONTROL STANDARD and help maintain the operational security of the Interconnection. Generation resources include on- and off-line generation that is within the metered boundaries of the control area, resources available through arrangements with RESERVE SHARING GROUPS, and resources available through INTERCHANGE TRANSACTIONS. Generation resources may consist of those operated directly by the control area and those operated by independent power producers through contractual arrangements with the control area.

A. Operating Reserve

Introduction

OPERATING RESERVE is a broad term that usually refers to *unloaded* generation, either on-line (SPINNING RESERVE) or off-line (SUPPLEMENTAL RESERVE), plus, in some cases, demand-side management.

As it relates to these Policies, SPINNING RESERVE is defined as *unloaded, on-line* without regard to primary or secondary control equipment. In some cases, curtailable load can also be counted as SPINNING RESERVE. SUPPLEMENTAL RESERVE is defined as *unloaded, off-line* generation.

A control area must also maintain sufficient SECONDARY RESERVES to replace SPINNING and SUPPLEMENTAL RESERVES when they are used.

A generator that is carrying SPINNING RESERVE and not at minimum load can either increase or decrease its output, and therefore, has MANEUVERING CAPABILITY. (See Figure 1).

A generator with MANEUVERING CAPABILITY and a governor can respond to both frequency increases and decreases according to its droop characteristic, and help a control area meet its Area Interchange Error requirements.

A generator with MANEUVERING CAPABILITY and load-frequency control that responds to automatic generation control signals can help a control area meet its Control Performance and Disturbance Control requirements.

From its generation resources with MANEUVERING CAPABILITY, control areas create the following Interconnected Operations Services:

1. Spinning reserve for contingencies
2. Supplemental reserve for contingencies
3. Regulation

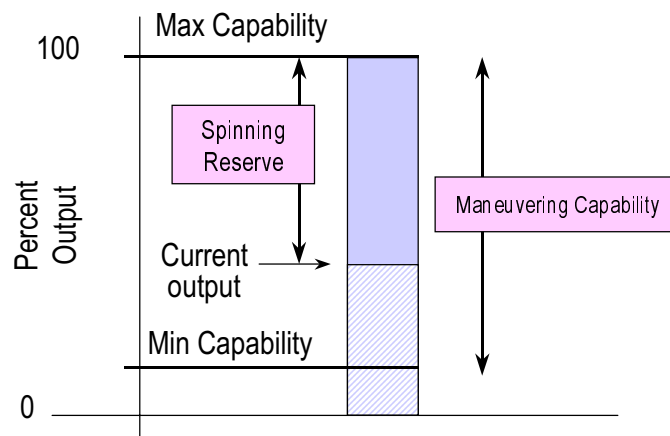


Figure 1 – Relationship between Spinning Reserve and Maneuvering Capability.

4. Load Following

Requirements

1. **Meeting Control Performance and Disturbance Control Standards.** Each CONTROL AREA shall maintain sufficient MANEUVERING CAPABILITY on its generation resources under governor control and load-frequency control to:
 - 1.1. **Provide frequency response.** Provide primary control (governor) response to both frequency increases and decreases.
 - 1.2. **Provide secondary control for Control Performance.** Provide secondary control (load-frequency control) response to keep its AREA CONTROL ERROR in compliance according to NERC's CONTROL PERFORMANCE STANDARD. (CPS) [**Policy 1.E. "Performance Standard."**]
 - 1.2.1. **Regulation service from remote areas.** LOAD-SERVING ENTITIES who arrange for REGULATION SERVICE from generation sources outside the HOST CONTROL AREA must reserve Firm Transmission service for the delivery of the Regulation Service.
 - 1.2.2. **Supplemental and overlap regulation service from remote areas.** CONTROL AREAS purchasing SUPPLEMENTAL or OVERLAP REGULATION service must reserve Firm Transmission service for the delivery of the Regulation Service to their CONTROL AREA boundary.
 - 1.3. **Provide secondary control for Disturbance Control.** Provide secondary control response to support its share of CONTINGENCY RESERVE (either alone or within its RESERVE SHARING GROUP) and comply with NERC's DISTURBANCE CONTROL STANDARD.
 - 1.3.1. **Disturbance Control Standard.** Each CONTROL AREA or RESERVE SHARING GROUP shall meet the Disturbance Control Standard (DCS) 100% of the time for REPORTABLE DISTURBANCES [**"Performance Standard Training Document," Section C.**]
 - 1.3.2. **Reserve Sharing Group.** Each RESERVE SHARING GROUP shall comply with the DCS as if it were a single CONTROL AREA. A RESERVE SHARING GROUP shall be considered in a DISTURBANCE condition any time a group member is in a DISTURBANCE condition and calls for reserves. Compliance may be demonstrated by either of the following two methods:
 - 1.3.2.1. **Group compliance to Disturbance Control Standard.** The RESERVE SHARING GROUP reviews group ACE (or equivalent) and demonstrates compliance.
 - 1.3.2.2. **Group member compliance to Disturbance Control Standard.** The RESERVE SHARING GROUP reviews each member's ACE in response to a call for reserves; to be in compliance each member's ACE must return to zero or to its respective pre-disturbance level within ten minutes of the start of the DISTURBANCE.
 - 1.3.3. **Jointly-owned generation with dynamic schedules.** CONTROL AREAs that share JOINTLY OWNED UNITS and incorporate DYNAMIC SCHEDULES or PSEUDO-TIES shall include only their share of the unit in their CONTINGENCY RESERVE calculations.

1.3.4. Jointly-owned generation with fixed schedules. CONTROL AREAs receiving their share of JOINTLY OWNED UNITS as fixed schedules should not include the jointly owned units' share(s) on which the schedules are based in their CONTINGENCY RESERVE calculations. The CONTROL AREA in which the jointly owned unit resides may include the CONTINGENCY RESERVES for its share of the unit.

1.3.5. SECONDARY RESERVES. Each control area must maintain sufficient SECONDARY RESERVES to restore its CONTINGENCY RESERVES as soon as practicable.

1.3.6. DCS compliance penalty. Each CONTROL AREA or RESERVE SHARING GROUP not satisfying the DISTURBANCE CONTROL STANDARD during a given calendar quarter shall increase its Operating Reserve Requirement for the calendar quarter (offset by a month) following the evaluation by an amount that is directly proportional to the CONTROL AREA'S or RESERVE SHARING GROUP'S non-compliance to the DISTURBANCE CONTROL STANDARD. (See the "Performance Standard Training Document," Section C.)

2. Contributing to operational security. Each Control Area shall operate its generation resources to contribute to the OPERATIONAL SECURITY of the INTERCONNECTION.

2.1. Failure of largest source. Each CONTROL AREA shall be able to withstand the failure of its largest generation resource without causing instability, uncontrolled separation from the INTERCONNECTION, or loading above emergency ratings or cascading outages of other equipment.

2.2. Failure of multiple sources. Each CONTROL AREA shall also examine multiple generation resource failures that are credible and, where practical, the control area shall operate to protect against instability, uncontrolled separation from the INTERCONNECTION, or cascading outages of other equipment.

2.3. Distribution of Contingency Reserves. Each CONTROL AREA shall distribute its CONTINGENCY RESERVE throughout its system so that these reserves can be used effectively whenever and wherever required.

2.4. Adequacy of Contingency Reserves. Each control area shall continually review the adequacy of its CONTINGENCY RESERVE to be able to comply with this Requirement.