NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL

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

Resources Subcommittee Meeting

October 26–28, 2005
Asheville, North Carolina

Minutes

A regular meeting of the North American Electric Reliability Council Resources Subcommittee was held on October 26–28, 2005 in Asheville, North Carolina. The meeting announcement, agenda, and attendance list are attached as **Exhibits A**, **B**, and **C**, respectively. Individual statements and minority opinions are affixed as **Exhibits D** and **E**. (There was one.)

Resources Subcommittee Chairman Terry Bilke presided. The secretary announced that a quorum was present.

Minutes of the Previous Meeting

The Resources Subcommittee approved the July 27–29, 2005 meeting minutes.

Resources Subcommittee Scope and Membership

The Resources Subcommittee reviewed and edited its draft scope, which is affixed as **Exhibit F**. All NERC regions have representation on the Resources Subcommittee at this time.

Action

The secretary will forward the draft scope to the Operating Committee for consideration and approval.

Resources Subcommittee Action Item List

The subcommittee reviewed and updated the action item list, which is affixed as **Exhibit G**.

Task Force Reports

Frequency Task Force — Chairman Raymond Vice

Balance Resources and Demand Draft Standard Field Test

The Frequency Task Force hosted a conference call to discuss the Balance Resources and Demand draft standard, Phase II field test. The conference call participants included the Resources Subcommittee and members of the Operating Reliability Subcommittee, the Reliability Coordinator Working Group (RCWG), Balance Resources and Demand Standard Drafting Team, and industry participants.

Raymond Vice and Doug Hils reported on the status of the Phase II field test. Discussion followed:

- There has not been a negative impact on the Eastern Interconnection frequency due to the Phase II, field test that began on July 6, 2005.

- The Balance Resources and Demand Standard Drafting Team has not received any negative calls or comments from any participating or non-participating Eastern Interconnection reliability coordinators or balancing authorities.
- The Balance Resources and Demand Standard Drafting Team requests small balancing authorities (2,500 MW or smaller) to volunteer to participate in the on-going Phase II field test.

Action — Next Balance Resources and Demand Standard Drafting Team Meeting

The Balance Resources and Demand Standard Drafting Team will host the next meeting/conference call on November 15, 2005 in Coconut Grove, Florida.

NERC Operating Standards Review

BAL-001, Real Power Balancing Control Performance

Control Criteria Task Force Chairman Alan Oneal led the discussion on the proposed changes to BAL-001, Real Power Balancing Control Performance draft standard. The subcommittee reviewed and enhanced the language, which is affixed as **Exhibit H**.

BAL-002, Disturbance Control Performance

Operating Reserves Task Force Chairman Larry Akens led the discussion on the proposed changes to BAL-002 Disturbance Control Performance draft standard, which is affixed as **Exhibit H**.

BAL-003, Frequency Response and Bias

Resources Subcommittee Chairman Terry Bilke led the discussion on the proposed changes to BAL-003, Frequency Response and Bias draft standard, which is affixed as **Exhibit H**.

BAL-004, Time Error Correction

Inadvertent Interchange Task Force Chairman Don Badley led the discussion on the proposed changes to BAL-004, Time Error Correction draft standard which is affixed as **Exhibit H**.

BAL-005, Automatic Generation Control

Frequency Task Force Chairman Raymond Vice led the discussion on the proposed changes to BAL-005, Automatic Generation Control, which is affixed as **Exhibit H**.

BAL-006, Inadvertent Interchange

Inadvertent Interchange Task Force Chairman Don Badley led the discussion on the proposed changes to BAL-006, Inadvertent Interchange draft standard, which is affixed as **Exhibit H**.

Action and Web cast

The Resources Subcommittee will continue drafting the proposed BAL-001 through BAL-006 standards revisions prior to submitting a SAR(s) with the drafts to the NERC standards process manager. With the assistance of the responsible lead persons (see above), the secretary will incorporate the recommended language into the drafts and distribute the pre-SAR standards to the subcommittee for review and comment, by November 11, 2005. The subcommittee will hold a conference call/Web cast on November 18, 2005 at 11 a.m., Eastern Standard Time, to finalize the proposed revisions.

Projects

ACE-Frequency Application, Project 2000-03

Project Manager Carlos Martinez reported that the Consortium for Electricity Reliability Technology Solutions (CERTS) is preparing an application revision to the ACE-Frequency software, which will be distributed as Release 4. The subcommittee discussed the ACE-Frequency software application, endorsed the on-going ACE-Frequency software application, and endorses the proposed funding estimates. (See motion below.)

AIE Monitoring Application, Project 2000-04

The Resources Subcommittee discussed the AIE Monitoring Application, Project 2000-04 and the five-year cost projections. The subcommittee endorses the project; see the motion below and the scope which is affixed as **Exhibit I**.

CPS1 & BAAL Monitoring Application, Project 2001-38

The Resources Subcommittee discussed the CPS1 & BAAL Monitoring Application, Project 2001-38 and the five-year cost projections. The subcommittee endorses the project; see the motion below and the scope which is affixed as **Exhibit J**.

Frequency-Phasor Monitoring Application, Project 2005-X

The Resources Subcommittee discussed the Frequency-Phasor Monitoring Application, Project 2005-X and the five year on-going cost projection. The subcommittee endorses the project; see the motion below and the scope which is affixed as **Exhibit K**.

Inadvertent Interchange Application (SPP Inadvertent Tool Migration), Project 2001-37

The Resources Subcommittee discussed the Inadvertent Interchange Application, Project 2001-37 five year on-going cost projection. This is an on-going software application used to identify inadvertent interchange balances/disputes. The subcommittee endorsed the on-going software application and the proposed funding estimates. (See the motion below.)

*AIE Monitoring Application Project; CPS1 & BAAL Monitoring Project; and Frequency-Phasor Monitoring Applications Project **Motion***

The Resources Subcommittee discussed the scope and five-year budget projections for the AIE Monitoring Application, Project 2000-04; CPS1 & BAAL Monitoring Application, Project 2001-38; and Frequency-Phasor Monitoring Application, Project 2005-X. Each project was discussed individually but the following motion covered all three projects.

Raymond Vice moved: The Resources Subcommittee endorses the AIE Application Project; CPS1 & BAAL Monitoring Application Project; and the Frequency – Phasor Monitoring Application Project to proceed and recommends the Operating Committee endorse and approve these projects. The motion was approved.

AIE Data Collection Protocol Motion

The Resources Subcommittee discussed the protocol for collecting hourly data to satisfy the AIE monitoring application project and the possibility of future hourly inadvertent interchange data collection. The subcommittee prefers that the Data Exchange Working Group determine the best method and protocol for collecting the respective data.

Raymond Vice moved: The Resources Subcommittee does not have the expertise to set software protocols. The subcommittee recommends the Data Exchange Working Group (DEWG) work with the appropriate vendor(s) to define a communications protocol for exchanging the appropriate data. The Resources Subcommittee wished to be kept informed of the direct and indirect costs, benefits, and limitations of the selected protocol by the DEWG. The motion was approved.

On-going ACE-Frequency and Inadvertent Interchange Applications Budgets Motion

Raymond Vice moved: The Resources Subcommittee endorses the on-going ACE-Frequency Application and the Inadvertent Interchange Application proposed five-year budgets and recommends that the Operating Committee endorse and approve the proposed budgets. The Resources Subcommittee recommends the NERC staff monitor the on-going expenditures to ensure that they are properly accounted for and minimized to the extent possible. The motion was approved.

Resources Subcommittee Recommendations to the NERC Operating Committee

- The three new projects (AIE Monitoring Application, Project 2000-04; CPS1 & BAAL Monitoring Application, Project 2001-38; and Frequency-Phasor Monitoring Application, Project 2005-X) were discussed and endorsed by the Operating Committee at its September 2005 meeting. The Resources Subcommittee recommends that the Operating Committee endorse and approve the projects' scopes and respective funding reflected in the motions above. Resources Subcommittee Chairman Terry Bilke will attend the December 2005 Operating Committee meeting to discuss the projects with the committee.
- The Resources Subcommittee endorses the two on-going operations software applications' (ACE-Frequency Application; and Inadvertent Interchange Application) five-year budgets and recommends the Operating Committee endorse and approve the proposed budgets. Resources Subcommittee Chairman Terry Bilke will attend the December 2005 Operating Committee meeting to discuss the two on-going operations applications with the committee.
- The Resources Subcommittee recommends that the Operating Committee assign the AIE data submittal protocol development to the Data Exchange Working Group (DEWG). The subcommittee believes the DEWG has the expertise to develop the proper protocol for the application(s).

Performance Monitoring

CPS1 Review

The Resources Subcommittee reviewed the monthly and 12-month rolling average CPS1 data for trends and violations. There are no current CPS1 violations. However, there are balancing authorities that have monthly values that are below 100%.

Note: the Resources Subcommittee did not have time to discuss the following three items. The subcommittee members agreed to review these after the meeting and report any significant observations;

- Third-quarter CPS2 data
- Third-quarter DCS data
- Third-quarter frequency trends.

Time Error Corrections

The following interconnection time error corrections from January 1, through September 30, 2005 were reported:

	Fast TEC	**Slow TEC**	**Total TEC**
Eastern Interconnection	**159**	**0**	**159**
Western Interconnection	**28**	**27**	**55**
ERCOT	**26**	**13**	**39**

Dates and Locations of Future Meetings

1. February 8–10, 2006 Scottsdale, AZ
2. May 3–5, 2006 Baltimore, MD
3. September 20–22, 2006 Québec City, QU
4. November 15–17, 2006 Fort Lauderdale, FL

Respectfully submitted,

Tom Vandervort

Thomas J. Vandervort
Resources Subcommittee Secretary

Exhibit A

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL

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

Resources Subcommittee

Wednesday, October 26, 2005 — 8 a.m. to 5 p.m.
Thursday, October 27, 2005 — 8 a.m. to 5 p.m.
Friday, October 28, 2005 — 8 a.m. to noon

Meeting Logistics and Registration Form

Hotel	Haywood Park Hotel 1 Battery Park Avenue Asheville, NC 28801
Phone and fax	Ph: 828-252-2522 ☎ Fax: 828-253-0481
Room rate	$175 single/double occupancy
Block name	NERC-RS
Room block	Nights of **October 25–27, 2005**
Reservation cut-off date	**October 3, 2005** (NOTE: After this date, the hotel will release this block of rooms and only accept reservations on a space-available basis.)
Check-in and check-out times	Check in: 3 p.m. Check out: noon
Transportation	The hotel is located about 25 minutes from the **Asheville Regional Airport** • Shuttle service is available at baggage claim. Cost: Approximately $25–30 • Taxi: Approximately $25–30
Hotel reservation instructions	You must mention the "NERC/North American Electric Reliability Council-RS" meeting to ensure that the hotel credits your reservation to the NERC room block and to get the preferred rate. *The hotel may charge NERC a penalty if the total rooms blocked for this event are not picked up.* Also, if you use a travel agency for your travel plans, please make sure the agency mentions NERC.
Attire	Business casual.

Please type or print.

Name:		
Title:		
Company:		
Telephone:		
Email:		
Proxy: ☐	**Guest:** ☐	**Member for whom you are a proxy:**
Attending: ☐		**Not Attending:** ☐

Exhibit B

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL

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

Resources Subcommittee Meeting

Wednesday, October 26, 2005 — 8 a.m.–5 p.m.
Thursday, October 27, 2005 — 8 a.m.–5 p.m.
Friday, October 28, 2005 — 8 a.m.–noon

Haywood Park Hotel
1 Battery Park Avenue
Asheville, NC 28801
Phone: 828-252-2522 ☎ Fax: 828-253-0481

Agenda

Frequency Task Force Conference Call
Balance Resources and Demand Standard Field Test Discussion

Wednesday, October 26, 2005
Conference Call Time: 1–3:30 p.m. EDST (10 a.m.-12:30 p.m. PDST)
Phone Number: (732) 694-2061
Access Code: 1108102605#

1. Administrative

a. Membership and Guests — Chair
b. Introductions — Chair
c. Organization, Roster, and Survey Contacts List — Secretary
d. Arrangements — Secretary
e. Approval of July 27–29, 2005, Meeting Minutes — Chair
f. Approval of Agenda — Chair
g. Procedures
   i) Parliamentary Procedures — Chair
   ii) Antitrust Compliance Guidelines — Chair
h. Resources Subcommittee Scope — Chair
i. Resources Subcommittee Action Items List — Chair

2. Task Force Reports

a. Control Criteria Task Force — Alan Oneal
b. Frequency Task Force — Raymond Vice
c. Inadvertent Interchange Task Force — Don Badley
d. Operating Reserves Task Force — Larry Akens

3. Compliance

a. Compliance and Certification Managers Committee Liaisons — Bill Herbsleb, Raymond Vice
b. Update on MISO ACE Diversity Interchange (ADI) Program — Raymond Vice, Terry Bilke

4. NERC Reliability Standards

a. Standard BAL-001-0, Real Power Balancing Control Performance — Alan Oneal
b. Standard BAL-002-0, Operating Reserves — Larry Akens
c. Standard BAL-003-0, Frequency Response and Bias — Terry Bilke
   i) Frequency Response Standard SAR — Terry Bilke
d. Standard BAL-004-0, Time Error Correction — Don Badley
e. Standard BAL-005-0, Automatic Generation Control — Raymond Vice
f. Standard BAL-006-0, Inadvertent Interchange – Don Badley
g. Reference Document – Performance Standards Reference Document — Alan Oneal
h. Training Document – Area Interchange Error Survey Training Document — Don Badley
i. Training Document – Frequency Response Characteristic Survey — Raymond Vice
j. Training Document – Inadvertent Interchange Accounting Training Document — Don Badley
k. Balance Resources and Demand Draft Standard Update — Raymond Vice

5. NERC Active Resources Subcommittee Projects — Status

a. ACE-Frequency Application Project (Project 2000-03) — Carlos Martinez
b. AIE Monitoring Application Project (Project 2000-4) — Carlos Martinez
c. CPS1 & BAAL Monitoring Application Project (Project 2001-38) — Carlos Martinez
d. Frequency-Phasor Monitoring Application Project (Project 2005-X) — Terry Bilke, Carlos Martinez
e. DOE Eastern Interconnection Phasor Project (EIPP) — Terry Bilke, Carlos Martinez
f. Inadvertent Interchange Application Project (SPP inadvertent interchange tool migration) (Project 2001-37) — Carlos Martinez
g. Data Quality — Carlos Martinez

6. Frequency Performance

a. Western Interconnection Frequency Trends
b. Eastern Interconnection Frequency Trends
c. ERCOT Frequency Trends
d. CPS1 and CPS2 Data Trends
e. DCS Data Trends
f. Inadvertent Interchange Balances — Joe Emde, Don Badley, Terry Bilke
g. Responsibility for Initiating AIE Surveys — Terry Bilke, Raymond Vice
h. High Frequency Issue — Terry Bilke, Raymond Vice, Larry Akens
   i) RS Proposed Frequency Monitoring and Response Process for the Eastern Interconnection — Terry Bilke, Raymond Vice, Larry Akens
   ii) Decline of the Eastern Interconnection Frequency Response — Raymond Vice
   iii) Eastern Interconnection Frequency Excursions — Terry Bilke, Raymond Vice, Larry Akens, Carlos Martinez

7. Time Error

a. Eastern Interconnection — Bill Herbsleb
b. Western Interconnection — Don Badley
c. ERCOT Interconnection — Sydney Niemeyer

8. Dynamic Transfer Catalog

9. Future Meetings

a. February 8–10, 2006 — Scottsdale, AZ
b. May 3–5, 2006 v Baltimore, MD
c. September 20–22, 2006 — Québec City, QU
d. November 15–17, 2006 — Ft. Lauderdale, FL

Exhibit C

Resources Subcommittee Meeting
October 26–28, 2005
Asheville, North Carolina

RS Meeting Attendance Sheet	
Resources Subcommittee Member/Guest	**Organization**
Terry Bilke (Chairman)	MISO
Larry Akens	TVA/SERC
Don Badley	NWPP
Gerry Beckerle	Ameren
Bill Herbsleb	PJM
Sydney Niemeyer	Texas Genco, LP
Alan Oneal	MidAmerican Energy
Mike Potishnak	ISO-NE
Robert Rhodes (for Carl Monroe)	SPP
John Swez	Cinergy
John Tolo	Tucson Electric Power
Raymond Vice	Southern Company
Tom Vandervort	NERC
Carlos Martinez	CERTS/EPG
Robert Blohm	Economist/Consultant

Exhibit D

Individual Statements
Resources Subcommittee Meeting
October 26–28, 2005

Michael J. Potishnak — ISO New England, Inc.

CPS2 is part of BAL-001 now, and it is inappropriate to move it into BAL-002. BAL-001 addresses issues for which regulating reserve is deployed. BAL-002 addresses issues related to the deployment of contingency reserve, and thus inappropriate to move CPS2 into BAL-002. If or when the drafted balancing standard replaces CPS2, it should be deleted at that time.

Exhibit E

Minority Opinions
Resources Subcommittee Meeting
October 26–28, 2005

There were none.

Exhibit F

Resources Subcommittee Scope

Draft

Purpose

The NERC Operating Committee delegates to the Resources Subcommittee the responsibility to be the initial interface with the balancing authority function, the generator operator function, and the generator owner function, to initiate resolution of balancing authority-related operations issues and the technical interpretation of the balancing authority-related operating reliability standards.

Definition

Balancing authority, generator operator, and generator owner are defined in the Glossary of Terms.

Scope

The Resources Subcommittee shall be the specific subcommittee that the Operating Committee relies on to address balancing authority-related operations issues and technical interpretation of those operating reliability standards.

Reliability Responsibilities

a. Support the Operating Committee by addressing technical issues primarily related to the balancing authority, generator operator, generator owner, and reliability coordinator functions.
b. Assess the effectiveness and impacts of balancing authority-related operations reliability standards.
c. Identify the need for new balancing authority reliability standards or revisions to standards and initiate standards action by submitting SARs.
d. Assist the standards process by providing expert resources in support of the development of balancing authority reliability SARs and standards.
e. Assist the standards process by providing a forum for balancing authority reliability standards discussion, sharing of views, and informed debate.
f. Review balancing authority standards to facilitate developing reference documents and performing other activities.
g. Provide input and recommendations on the training issues concerning the balancing authority, generator operator, and generator owner.
h. Provide technical assistance to monitor, evaluate, and process frequency and generation-load balancing data.
i. Assist in the development of real-time and post-analysis tools to enhance and measure the reliability of the bulk power system.
j. Independently evaluate proposed and existing NAESB business practices for impacts on frequency or load-generation balance control performance.
k. Investigate compliance issues as requested by NERC compliance group(s).
l. Define analytical methodologies and data retention to be used by the interconnections for data analyses provided to the RS.
m. Investigate incidents as requested by the operating committee. This may include:

- Load-generation balancing
- Interchange deployment
- Inadvertent Interchange accounting and payback
- Control performance
- Automatic generation control
- Time error correction
- Operating reserve
- Frequency response

Resources Subcommittee NERC Operating Reliability Standards Assignment

Refer to Resources Subcommittee balancing authority related standards found on the NERC RS Web site under "related documents."

Reporting

The Resources Subcommittee reports to the NERC Operating Committee and shall communicate with the Planning Committee, designated North American Energy Standards Board working groups, other Operating Committee subcommittees, and other groups as necessary to address relevant balancing authority-related operations concerns.

Membership

Voting Members

a. Each regional reliability organization will provide at least one member. The regions will select those members based on their expertise in balancing authority operations.
b. Each Interconnection as well as Canada must be represented, and the subcommittee chairman, working with the NERC staff, will ask for additional members from the regional reliability councils as necessary to fulfill these requirements.
c. The subcommittee will recommend additional members as needed for their expertise.

Member Expectations

a. NERC expects Resources Subcommittee members to participate in all meetings and conference call discussions and be willing to help draft reports, proposals, standards authorization requests, and standards.
b. The Resources Subcommittee may request a region, an ISO/RTO, or other industry organization to nominate an individual that meets the above criteria as a replacement for its member that misses three consecutive meetings without sending a proxy.

Observers

Subcommittee meetings are open; however, observers must register to attend.

Officers

The Operating Committee chairman selects the chairman and vice chairman. The chairman does not represent a region. Both officers may vote.

Meeting Procedures

- Quorum: 50% of subcommittee members or proxies eligible to vote
- All other procedures follow the "Organization and Procedures Manual for the NERC Standing Committees."
- NERC will supply a facilitator for subcommittee activities.
- Liaisons from NAESB, CEA, DOE, and others will be invited as required.

Subgroups

The Resources Subcommittee may form working groups, task groups, and task forces as needed to assist the subcommittee in carrying out standing or ad hoc assignments. Task group chairs (or delegates) are expected to attend the regular subcommittee meetings to report on assignments.

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL

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

DRAFT

Resources Subcommittee NERC Operating Reliability Standards Assignment

The NERC Operating Committee delegated to the Resources Subcommittee the responsibility to be the initial interface with the balancing authority function, the generator operator function, and the generator owner function, to initiate resolution of balancing authority-related operations issues and technical interpretation of the balancing authority-related operations reliability standards. For additional information the resources subcommittee's reliability responsibilities refer to the resources subcommittee scope

The balancing authority-related operations reliability standards and reference documents that the resources subcommittee will have primary custodianship over are:

a. Standard BAL-001, Real Power Balancing Control Performance
b. Standard BAL-002, Disturbance Control Performance
c. Standard BAL-003, Frequency Response and Bias
d. Standard BAL-004, Time Error Correction
e. Standard BAL-005, Automatic Generation Control
f. Standard BAL-006, Inadvertent Interchange
g. Reference Document — Performance Standards Reference Document
h. Training Document — Area Interchange Error Survey Training Document
i. Training Document — Frequency Response Characteristic Survey
j. Training Document — Inadvertent Interchange Accounting Training Document

Other standards that the resources subcommittee has partial requirements or responsibilities within are:

k. Standard INT-001, Interchange Transaction Tagging
l. Standard INT-003, Interchange Transaction Implementation
m. Standard TOP-001, Reliability Responsibilities and Authorities
n. Standard TOP-005, Operational Reliability Information
o. Standard TOP-006, Monitoring System Conditions
p. Standard EOP-001, Load Shedding Plans
q. Standard EOP-002, Capacity and Energy Emergencies
r. Standard EOP-008, Plans for Loss of Control Center Functionality
s. Standard COM-001, Telecommunications
t. Standard PER-001, Operating Personnel Responsibility and Authority
u. Standard IRO-005, Reliability Coordination — Current Day Operations

Exhibit G

Resources Subcommittee

October 27, 2005 Meeting

Open Action Item List

Action Figure	Subject	Action Item/Assignment	Due Date	Completion Date
Carl Monroe	SPP Inadvertent Tool Use by FRCC	The issue raised within this action item is to try to get the FRCC BAs to use the new NERC Inadvertent Interchange tool (migrated SPP Inadvertent Interchange tool). 102705, The RS's proposed BAL revisions need to include a requirement for all BAs to submit required hourly data to populate hourly AIE surveys which can be used ot populate the inadvertent interchange software application. See the proposed BAL-006 standards revisions in this meeting's agenda.	020806	
Carl Monroe	FRCC BAs CERTS ACE-Frequency Data	072805, Carl to contact FRCC Regional Manager to request data be submitted as BA data instead of regional data to NERC to populate the CERTS ACE-Frequency displays. TV to draft a letter for Carl. Letter sent to Carl for his review on 080205. 081605, Letter was sent from Carl to Linda Campbell, FRCC Manager, requesting FRCC's BAs submit data to the NERC ACE-Frequency software application. 102705, The RS's proposed BAL revisions need to include a requirement for all BAs to submit required hourly data to populate hourly AIE surveys. See the proposed BAL standards revisions in this meeting's agenda. 110205, TV asked Carl if he received a response from FRCC.	020806	
Tom Vandervort	Draft SAR for BAL Standards	102805, TV to draft a SAR to capture significant changes to BAL-001 through BAL-006 RS proposed revisions.	111805	
Tom Vandervort	Set up conference call/web cast	102805, TV to set up web cast / conference call for November 18, at 11:00 am to discuss proposed standard revision comments and to finalize the proposed standards revisions and to review the accompanying SAR.	111005	
Don Badley	AIE Software – Functionality System Review	10/29/04, Don Badley to process RS Members Confidentiality Forms (work with Carlos as necessary) to allow them to review the CERTS AIE – in order to Test Functionality of the System • Reconciled Hourly AIE Data • Reconciled Monthly Inadvertent Data Don to attain addresses, phone numbers, e-mail addresses from the agenda item 1:	020806	

Action Figure	Subject	Action Item/Assignment	Due Date	Completion Date
		Frequency Task Force Members to evaluate the AIE System: Don Badley Raymond Vice Bart McMannus Don to process WECC confidentiality agreement for Bart. John Tolo Don to process WECC confidentiality agreement for John. Terry Bilke Don McInnis Mike Potishnak Tom Vandervort Brian Nolan 102805, CERTS – RS Frequency Task Force review team had problems accessing the CERTS AIE software and data. CERTS is addressing the problem. The deadline was pushed back to give the team time to analyze the software and data. Carlos to supply data for team to analyze.		
Don Badley and IITF	BAL-004, BAL-006, Ref Docs, Training Docs	BAL-004 & 006 RS proposed revisions in progress. • Review V0 Standards to ensure they are “safe and effective” • Recommend moving sections within V0 to a Ref Doc • Recommend improvements to the V0 via a SAR • Recommend deletions of sections of V0 • Recommend forwarding sections of V0 to NAESB • Start with V0 Standards, Ref Docs, Training Docs Standard BAL-004-0, Time Error Correction, Version 0 Standard BAL-006-0, Inadvertent Interchange, Version 0 Training Document – Area Interchange Error Survey Training Document	020806	

Action Figure	Subject	Action Item/Assignment	Due Date	Completion Date
		Training Document – Inadvertent Interchange Accounting Training Document 102805, RS is finalizing its in the process of drafting the BAL-001 through BAL-006 proposed revisions. An accompanying SAR will be forwarded with the BAL drafts to the NERC standards process manager. RS will finalize the proposed BAL standards revisions on Nov 18, 2005.		
Don Badley	Review Freq Monitoring Guide (Triggers and Actions Guide)	072905, RS reviewed and revised the RS Frequency Monitoring and Response Process (Triggers and Action Guide) for the Eastern Interconnection. 102705, Don presented it to WECC and it will be addressed by the WECC Performance Criteria WG in the next couple of weeks. 020805, Don to status the WECC effort to establish a similar Frequency Monitoring Guide.	020806	
Terry Bilke	BAL-003, Ref Docs, Training Docs	BAL-003 RS proposed revision in progress. • Review V0 Standards to ensure they are "safe and effective" • Recommend moving sections within V0 to a Ref Doc • Recommend improvements to the V0 via a SAR • Recommend deletions of sections of V0 • Recommend forwarding sections of V0 to NAESB • Start with V0 Standards, Ref Docs, Training Docs Standard BAL-003-0, Frequency Response and Bias, Version 0 Pay close attention to the variable bias calculation Training Document – Frequency Response Characteristic Survey Training Document 050505, On-going activity 102805, RS is finalizing its in the process of drafting the BAL-001 through BAL-006 proposed revisions. An accompanying SAR will be forwarded with the BAL drafts to the NERC standards process manager. RS will finalize the proposed BAL standards revisions on Nov 18, 2005.	020806	
Raymond Vice and Freq TF	Combustion Turbine Governor Response	050505, The Combustion Turbine Governor Response issue only occurs when gas turbines are operating at maximum output limited by blade temperature as indicated by exhaust gas temperature and only limits response to low frequency deviations. It is not clear what percentage of gas turbines operate in this mode at any given time. In addition, the mass flow of air through the compressor of a gas turbine varies geometrically with frequency (speed of the compressor). This may reduce the ability	020806	

Action Figure	Subject	Action Item/Assignment	Due Date	Completion Date
		of the turbine to respond to frequency deviation. The Frequency Task Force will continue to investigate these issues and determine if a NERC Reliability Standard requirement(s) is necessary. 102705, TF proposes changes to the "BAL" standards for RS concurrence and then submittal of a SAR(s) to the NERC standards process manager. See meeting agenda. The problem is that most BA combustion turbine generators operate such that there are no reserves to allow for governor response. There simply is no room for a higher response. Raymond to resurrect his white paper and create combustion turbine bullet points in order to allow John Undrill to address the RS issues.		
Larry Akens and ORTF	BAL-002, Ref Docs, Training Docs	BAL-002 RS proposed revision in progress. • Review V0 Standards to ensure they are "safe and effective" • Recommend moving sections within V0 to a Ref Doc • Recommend improvements to the V0 via a SAR • Recommend deletions of sections of V0 • Recommend forwarding sections of V0 to NAESB • Start with V0 Standards, Ref Docs, Training Docs Standard BAL-002-0, Disturbance Control Performance, Version 0 102805, RS is finalizing its in the process of drafting the BAL-001 through BAL-006 proposed revisions. An accompanying SAR will be forwarded with the BAL drafts to the NERC standards process manager. RS will finalize the proposed BAL standards revisions on Nov 18, 2005.	020806	
Larry Akens and ORTF; and Don Badley	WECC DCS Consideration	050505, The Operating Reserve Task Force will review the WECC DCS grace period of 60 minutes and consider incorporating the language into a SAR during the RS standards review process. Mike Potishnak to attain the details from Don Badley. 072805, Don Badley to send the WECC DCS contingency recovery criteria and details to Larry for BAL-002, Disturbance Control Performance, consideration. In progress. 102805, RS is finalizing its in the process of drafting the BAL-001 through BAL-006 proposed revisions. An accompanying SAR will be forwarded with the BAL drafts to the NERC standards process manager. RS will finalize the proposed BAL standards revisions on Nov 18, 2005.	020806	
Raymond Vice and	BAL-005, Ref Docs, Training Docs	BAL-005 RS proposed revision in progress. • Review V0 Standards to ensure they are "safe and effective"	020806	

Action Figure	Subject	Action Item/Assignment	Due Date	Completion Date
Frequency TF		• Recommend moving sections within V0 to a Ref Doc • Recommend improvements to the V0 via a SAR • Recommend deletions of sections of V0 • Recommend forwarding sections of V0 to NAESB • Start with V0 Standards, Ref Docs, Training Docs Standard BAL-005-0, Automatic Generation Control, Version 0 102805, RS is finalizing its in the process of drafting the BAL-001 through BAL-006 proposed revisions. An accompanying SAR will be forwarded with the BAL drafts to the NERC standards process manager. RS will finalize the proposed BAL standards revisions on Nov 18, 2005.		
Raymond Vice and Freq TF	Frequency Issues 2005, White Paper	102805, The RS did not have time to review and discuss Raymond's Frequency Issues 2005, white paper. The Frequency TF will review the concerns identified in the white paper and propose actions or discussion points for the RS to consider. 020806, ?	020806	
Sydney Niemeyer	Review Freq Monitoring Guide (Triggers and Actions Guide)	072905, RS reviewed and revised the RS Frequency Monitoring and Response Process (Triggers and Action Guide) for the Eastern Interconnection. 102705, Sydney is requested to present the guide to ERCOT in the next couple of weeks. 020805, Sydney to status the ERCOT effort to establish a similar Frequency Monitoring Guide.	020806	
Carlos Martinez	AIE Project (Project 2000-4)	050505, Carlos to send AIE Monitoring Project specifications, approvals, background information to Brian Nolan, NERC Projects Manager. This information and documentation is necessary for the project paper trail. 102705, RS made a motion recommending the OC endorse the Hourly AIE Monitoring Application Project Scope and projected five-year budget. Terry to present the project to the OC in December, 2005; Brian to support Terry with the budget presentation. 020806, Terry to recap OC discussion and presentation.	020806	
Carlos Martinez	CPS1 & BAAL Displays Application (Project 2001-38)	050505, Carlos to send CPS1 and CPS2 Monitoring Application Project specifications, approvals, background information to Brian Nolan, NERC Projects Manager. This information and documentation is necessary for the project paper trail. 102705, RS made a motion recommending the OC endorse the CPS1 & BAAL Monitoring Application Project Scope and projected five-year budget. Terry to	020806	

Action Figure	Subject	Action Item/Assignment	Due Date	Completion Date
		present the project to the OC in December, 2005; Brian to support Terry with the budget presentation. 020806, Terry to recap OC discussion and presentation.		
Carlos Martinez and Terry Bilke	Phasor - Freq Analysis Project Tools	050505, Terry Bilke made a motion for the Resources Subcommittee to develop tools and methodologies for analysis of Eastern Interconnection frequency data supplied from EIPP and based on Phasor measurement technology. These methods and tools will be designed to be compatible with the other Interconnections. The motion passed. 102705, RS made a motion recommending the OC endorse the Frequency-Phasor Monitoring Application Project Scope and projected five-year budget. Terry to present the project to the OC in December, 2005; Brian to support Terry with the budget presentation. 020806, Terry to recap OC discussion and presentation.	020806	

A. Introduction

1. **Title**: **Real Power Balancing Control Performance**
2. **Number**: BAL-001-1 – RS Proposed
3. **Purpose**: To maintain Interconnection steady-state frequency within defined limits by balancing real power demand and supply in real-time.
4. **Applicability**:
   - Balancing Authorities
5. **Proposed Effective Date:** Completion of Formal Standards Authorization Process

B. Requirements

R1. Each balancing authority shall perform real-time monitoring of its area control error (ACE) and its interconnection's frequency.

R2. Each balancing authority shall restrict its time-averaged adverse reliability impact on interconnection frequency within the bounds specified by control performance measure-1 (CPM1).

- Each balancing authority shall report its CPM1 performance to its compliance monitor each month.

R3. The ACE equation shall not include any balancing authority's control functions that are used for interchange operations. Control adjustments for unilateral inadvertent payback or other operational adjustment shall not be included in the ACE equation.

R4. Each balancing authority that participates in the following activities affecting the ACE and CPM equations shall comply with the requirements found in Standard BAL-005, Automatic Generation Control:

- Supplemental Regulation Service
- Overlap Regulation Service
- Dynamic Schedules
- Pseudo-ties

C. Measures

M1. Each balancing authority shall demonstrate real-time monitoring of ACE and interconnection frequency against associated limits.

M2. Compliance Performance Measure-1 (CPM1): Each balancing authority shall operate such that, on a rolling 12-month basis, the average of the clock-minute averages of the balancing authority's area control error (ACE) divided by 10B (B is the clock-minute average of the balancing authority area frequency bias) times the corresponding clock-minute averages of the interconnection's frequency error is less than a specific limit, ε_1^2(epsilon 1 squared).

$$AVG_{Period}\left[\left(\frac{ACE_i}{-10B_i}\right)_1 * \Delta F_1\right] \le \in_1^2 \; or \; \frac{AVG_{Period}\left[\left(\frac{ACE_i}{-10B_i}\right)_1 * \Delta F_1\right]}{\in_1^2} \le 1$$

- B (MW/0.1 Hz), is the frequency bias setting for the balancing authority. The constant factor 10 converts the frequency setting to MW/Hz.
- ε_1^2 (epsilon 1 squared), is a constant derived from a targeted frequency bound (ε_1, separately calculated for each Interconnection) that is reviewed and set as necessary by the NERC operating committee.
- ΔF_1 (Hz), is the corresponding clock-minute averages of the interconnection's frequency error.

The equation for ACE is:

$ACE = (NI_A - NI_S) - 10B\ (F_A - F_S) - I_{ME}$

where:

- NI_A (MW), Net Actual Interchange, is the algebraic sum of actual flows on all tie lines.

NI_S (MW), Net Scheduled Interchange, is the algebraic sum of scheduled flows on all tie lines. Within an interconnection, the sum of all scheduled flows among all balancing authorities must be zero at all times.

- B (MW/0.1 Hz), Frequency Bias Setting for the balancing authority. The constant factor 10 converts the frequency setting to MW/Hz.
- F_A (Hz), is the actual frequency. Within an alternating current interconnection operating synchronously, observed steady-state frequency should be the same at all locations. Periodic checks should be made to assure this..
- F_S (Hz) is the scheduled frequency. F_S is normally 60 Hz but may be offset to effect manual or automatic time error corrections. Within an alternating current interconnection operating synchronously, scheduled frequency must be the same for all balancing authorities at all times.
- I_{ME} (MW) is the meter error correction factor typically estimated from the difference between the integrated hourly average of the net tie line flows (NI_A) and the hourly net interchange demand measurement (megawatt-hour). This term should normally be very small or zero.

M3. Each balancing authority shall achieve, as a minimum (CPM1) compliance of 100%.

CPM1 is calculated by converting a compliance ratio to a compliance percentage as follows:

CPM1 = (2 - CF) * 100%

The frequency-related compliance factor, CF, is a ratio of all one-minute compliance parameters accumulated over 12 months divided by the target frequency bound:

$$CF = \frac{CF_{12-month}}{(\in_1)^2}$$

where: ε_1 is defined in Requirement R1.

The rating index $CF_{12\text{-month}}$ is derived from 12 months of data. The basic unit of data comes from one-minute averages of ACE, frequency error and frequency bias settings.

A clock-minute average is the average of the reporting balancing authority's valid measured variable (i.e., for ACE and for frequency error) for each sampling cycle during a given clock-minute.

$$\left(\frac{ACE}{-10B}\right)_{\text{clock-minute}} = \frac{\left(\frac{\sum ACE_{\text{sampling cycles in clock-minute}}}{n_{\text{sampling cycles in clock-minute}}}\right)}{\text{-10B}}$$

$$\Delta F_{\text{clock-minute}} = \frac{\sum \Delta F_{\text{sampling cycles in clock-minute}}}{n_{\text{sampling cycles in clock-minute}}}$$

The balancing authority's clock-minute compliance factor (CF) becomes:

$$CF_{\text{clock-minute}} = \left[\left(\frac{ACE}{-10B}\right)_{\text{clock-minute}} * \Delta F_{\text{clock-minute}}\right]$$

The reporting balancing authority shall be able to recalculate and store each of the respective clock-hour averages (CF clock-hour average-month) as well as the respective number of samples for each of the twenty-four (24) hours (one for each clock-hour, i.e., hour-ending (HE) 0100, HE 0200, ..., HE 2400).

$$\text{CF}_{\text{clock-hour average-month}} = \frac{\sum_{\text{days-in-month}} [(\text{CF}_{\text{clock-hour}})(n_{\text{one-minute samples in clock-hour}})]}{\sum_{\text{days-in month}} [n_{\text{one-minute samples in clock-hour}}]}$$

$$\text{CF}_{\text{month}} = \frac{\sum_{\text{hours-in-day}} [(\text{CF}_{\text{clock-hour average-month}})(n_{\text{one-minute samples in clock-hour averages}})]}{\sum_{\text{hours-in day}} [n_{\text{one-minute samples in clock-hour averages}}]}$$

The 12-month compliance factor becomes:

$$\text{CF}_{\text{12-month}} = \frac{\sum_{\text{i=1}}^{12} (CF_{\text{month-i}})(n_{(\text{one-minute samples in month})-\text{i}})]}{\sum_{\text{i=1}}^{12} [n_{(\text{one-minute samples in month})\text{-i}}]}$$

In order to ensure that the average ACE and frequency deviation calculated for any one-minute interval is representative of that one-minute interval, it is necessary that at least 50% of both ACE and frequency deviation sample pairs during that one-minute interval be present. Should a sustained interruption in the recording of ACE or frequency deviation due to loss of telemetering or computer unavailability result in a one-minute interval not containing at least 50% of samples pairs of ACE and frequency deviation, that one-minute interval shall be excluded from the calculation of CPM1.

M4. Each balancing authority shall calculate and report the monthly average of its one-minute CPM1 to its compliance monitor no later than the 20th of each month for the prior month's data.

M5. Each balancing authority shall be able to demonstrate that its ACE equation does not include any control functions that are used for interchange operations.

D. Compliance

1. Compliance Monitoring Process

- Compliance Monitoring Responsibility

  Regional Reliability Organization.

- **Compliance Monitoring Period and Reset Timeframe**

  One calendar month.

- **Data Retention**

  The data that supports the calculation of CPM1 (Attachment 1-BAL-001-1) are to be retained in electronic form for at least a one-year period. If the CPM1 data for a balancing authority area are undergoing a review to address a question that has been raised regarding the data, the data are to be saved beyond the normal retention period until the question is formally resolved. Each balancing authority shall retain for at least a full year the values of: one-minute average ACE (ACE_i), one-minute average frequency error, and, if using variable bias, one-minute average frequency bias.

- **Additional Compliance Information**

  None.

2. Levels of Non-Compliance – CPM1

- **Level 1:** The balancing authority area's value of CPM1 is less than 100% but greater than or equal to 95%.
- **Level 2:** The balancing authority area's value of CPM1 is less than 95% but greater than or equal to 90%.
- **Level 3:** The balancing authority area's value of CPM1 is less than 90% but greater than or equal to 85%.
- **Level 4:** The balancing authority area's value of CPM1 is less than 85%.
-

E. Regional Differences

1. None

Version History

Version	Date	Action	Change Tracking

Attachment 1-BAL-001-1
CPM1 Data

CPM1 DATA	Description	Retention Requirements
ε_1	A constant derived from the targeted frequency bound. This number is the same for each Balancing Authority Area in the Interconnection.	Retain the value of ε_1 used in CPM1 calculation.
ACE_i	The clock-minute average of ACE.	Retain the 1-minute average values of ACE (up to 525,600 values).
B_i	The Frequency Bias of the Balancing Authority Area.	Retain the value(s) of B_i used in the CPM1 calculation.
F_A	The actual measured frequency.	Retain the 1-minute average frequency values (up to 525,600 values).
F_S	Scheduled frequency for the Interconnection.	Retain the 1-minute average frequency values (up to 525,600 values).

Standard BAL-002-0 — Operating Reserves

Introduction

1. **Title:** **Operating Reserves**

2. **Number:** BAL-002-1 – RS Proposed

3. **Purpose:**

   To ensure the balancing authority or reserve sharing group maintains adequate operating reserves and utilizes those reserves to balance resources and demand and return Interconnection frequency within defined limits. Operating reserves is the combination of contingency reserves used for loss of generation and regulation reserves.

4. **Applicability**:

   4.1 Balancing authorities

   4.2 Reserve sharing groups (balancing authorities may meet the requirements of the DCM standard requirements through participation in a reserve sharing group).

   4.3 Regional reliability organizations

5. **Proposed Effective Date**: Completion of Formal Standards Authorization Process

B. Requirements

Contingency reserves

Each Balancing authority shall have access to and/or operate contingency reserve to respond to disturbances. Contingency reserve may be supplied from generation, controllable load resources, or coordinated adjustments to Interchange Schedules.

A Balancing authority may elect to fulfill its contingency reserve obligations by participating as a member of a reserve sharing group. In such cases, the reserve sharing group shall have the same responsibilities and obligations as each balancing authority with respect to monitoring and meeting the requirements of Standard BAL-002.

R1. Each balancing authority or reserve sharing group shall at least annually update and specify its contingency reserve policies, including:

R1.1 The minimum reserve requirement

R1.2 The reserve sharing group's allocation among its members

R1.3 The permissible mix of operating reserve– spinning and operating reserve– supplemental that may be included in contingency reserve

R1.4 The procedure for applying contingency reserve in practice

R1.5 The limitations, if any, upon the amount of interruptible load that may be included

The same portion of resource capacity (e.g. reserves from jointly owned generation) shall not be counted more than once as contingency reserve by multiple balancing authorities.

R2. Each Balancing authority or reserve sharing group shall activate sufficient contingency reserves following a reportable disturbance to comply with the DCM within the disturbance recovery period.

Because generator failures are far more common than significant losses of load and because contingency reserve activation does not typically apply to the loss of load, the application of the DCM is limited to the loss of supply and does not apply to the loss of load.

R2.1 Each balancing authority shall comply with DCM. A balancing authority shall be considered in a reportable disturbance condition following the loss of generation equal to or greater than 80 percent of its largest unit on-line prior to the loss of generation. A balancing authority can comply with DCM by returning its ACE to zero if its ACE just prior to the reportable disturbance was positive or equal to zero. For negative initial ACE values just prior to the disturbance, the balancing authority shall return ACE to its pre-disturbance value.

R2.2 Each Reserve sharing group shall comply with the DCM. A reserve sharing group shall be considered in a reportable disturbance condition whenever a group member has experienced a reportable disturbance and calls for the activation of contingency reserves from one or more other group members. (If a group member has experienced a reportable disturbance but does not call for reserve activation from other members of the reserve sharing group, then that member shall report as a single balancing authority.) Compliance may be demonstrated by either of the following two methods:

R2.3 The Reserve sharing group reviews group ACE (or equivalent) and demonstrates compliance to the DCM. To be in compliance, the group ACE (or its equivalent) must meet the disturbance recovery criterion after the schedule change(s) related to reserve sharing have been fully implemented, and within the disturbance recovery period.

or

R2.4 The Reserve sharing group reviews each member's ACE in response to the activation of reserves. To be in compliance, a member's ACE (or its equivalent) must meet the DCM after the schedule change(s) related to reserve sharing have been fully implemented, and within the disturbance recovery period.

R2.5 A balancing authority or reserve sharing group shall fully restore its contingency reserves within the contingency reserve restoration period for its Interconnection. The default contingency reserve restoration period is 90 minutes and immediately follows the disturbance recovery period. This period may be adjusted to better suit the reliability targets of the Interconnection based on analysis approved by the NERC Operating Committee.

R2.6 A balancing authority or reserve sharing group shall meet the DCM within the disturbance recovery period for 100% of reportable disturbances.

R2.7 The default Disturbance Recovery Period is 15 minutes after the start of a reportable disturbance. This period may be adjusted to better suit the needs of an Interconnection based on analysis approved by the NERC Operating Committee.

Regulating Reserves

Each balancing authority shall have access to and/or operate regulating reserves to respond to changes in load demands both increasing and decreasing. Regulating reserves is supplied from generation resources under automatic generation control (AGC) or manually.

R3. Each Balancing authority shall operate such that its average ACE for at least 90% of clock-ten-minute periods (6 non-overlapping periods per hour) during a calendar month is within a specific limit, referred to as L_{10}.

$$AVG_{10-\text{minute}}(ACE_i) \leq L_{10}$$

where:

$L_{10} = 1.65 \in_{10} \sqrt{(-10B_i)(-10B_s)}$

- ε_{10} ($\varepsilon_1 / \sqrt{10}$), epsilon 10, is a constant derived from the targeted frequency bound. It is the targeted root-mean-square (RMS) value of ten-minute average frequency error based on frequency performance over a given year. The bound, ε_{10}, is the same for every Balancing authority Area within an Interconnection.
- 1.65 is a constant used to convert the frequency target to 90% probability. It is the number of standard deviations from the mean of a statistical normal distribution (Gausian distribution) that will result in a probability of noncompliance of 10% (i.e., compliance of 90%).
- B_i (MW/01 Hz) is the frequency bias of the balancing authority.
- B_s (MW/0.1 Hz) is the sum of the frequency bias settings of the balancing authority Areas in the respective Interconnection. For balancing authority Areas with variable bias, this is equal to the sum of the minimum Frequency Bias Settings.

R3.1 The ACE equation shall not include any balancing authority's control functions that are used for interchange operations. Control adjustments for unilateral inadvertent payback, automatic time-error correction, or other operational adjustment shall not be included in the ACE equation.

R 3.2 Each balancing authority that participates in the following activities shall comply with the requirements found in Standard BAL-005, Automatic Generation Control:

Supplemental Regulation Service

Overlap Regulation Service

Dynamic Schedules

Pseudo-ties

B. Measures

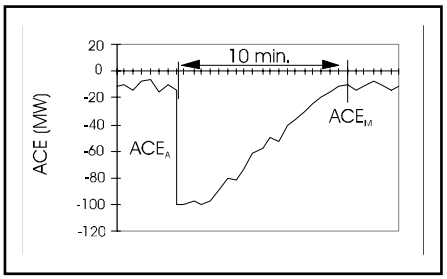
M1. Each balancing authority and reserve sharing group shall maintain and be able to produce its current contingency reserve policy.

M2. A Balancing authority or reserve sharing group shall calculate and report compliance with the Disturbance Control Measure (DCM) for all disturbances greater than or equal to 80% of the magnitude of the balancing authority's or of the reserve sharing group's most severe single contingency loss. Regions may, at their discretion, require a lower reporting threshold. DCM is measured as the percentage recovery (R_i).

For loss of generation:

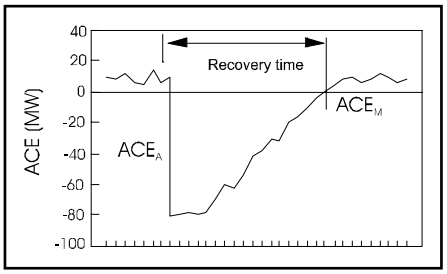
if $ACE_A < 0$
then

$$R_i = \frac{MW_{Loss} - \max(0, ACE_A - ACE_M)}{MW_{Loss}} * 100\%$$



if $ACE_A \geq 0$
then

$$R_i = \frac{MW_{Loss} - \max(0, -ACE_M)}{MW_{Loss}} * 100\%$$

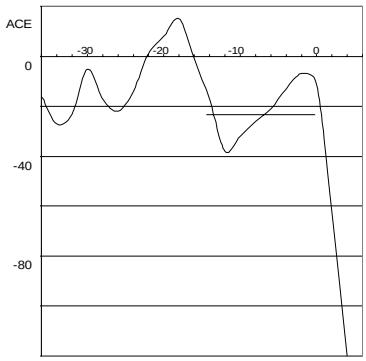


where:

- MW_{LOSS} is the MW size of the Disturbance as measured at the beginning of the loss,
- ACE_A is the pre-disturbance ACE,
- ACE_M is the maximum algebraic value of ACE measured within the fifteen minutes following the Disturbance. A Balancing authority or Reserve sharing group may, at its discretion, set $ACE_M = ACE_{15\ min}$, and
- ACE_m is the minimum algebraic value of ACE measured within the fifteen minutes following the Disturbance. A Balancing authority or reserve sharing group may, at their discretion, set $ACE_m = ACE_{15\ min}$.

The Balancing authority or reserve sharing group shall record the MW_{LOSS} value as measured at the site of the loss to the extent possible. The value should not be measured as a change in ACE since governor response and AGC response may introduce error.

The Balancing authority or Reserve sharing group shall base the value for ACE_A on the average ACE over the period just prior to the start of the Disturbance (10 and 60 seconds prior and including at least 4 scans of ACE). In the illustration below, the horizontal line represents an averaging of ACE for 15 seconds prior to the start of the Disturbance with a result of ACE_A = -25 MW.



The average percent recovery is the arithmetic average of all the calculated R_i's for reportable disturbances during a given quarter.

M3. Each Balancing authority shall achieve, as a minimum, Requirement R4 Compliance Performance Standard 2 (CPS2) compliance of 90%. CPS2 relates to a bound on the ten-minute average of ACE. A compliance percentage is calculated as follows:

$$CPS2 = \left[1 - \frac{\text{Violations}_{\text{month}}}{\left(\text{Total Periods}_{\text{month}} - \text{Unavailable Periods}_{\text{month}}\right)}\right] * 100$$

The violations per month are a count of the number of periods that ACE clock-ten-minutes exceeded L_{10}. ACE clock-ten-minutes is the sum of valid ACE samples within a clock-ten-minute period divided by the number of valid samples.

Violation clock-ten-minutes

= 0 if

$$\left|\frac{\sum ACE}{n_{\text{samples in 10-minutes}}}\right| \leq L_{10}$$

= 1 if

$$\left|\frac{\sum ACE}{n_{\text{samples in 10-minutes}}}\right| > L_{10}$$

Each Balancing authority shall report the total number of violations and unavailable periods for the month. L_{10} is defined in Requirement R2.

In order to ensure that the average ACE calculated for any ten-minute interval is representative of that ten-minute interval, it is necessary that at least half the ACE data samples (not necessarily contiguous) are present for that interval. Should more than half of the ACE data be unavailable due to loss of telemetering or computer unavailability, that ten-minute interval shall be omitted from the calculation of CPS2.

C. Compliance

1. Compliance Monitoring Process

Compliance with both the DCM and the CPS2 shall be measured on a percentage basis as set forth in the measures above.

For DCM, each Balancing authority or reserve sharing group shall submit one completed copy of DCM Form, "NERC Control Performance Standard Survey – All Interconnections" to its Resources Subcommittee Survey Contact no later than the 10th day following the end of the calendar quarter (i.e. April 10th, July 10th, October 10th, January 10th). The Regional Reliability Organization must submit a summary document reporting compliance with DCM to NERC no later than the 20th day of the month following the end of the quarter.

2. Compliance Monitoring Responsibility

Regional Reliability Organization.

3. Compliance Monitoring Period and Reset Timeframe

Compliance for DCM and CPS2 will be evaluated for each reporting period. Reset for DCM reserves is one calendar quarter without a violation.

4. Data Retention

The data that support the calculation of DCM and CPS2 are to be retained in electronic form for at least a one-year period. If the DCM or CPS2 data for a reserve sharing group or balancing authority are undergoing a review to address a question that has been raised regarding the data, the data are to be saved beyond the normal retention period until the question is formally resolved.

5. Additional Compliance Information

Reportable Disturbances – Reportable Disturbances are contingencies that are greater than or equal to 80% of the most severe single Contingency. A Regional Reliability Organization, sub-Regional Reliability Organization or Reserve sharing group may optionally reduce the 80% threshold, provided that normal operating characteristics are not being considered or misrepresented as contingencies. Normal operating characteristics are excluded because DCM only measures the recovery from sudden, unanticipated losses of supply-side resources.

Simultaneous Contingencies – Multiple Contingencies occurring within one minute or less of each other shall be treated as a single Contingency. If the combined magnitude of the multiple Contingencies exceeds the most severe single Contingency, the loss shall be reported, but excluded from compliance evaluation.

Multiple Contingencies within the Reportable Disturbance Period – Additional Contingencies that occur after one minute of the start of a Reportable Disturbance but before the end of the Disturbance Recovery Period can be excluded from evaluation. The Balancing authority or Reserve sharing group shall determine the DCM compliance of the initial Reportable Disturbance by performing a reasonable estimation of the response that would have occurred had the second and subsequent contingencies not occurred.

Multiple Contingencies within the Contingency reserve Restoration Period – Additional Reportable Disturbances that occur after the end of the Disturbance Recovery Period but before the end of the Contingency reserve Restoration Period shall be reported and included in the compliance evaluation. However, the Balancing authority or Reserve sharing group can request a waiver from the Resources Subcommittee for the event if the contingency reserves were rendered inadequate by prior contingencies and a good faith effort to replace contingency reserve can be shown.

6. Levels of Non-Compliance

Each Balancing authority or Reserve sharing group not meeting the DCM during a given calendar quarter shall increase its contingency reserve obligation for the calendar quarter (offset by one month) following the evaluation by the NERC or Compliance Monitor [e.g. for the first calendar quarter of the year, the penalty is applied for May, June, and July.] The increase shall be directly proportional to the non-compliance with the DCM in the preceding quarter. This adjustment is not compounded across quarters, and is an additional percentage of reserve needed beyond the most severe single Contingency. A Reserve sharing group may choose an allocation method for increasing its Contingency reserve for the Reserve sharing group provided that this increase is fully allocated.

A representative from each Balancing authority or Reserve sharing group that was non-compliant in the calendar quarter most recently completed shall provide written documentation verifying that the balancing authority or reserve sharing group will apply the appropriate DCM performance adjustment beginning the first day of the succeeding month, and will continue to apply it for three months. The written documentation shall accompany the quarterly Disturbance Control Measure Report when a balancing authority or reserve sharing group is non-compliant.

Level of Non-Compliance - Contingency Reserve Policy

Level 1: The balancing authority or reserve sharing group did not update its contingency reserve policy annually.

Level 2: The balancing authority or reserve sharing group was not able to produce a current contingency reserve policy.

Levels of Non-Compliance - DCM

Level 1: Value of the average percent recovery for the quarter is less than 100% but greater than or equal to 95%.

Level 2: Value of the average percent recovery for the quarter is less than 95% but greater than or equal to 90%.

Level 3: Value of average percent recovery for the quarter is less than 90% but greater than or equal to 85%.

Level 4: Value of average percent recovery for the quarter is less than 85%.

Levels of Non-Compliance – CPS2

Level 1: The Balancing authority Area's value of CPS2 is less than 90% but greater than or equal to 85%.

Level 2: The Balancing authority Area's value of CPS2 is less than 85% but greater than or equal to 80%.

Level 3: The Balancing authority Area's value of CPS2 is less than 80% but greater than or equal to 75%.

Level 4: The Balancing authority Area's value of CPS2 is less than 75%.

7. Regional Differences

CPS2 is not applicable to a single Balancing authority Interconnection (ERCOT).

Version History

Version	Date	Action	Change Tracking

A. Introduction

1. **Title:** **Frequency Response and Bias**

2. **Number:** BAL-003-1 – RS Proposed

3. **Purpose:** This standard provides:
   - **3.1.** An objective measure of the balancing authority's sub-minute response to changes in frequency.
   - **3.2.** A consistent method for calculating and setting the frequency bias component of ACE.
   - **3.3.** Long-term interconnection target levels for average response to frequency excursions, performance below which triggers balancing authority and regional reliability organization evaluation and analysis.

4. **Applicability:**
   - **4.1.** Balancing Authorities
   - **4.2.** Regional Reliability Organizations

5. **Proposed Effective Date:** Completion of Formal Standards Authorization Process

B. Requirements

R1. Each balancing authority shall review its frequency bias settings by January 1 of each year and recalculate its setting to reflect any change in the frequency response of the balancing authority area.

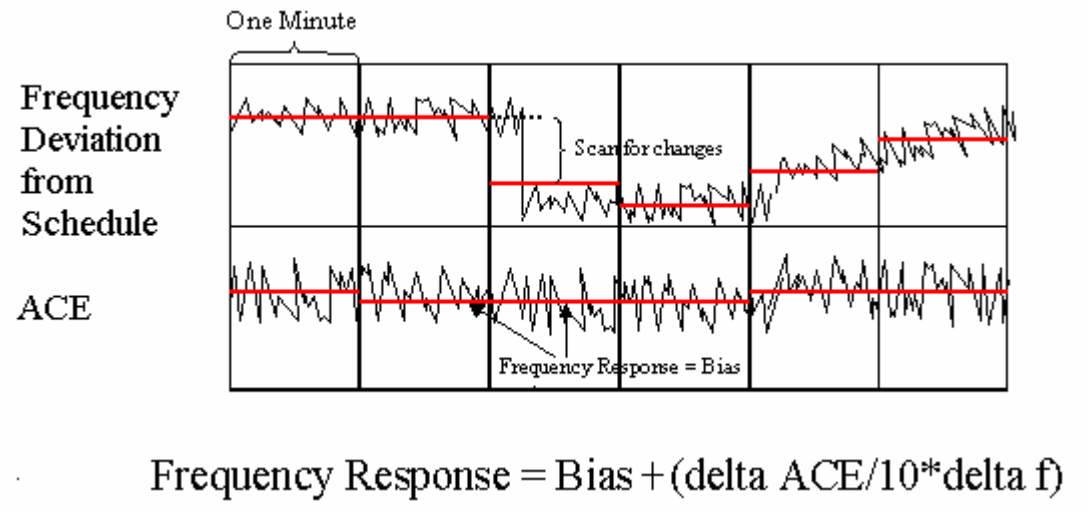
- **R1.1.** The balancing authority may change its frequency bias setting, and the method used to determine the setting, whenever any of the factors used to determine the current bias value change.
- **R1.2.** Each balancing authority shall report both its frequency bias setting and calculated median and average annual frequency response to the NERC operating committee.

R2. The method and events selected for calculating frequency bias shall be from one of the following:

- **R2.1.** A list provided by the Interconnection of at least 5 on-peak events each month.
- **R2.2.** An automated process that captures all step changes in frequency beyond an interconnection target. The interconnection target shall be approved by the operating committee

R3. The frequency response calculation for determining the frequency bias setting shall be based on either:

- **R3.1.** The tie line deviation (or ACE) immediately before the step change in frequency versus the average tie line deviation (or average ACE) for 60 seconds after the step change in frequency.
- **R3.2.** The one-minute average CPS source data (ACE and frequency deviation from schedule) immediately before and including the step change in frequency.



R4. Each balancing authority shall establish and maintain a frequency bias setting that is as close as practical to, or greater than, the balancing authority's frequency response. The frequency bias used may be calculated by either of the following::

R4.1. The balancing authority may use a fixed frequency bias value which is based on a fixed, straight-line function of tie line deviation (or change in ACE) versus frequency deviation.

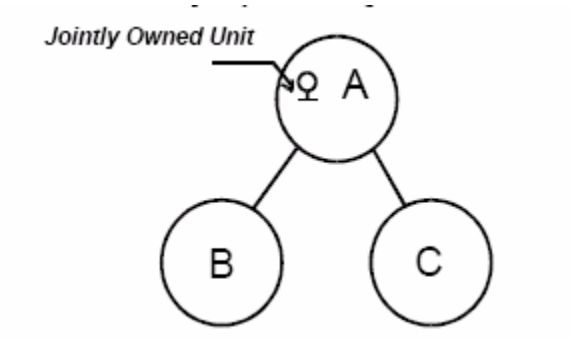
R4.2. The balancing authority may use a variable (linear or non-linear) bias value, which is based on a variable function of tie line deviation to frequency deviation. The balancing authority shall determine the variable frequency bias value by analyzing frequency response as it varies with factors such as load, generation, governor characteristics, and frequency.

R5. Each balancing authority shall operate its automatic generation control (AGC) on tie line frequency bias, unless such operation is adverse to system or interconnection reliability.

R6. Balancing authorities that use dynamic scheduling or pseudo-ties for jointly owned units shall reflect their respective share of the unit governor droop response in their respective frequency bias setting.

R6.1. Fixed schedules for jointly owned units mandate that balancing authority (A) that contains the jointly owned unit must incorporate the respective share of the unit governor droop response for any balancing authorities that have fixed schedules (B and C). See the diagram below.

R6.2. The balancing authorities that have a fixed schedule (B and C) but do not contain the Jointly Owned Unit shall not include their share of the governor droop response in their frequency bias setting.



R7. The NERC operating committee will establish a target frequency response (expressed in percent of peak load) for each interconnection. The target frequency response will initially be the average frequency response of each interconnection observed in the first year of this standard.

R8. Minimum Bias.

R8.1. Balancing authorities that serve native load shall have a monthly average frequency bias setting that is at least 1% of the balancing authority's estimated monthly (or yearly) peak demand per 0.1 Hz change.

R8.2. Balancing authorities that do not serve native load shall have a monthly average FREQUENCY BIAS setting that is at least 1% of its estimated maximum generation level in the coming year per 0.1 Hz change.

R8.3. Exception. Balancing authorities providing at least their share of the target interconnection frequency response may use a frequency bias value equal to or greater than their natural frequency response. (i.e. they have an exception to the 1% rule).

R9. Balancing authorities with less than 70% of their share of target interconnection frequency response shall, in conjunction with their region, assess:

R9.1. The performance of their generator governors to specifications. This assessment may be either through individual generator tests or via the implementation of a centralized online calculation similar to Requirement R3 (using changes in generator output rather than ACE or tie line deviation).

R9.2. The ability of the balancing authority to maintain a stable frequency during blackstart.

R9.3. The balancing authority and region shall make this assessment within 12 months of each January in which the balancing authority is below their 70% share of the target interconnection frequency response.

R10. A balancing authority that is performing overlap regulation service shall increase its frequency bias setting to match the frequency response of the entire area being controlled. A balancing authority shall not change its frequency bias setting when performing supplemental regulation service.

R11. Regions shall use the annual reported balancing authority calculated frequency response in models for reliability studies as opposed to theoretical frequency response based on typical droop settings.

R12. Governor installation and operation.

R12.1. Generating units with nameplate ratings of 10 MW or greater shall be equipped with governors.

R12.2. All turbine generators equipped with governors shall be capable of providing immediate and (evaluate if this "and" should be "or") sustained response to frequency deviations when synchronized to the interconnection.

R12.3. Governors shall provide between a 4% and 7% droop characteristic.

R12.4. Governors shall, as a minimum, respond to frequency deviations with a deadband not exceeding ± 0.036 Hz (± 36 mHz).

R12.5. Exceptions. Generating units may receive an exemption from their regional reliability organization to the governor operation and the governor characteristics such as deadband, droop and sliding pressure control if any of the following apply:

R5.12.1. Supported by engineering studies or regulatory mandates.

R5.12.2. The balancing authority provides greater than a 100% share of target interconnection frequency response and such governors can be placed in a responsive mode during disturbances and blackstart.

R12.6. Any governors not operational for frequency response shall be identified in a report accompanying the annual frequency bias calculation.

C. Measures

M1. Each balancing authority shall perform frequency response surveys when called for by the operating committee to determine the balancing authority's response to interconnection frequency deviations.

M2. Each balancing authority shall perform and report an annual calculation of its frequency response and bias setting. Any generators with non-responsive governors will be identified along with this annual report.

M3. Each balancing authority with an annual frequency response less than 70% of the target interconnection frequency response will perform an assessment of its restoration and blackstart capabilities. This assessment will be done within 12 months of the January report of frequency response and bias.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframe

One calendar year.

1.3. Data Retention. The balancing authority shall retain the data used to calculate frequency response for a period of 3 years.

2. Levels of Non-Compliance

2.1. Level 1:

2.2. Level 2: The BALANCING AUTHORITY did not calculate and report its annual FREQUENCY RESPONSE and BIAS.

2.3. Level 3: The balancing authority with less than 75% of its share of target interconnection frequency response did not perform its required assessment of governor performance and ability to maintain a stable frequency during blackstart.

2.4. Level 4:

E. Regional Differences

Single balancing authority interconnections calculate frequency response based on the change in generation (or load) rather than tie line deviation.

Version History

Version	Date	Action	Change Tracking

003-1	July 31, 2005	Initial draft based on comments to the SAR.

A. Introduction

1. **Title:** **Time Error Correction**
2. **Number:** BAL-004-1 – RS Proposed
3. **Purpose:**

   The purpose of this standard is to ensure that time error corrections are conducted in a manner that does not adversely affect the reliability of the interconnection.
4. **Applicability:**
   - **4.1.** Reliability Coordinators
   - **4.2.** Balancing Authorities
   - **4.3.** Interconnection Time Error Monitors
5. **Proposed Effective Date:** Completion of Formal Standards Authorization Process

B. Requirements

Interconnection Time Error Monitoring

R1. Only a reliability coordinator shall be eligible to act as interconnection time monitor. A single reliability coordinator in each Interconnection shall be designated by the NERC operating committee to serve as the interconnection time monitor.

R2. An interconnection time monitor shall exist for each interconnection.

R3. The interconnection time monitor shall monitor time error and shall initiate or terminate manual time error corrective action orders.

R4. Each balancing authority shall participate in automatic time error correction unless it is operating asynchronously to its interconnection.

R5. The interconnection time monitor shall calibrate its time error device at least annually against the National Bureau of Standards time.

R6. At least once each day, every balancing authority shall synchronize its time error to the nearest 0.001 seconds with the system time error as determined by the interconnection time monitor.

- **R1.6.1.** Daily, the interconnection time monitor shall read the value of the interconnection system time error at a designated time each day (e.g. Western Interconnection time synchronization occurs at 14:00:00 hours Pacific Prevailing Time) and shall broadcast it to all balancing authorities within 15 minutes of the designated time.
- **R1.6.2.** Each balancing authority shall synchronize its time error to the nearest 0.001 seconds of the system time error by comparing its reading at the designated time each day to the reading broadcast by the interconnection time monitor; any difference shall be applied as an adjustment to its current time error.

Automatic Time Error Correction

R7. Each balancing authority that operates synchronously to its Interconnection shall continuously operate utilizing the automatic time error correction (ATEC) metric in its AGC system.

R8. Any balancing authority that removes the automatic time error correction metric from its AGC system, other than for routine maintenance, shall notify all other balancing authorities through the designated interconnection Internet communication system.

R9. Balancing authorities shall be able to change their AGC operating mode between:

R9.1. Flat Frequency (for blackout restoration)

R9.2. Flat Tie Line (for loss of frequency error telemetry)

R9.3. Tie Line Bias (this is the default NERC equation used for CPS)

R9.4. Tie Line Bias plus Time Error control (used in Automatic Time Error Correction mode)

R10. Each balancing authority shall compute its hourly inadvertent interchange at the end of each hour. This hourly value shall be added to the appropriate accumulated Inadvertent Interchange balance for either On-Peak or Off-Peak periods

R11. Each balancing authority shall use its own time error readings derived from the same frequency source it is using in the ACE frequency bias obligation term.

R12. Each balancing authority shall use the ATEC equation (automatic time error correction) when operating in the automatic time error correction mode:

$$ATEC_i = \left(NI_A - NI'_S\right) - 10B_i\left(F_A - F_S\right) - T_{0b} + I_{ME}$$

Where:

NI_A = Net Interchange Actual (MW)

F_A = Frequency Actual (Hz)

F_S = Frequency Scheduled (Normally 60 Hz).

B_i = Frequency Bias for the Balancing Authority's Area i (MW / 0.1 Hz)

H = Number of Hours used to payback Inadvertent Interchange Energy.

T_{0b} = Remaining Bilateral Payback for Inadvertent Interchange created prior to implementation of automatic payback. (MW)

I_{ME} = Meter Error Correction (MW)

$$NI'_S = NI_S - \frac{II_{\text{Primary}}^{on/off\ peak}}{(1-Y)*H}$$

NI_S = Net Interchange Scheduled (MW)

Y = B_i / B_S.

B_s = Frequency Bias for the Interconnection (MW / 0.1 Hz)

$\sum II_{\text{primary}}^{\text{on/off peak}}$ = is the Control Area's accumulated primary inadvertent interchange in MWh. An On-Peak and Off-Peak accumulation accounting is required.

Where:

$\sum II_{\text{primary}}^{\text{on/off peak}}$ **= last period's** $\sum II_{\text{primary}}^{\text{on/off peak}}$ **+ (1-Y) * (II_{actual} - B_i * ΔTE/6)**

II_{actual} is the hourly inadvertent interchange for the last hour

ΔTE is the hourly change in system time error adjusted for any manual time error corrections and time error adjustments

Where:

$$\Delta TE = TE_{end\ hour} - TE_{begin\ hour} - TD_{adj} - (t)*(TE\ offset)$$

TD_{adj} is any operator adjustment to the control center time error to correct for differences with the time monitor.

t is the number of minutes of manual time correction that occurred during the hour.

TE offset is usually either +0.020 seconds or -0.020 seconds or 0.000 seconds. The Time Monitor may declare offsets in 0.001-second increments.

Manual Time Error Correction

R13. When a manual time error correction is announced, the interconnection time monitor shall:

R13.1. Specify it is a correction for fast time error or slow time error.

R13.2. Specify the start time

R13.3. Specify the scheduled frequency

R13.4. Specify the duration of the time error correction

R14. Manual time error corrections shall start and end on the hour or half-hour, and notice shall be given at least twenty minutes before the time error correction is to start or stop.

R15. Time error corrections shall last at least one hour, unless terminated by a reliability coordinator.

R16. Each interconnection time monitor shall monitor time error and shall initiate or terminate manual time error corrective action orders according to the following table:

Time (seconds)	***Initiation***			***Termination***		
	East	**West**	**ERCOT**	**East**	**West**	**ERCOT**
Slow	-10	-5	-3	-6	±0.5	±0.5
Fast	+10	+5	+3	+6	±0.5	±0.5

R17. All balancing authorities within an interconnection shall fully participate in manual time error corrections.

R18. Manual time error correction notification shall be labeled alphabetically on a monthly basis (A-Z, AA-AZ, BA-BZ, . . .).

R19. Each balancing authority, when requested by the interconnection time monitor, shall participate in a manual time error correction by one of the following methods:

R19.1. The balancing authority shall offset its frequency schedule by 0.02 Hertz, leaving the frequency bias setting normal; or

R19.2. If the frequency schedule cannot be offset as directed by the interconnection time monitor, the balancing authority shall offset its net interchange schedule (MW) by an amount equal to the computed bias contribution during a 0.02 Hertz frequency deviation (i.e. 20% of the frequency bias setting).

R20. Any reliability coordinator has the authority to request the interconnection time monitor to terminate a manual time error correction in progress, or scheduled that has not begun, for reliability considerations.

R20.1. Balancing authorities that have reliability concerns with the execution of a manual time error correction shall notify their reliability coordinator and request the termination of the manual time error correction in progress.

Inadvertent Interchange On and Off Peak Periods

Note: It is currently intended to leave the On- and Off-Peak definition in the NAESB Business Practices. The following requirements are included here for reference only.

R21. The hourly inadvertent energy accumulated by a balancing authority is classified as either On-Peak or Off-Peak inadvertent interchange. The peak designation assigned is a function of hour of day, day of week, time zone, prevailing time (standard or daylight savings), and special holiday status.

R22. The On-Peak to Off-Peak and Off-Peak to On-Peak boundary hours are unaffected by transitions to or from daylight savings time. If a balancing authority remains on either standard or daylight savings time throughout the year, their inadvertent interchange accounting periods must be adjusted to coordinate with prevailing time used by the rest of the Interconnection.

R23. Each interconnection shall have a reference time zone and standardized On-Peak and Off-Peak periods. On-Peak periods are summarized in the table below for each Interconnection. Sundays and special holidays are designated to be Off-Peak periods for the entire day. Hours for Monday through Saturday that are not shown in the table below are also designated as Off-Peak hours.

Interconnection	**Reference Time Zone**	***Hour Ending***	
		From	***To***
Eastern	Central	0700	2200
ERCOT	Central	0800	2200
Western	Pacific	0700	2200

R24. Six U.S. Holidays shall be recognized as Off-Peak hours for the entire day. If any of these holidays fall on a Sunday, the following Monday will be considered an Off-Peak day. Otherwise, the Off-Peak day will be the holiday itself.

New Year's Day

Memorial Day

Independence Day

Labor Day

Thanksgiving Day

Christmas Day

C. Measures

Not specified.

D. Compliance

Not specified.

E. Regional Differences

1. For regions in the Eastern Interconnection manual time error corrections for fast-time shall not be initiated between 0400-1100 Central Prevailing Time.

Version History

Version	Date	Action	Change Tracking

1. Title: **Automatic Generation Control**

2. Number: BAL-005-1 – RS Proposed

3. Purpose:

This standard establishes requirements for balancing authority automatic generation control (AGC) necessary to calculate area control error (ACE) and to routinely deploy the regulating reserve. The standard also ensures that all facilities and load electrically synchronized to the interconnection are included within the metered boundary of a balancing area so that balancing of resources and demand can be achieved.

4. Applicability:

4.1. Balancing Authorities

4.2. Generator Operators

4.3. Transmission Operators

4.4. Load Serving Entities

5. Proposed Effective Date: Completion of Formal Standards Process

B. Requirements

R1. All generation, transmission, and load operating within an Interconnection must be included within the metered boundaries of a balancing authority Area.

R1.1. Each generator operator with generation facilities operating in an Interconnection shall ensure that those generation facilities are included within the metered boundaries of a balancing authority area.

R1.2. Each transmission operator with transmission facilities operating in an Interconnection shall ensure that those transmission facilities are included within the metered boundaries of a balancing authority area.

R1.3. Each load-serving entity with load operating in an Interconnection shall ensure that those loads are included within the metered boundaries of a balancing authority area.

R2. Each balancing authority shall maintain regulating reserve that can be controlled by AGC to meet the control performance standard.

R3. The balancing authority's AGC shall compare total net actual interchange to total net scheduled interchange plus frequency bias obligation to determine the balancing authority'sACE.

R3.1. The balancing authority shall include all interchange schedules with adjacent balancing authorities in the calculation of net scheduled interchange for the ACE equation.

R1.3.1. Balancing authorities that share a tie shall ensure tie line MW metering is telemetered to both control centers, and emanates from a common, agreed-upon source using common primary metering equipment. Balancing authorities shall ensure that megawatt-hour data is telemetered or reported at the end of each hour.

R1.3.2. Balancing authorities shall ensure the power flow and ACE signals that are utilized for calculating balancing authority performance or that are transmitted for regulation service are not filtered prior to transmission, except for the Anti-aliasing filters of tie lines.

R1.3.3. Balancing authorities shall install common metering equipment where dynamic schedules or pseudo-ties are implemented between two or more balancing authorities to deliver the output of jointly owned units or to serve remote load.

R1.3.4. Balancing authorities with a high voltage direct current (HVDC) link to another balancing authority connected asynchronously to their Interconnection may choose to omit the interchange schedule related to the HVDC link from the ACE equation if it is modeled as internal generation or load.

R1.3.5. The balancing authority shall include all dynamic schedules in the calculation of net scheduled interchange for the ACE equation.

R1.3.6. Each balancing authority shall include in its ACE calculation the pseudo-ties that are implemented between two or more balancing authorities.

R1.3.7. Balancing authorities shall include the effect of ramp rates, which shall be identical and agreed to between affected balancing authorities, in the Scheduled Interchange values to calculate ACE.

R3.2. All dynamic transfers utilized by the BA for the calculation of ACE shall be implemented as per the requirements of the current revision of the NERC Dynamic Transfer Reference Manual

R2.3.1. Appropriate telemetry must be in place and incorporated by all affected CONTROL AREAS.

R2.3.2. Prior to implementation of the dynamic transfer of load or generation, it is the obligation of each involved CONTROL AREA to ensure that the dynamic transfer is implemented such that the tariff requirements of the applicable TRANSMISSION PROVIDER(S) are met, including applicable ancillary services and provision of losses.

R2.3.3. 2.2. If transmission service between the SOURCE and SINK CONTROL AREAs is curtailed then the allowable range of the magnitude of the schedules between them, including DYNAMIC SCHEDULES, may have to be curtailed accordingly.

R2.3.4. It is the obligation of each CONTROL AREA to ensure that the dynamic transfer of load or generation through a dynamic schedule is coordinated with the RELIABILITY COORDINATOR(S) with responsibility over the Native, Attaining and CONTRACT INTERMEDIARY CONTROL AREAS so that the dynamic schedule can be properly implemented in the system modeling of the affected generation or load, and necessary data provision requirements are met. Coordination must include tagging of the resultant

R3.3. The balancing authority shall provide adequate and reliable backup power supplies and shall periodically test these supplies at the balancing authority's control center and other critical locations to ensure continuous operation of AGC and vital data recording equipment during loss of the normal power supply.

R3.4. Each balancing authority shall provide redundant and independent frequency metering equipment that shall automatically activate upon detection of failure of the primary source. This overall installation shall provide a minimum availability of 99.95%.

R3.5. If a balancing authority is unable to calculate ACE for more than 30 minutes it shall notify its reliability coordinator.

R4. Each balancing authority shall perform hourly error checks using tie line megawatt-hour meters with common time synchronization to determine the accuracy of its control equipment. The balancing authority shall adjust the component (e.g., tie line meter) of ACE that is in error (if known) or use the interchange meter error (IME) term of the ACE equation to compensate for any equipment error until repairs can be made.

R4.1. The balancing authority shall provide its operating personnel with sufficient instrumentation and data recording equipment to facilitate monitoring of control performance, generation response, and after-the-fact analysis of area performance. As a minimum, the balancing authority shall provide its operating personnel with real-time values for ACE, interconnection frequency and net actual interchange with each adjacent balancing authority area.

R4.2. The balancing authority shall sample data at least at the same periodicity with which ACE is calculated. The balancing authority shall flag missing or bad data for operator display and archival purposes. The balancing authority shall collect coincident data to the greatest practical extent, i.e., ACE, interconnection frequency, net actual interchange, and other data shall all be sampled at the same time.

R4.3. R4.11. Each balancing authority shall at least annually check and calibrate its time error and frequency devices against a common reference. The balancing authority shall adhere to the minimum values for measuring devices as listed below:

Device	Accuracy
Digital frequency transducer	≤ 0.001 Hz
MW, MVAR, and voltage transducer	≤ 0.25 % of full scale
Remote terminal unit	≤ 0.25 % of full scale
Potential transformer	≤ 0.30 % of full scale
Current transformer	≤ 0.50 % of full scale

C. Measures

M1. All generation, transmission and load operating within an an interconnection shall be verified to be within a balancing authority during all energy schedule creation, transmission tag process, and control performance measure data process.

M2. The resources subcommittee shall monitor frequency and control performance measures and shall randomly survey balancing authorities when the resources subcommittee suspects any balancing authority is not supporting frequency with regulation reserves, supplemental regulation reserves, or overlap regulation reserves.

M3. The compliance monitor shall conduct scheduled audits to verify that each balancing authority operates on automatic generation control continuously unless such operation adversely impacts the reliability of the interconnection.

M4. The compliance monitor shall conduct scheduled audits to verify that each balancing authority calculates its automatic control error in compliance with the BAL-005 requirements.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Balancing authorities shall be prepared to supply data to NERC in the format defined below:

1.1.1. Within one week upon request, balancing authorities shall provide NERC or the regional reliability organization CPM source data in daily CSV files with time stamped one minute averages of: 1) ACE and 2) Frequency Error.

1.1.2. Within one week upon request, balancing authorities shall provide NERC or the regional reliability organization DCS source data in CSV files with time stamped scan rate values for: 1) ACE and 2) Frequency Error for a time period of two minutes prior to thirty minutes after the identified disturbance.

1.2. Compliance Monitoring Period and Reset Timeframe

Not specified.

1.3. Data Retention

1.3.1. Each balancing authority shall retain its ACE, actual frequency, scheduled rrequency, net actual interchange, net scheduled interchange, tie line meter error correction and frequency bias setting data in digital format at the same scan rate at which the data is collected for at least one year.

1.3.2. Each balancing authority or reserve sharing group shall retain documentation of the magnitude of each reportable disturbance as well as the ACE charts and/or samples used to calculate Balancing Authority or reserve sharing group disturbance recovery values. The data shall be retained for one year following the reporting quarter for which the data was recorded.

1.4. Additional Compliance Information –

Not specified.

1.4. Levels of Non-Compliance

Not specified.

D. Regional Differences

None identified.

Section 1.01 Version History

Version	Date	Action	Change Tracking

Deleted: 0

Deleted: Inadvertent Interchange

A. Add the following terms to the NERC Glossary of Terms:

B. Jointly Owned Generating Units: Generating unit(s) in which two or more entities dynamically share the output.

C. Remote Load: A balancing authority's energy load that is electrically located in a different balancing authority area.

D. Interchange: Energy transfers that cross balancing authority area boundaries.

Deleted: 0

Deleted: Inadvertent Interchange

This is a Resources Subcommittee, Inadvertent Interchange Task Force Draft Revision (Pre-SAR) of Standard BAL-006-0, Inadvertent Interchange.

E. Introduction

1. **Title:** **Inadvertent Interchange**
2. **Number:** BAL-006-1 – RS Proposed
3. **Purpose:**

   This standard defines a process for monitoring balancing authorities to ensure that, over the long term, Balancing authority areas do not excessively depend on other Balancing authority areas in the Interconnection for meeting their demand or Interchange obligations.

4. **Applicability:**

   4.1. Balancing Authorities.

5. **Proposed Effective Date** Completion of Formal Standards Authorization Process

F. Requirements

R1. Each balancing authority shall calculate and record hourly inadvertent interchange.

Mathematically, Inadvertent Interchange is the time integral of the deviation of a Balancing Authority's actual net interchange from its scheduled net interchange:

$$NI_i = NI_A - NI_S$$

Where:

***NI*$_i$** = Net inadvertent interchange for balancing authority i (MWh). Negative values of inadvertent interchange denote a condition of under-generation and positive values denote over-generation.

***NI*$_A$** = Net actual interchange for balancing authority i (MWh). This is the algebraic sum of the hourly integrated energy on a balancing authority's tie lines including pseudo-ties for any jointly owned generating units or remote load. Net actual interchange is positive for power leaving the system and negative for power entering.

***NI*$_S$** = Net scheduled interchange for balancing authority i (MWh). This is the mutually prearranged net energy on a balancing authority's tie lines including dynamic schedules or fixed schedules for any jointly owned generating units or remote load. Net scheduled interchange is positive for power scheduled to be delivered from the balancing area and negative for power scheduled to be received into the balancing area.

R2. Each balancing authority shall calculate and maintain its accumulated inadvertent interchange:

$$II_i = \sum NI_i + T_{ob}$$

Where: **IIi** = Accumulated inadvertent interchange for balancing authority i (MW)

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Deleted: Inadvertent Interchange

NI_i = Net inadvertent interchange for balancing authority i (MW). Negative values of inadvertent interchange denote a condition of under-generation and positive values denote over-generation.

T_{ob} = Remaining bilateral payback for inadvertent interchange created prior to implementation of Automatic Time Error Correction payback program. This value will be zero when all inadvertent interchange created prior to implementation of ATEC is settled.

R3. Remaining bilateral payback for inadvertent interchange created prior to implementation of automatic time error correction shall be settled via bilateral transactions and shall not be settled through the automatic time error correction metric. *Reference Standard BAL-004, Time Error Correction.*

R4. Balancing authorities shall compute hourly inadvertent interchange every hour and shall add this hourly inadvertent interchange value to the appropriate accumulated On-Peak or Off-Peak balance. *On-Peak and Off-Peak periods are defined by the North American Energy Standards Board.*

R5. Each balancing authority shall include all AC tie lines that connect to its adjacent balancing authority areas in its inadvertent interchange account. The balancing authority shall take into account interchange served by jointly owned generators.

R6. Each balancing authority shall ensure all of its balancing authority area interconnection points are equipped with common megawatt-hour meters, with readings provided hourly to the control centers of adjacent balancing authorities.

R7. Adjacent balancing authority areas shall operate to a common net scheduled interchange and net actual interchange value; shall record these hourly quantities with like values but opposite sign; and shall enter these values into the NERC operating committee designated inadvertent interchange electronic application. Each balancing authority shall compute its inadvertent interchange based on the following:

R7.1. Each balancing authority, by the end of the next business day, shall agree with its adjacent balancing authorities to:

R7.1.1. The hourly values of net schedule interchange.

R7.1.2. The hourly integrated megawatt-hour values of net actual interchange.

R7.2. Each balancing authority shall enter agreed-to hourly adjustment values into the NERC OC designated inadvertent interchange electronic application.

R7.3. Each balancing authority shall use the agreed-to hourly, daily, and monthly accounting data to compile its monthly accumulated inadvertent interchange for the On-Peak and Off-Peak hours of the month. The NERC operating committee may designate the NERC operating committee designated inadvertent interchange electronic application to satisfy this requirement.

R7.4. Each balancing authority shall make after-the-fact corrections to the agreed-to hourly, daily and monthly accounting data only as needed to reflect actual operating conditions (e.g., a meter being used for control was sending bad data). Changes or corrections based on non-reliability considerations shall not be reflected in the balancing authority's inadvertent interchange. After-the-fact corrections to scheduled or actual interchange values will not be accepted without agreement of the adjacent balancing authority(ies).

R7.5. Financially settled inadvertent interchange shall be removed from inadvertent interchange balances.

R8. Adjustments shall be made at least once each month to correct for differences between hourly MWh telemeter totals and the totals derived from register readings at the tie line meters.

R8.2. Differences. Adjacent balancing authorities shall agree upon the difference determined above and assign this correction to the proper On-Peak and Off-Peak period at the same times and in equal quantities in the opposite directions.

R8.3. Adjustments. Any adjustments necessary due to known metering errors, franchised territories, transmission losses or other special circumstances shall be made to the proper On-Peak and Off-Peak period at the same times and in equal quantities in the opposite directions.

R9. Each balancing authority shall post a monthly accounting of all net actual interchange and net scheduled interchange with all adjacent balancing authorities, in MWh, to the NERC designated website. These postings shall not include any after-the-fact changes that were not agreed to by the source balancing authority, sink balancing authority, and all intermediary balancing authorities. The NERC operating committee may designate the NERC operating committee designated inadvertent interchange electronic application to satisfy this requirement.

R9.2. Interchange Postings. Each balancing authority shall post its monthly interchange values with adjacent balancing authorities by the 15th calendar day of the following month. The NERC compliance staff will prepare a composite tabulation identifying all disputed interchange by the 22nd calendar day of the month and send it to the regional compliance mangers.

R9.3. Failure to Report. A balancing authority that neither posts its interchange values nor supplies their regional compliance manager with a reason for not submitting the required data by the 21st calendar day of the following month shall be considered non-compliant.

R10. For purposes of dispute resolution, adjacent balancing authorities that cannot mutually agree upon their respective net actual interchange or net scheduled interchange quantities by the 15th calendar day of the following month shall submit a report to their respective regional compliance manager by the 20th calendar day of the following month. The report shall describe the nature and the cause of the dispute as well as a process for correcting the discrepancy.

R10.2. Regional Compliance Manager reporting requirements. The regional compliance manager shall accept the balancing authority's report describing the disputed values. If the dispute is between balancing authorities in different regions, that regional compliance manager shall contact the regional compliance manager for the opposing balancing authority. By the 25th day of the following month, the regional compliance manager(s) shall determine a set of values, which will be reported to the NERC compliance manager and notify the disputing balancing authorities. The report(s) will identify:

- The names of the disputing balancing authorities.
- The reported monthly net scheduled interchange (On-Peak and Off-Peak) between the disputing balancing authorities.
- The mutually agreed to monthly net scheduled interchange (On-Peak and Off-Peak) between the disputing balancing authorities (used to compute the regional inadvertent interchange).

- The reported monthly net actual interchange (On-Peak and Off-Peak) between the disputing balancing authorities.

- The mutually agreed to monthly net actual interchange (On-Peak and Off-Peak) between the disputing balancing authorities (used to compute the regional inadvertent interchange).

R10.3. NERC Compliance Staff reporting requirements. The NERC compliance staff shall retrieve the monthly interchange information and, using the mutually agreed to data, compile a balanced inadvertent interchange summary report. This report will also include a tabulated list of the balancing authorities that have disputed data, as well as the magnitude of the data in dispute. This report will be distributed to the operating committee and the resources subcommittee by the first day of the succeeding month.

R10.4. Dispute Resolution. All disputes between balancing authorities within a region shall be referred to the regional process for dispute resolution to resolve the dispute on an informal basis within 30 days of the issuance of the NERC inadvertent interchange summary report.

All disputes between balancing authorities in different regions shall be referred to the respective regions' operating committee representatives, or other regional-approved representatives, for resolution on an informal basis within 30 days of the issuance of the NERC inadvertent interchange summary report.

In the event that the informal procedures do not resolve the dispute within 30 days, the dispute shall be submitted to binding arbitration as described below.

R10.5. Binding Arbitration. A professional arbitration service will provide each of the parties in the dispute an opportunity to be heard. Within 30 days of those presentations, the arbitrator shall issue a decision. The decision and the rationale for the decision shall be provided in writing to the disputing parties, the operating committee, and the NERC compliance manager.

R11. Each balancing authority shall participate in automatic time error correction unless it is operating asynchronously to its Interconnection. *Reference Standard BAL-004, Time Error Correction.*

R12. Each balancing authority shall perform an area interchange error (AIE) survey as requested by the NERC operating committee to determine the balancing authority's interchange error(s) due to equipment failures, improper scheduling operations, or improper AGC performance.

Inadvertent Interchange On- and Off-Peak Periods

Note: It is currently intended to leave the On- and Off-Peak definition in the NAESB Business Practices. The following requirements are included here for reference only.

R13. The hourly inadvertent energy accumulated by a balancing authority is classified as either On-Peak or Off-Peak inadvertent interchange. The peak designation assigned is a function of hour of day, day of week, time zone, prevailing time (standard or daylight savings), and special holiday status.

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R14. The On-Peak to Off-Peak and Off-Peak to On-Peak boundary hours are unaffected by transitions to or from daylight savings time. If a balancing authority remains on either standard or daylight savings time throughout the year, their inadvertent interchange accounting periods must be adjusted to coordinate with prevailing time used by the rest of the Interconnection.

R15. Each interconnection shall have a reference time zone and standardized On-Peak and Off-Peak periods. On-Peak periods are summarized in the table below for each interconnection. Sundays and special holidays are designated to be Off-Peak periods for the entire day. Hours for Monday through Saturday that are not shown in the table below are also designated as Off-Peak hours.

Interconnection	**Reference Time Zone**	***Hour Ending***	
		From	***To***
Eastern	Central	0700	2200
ERCOT	Central	0800	2200
Western	Pacific	0700	2200

R16. Six U.S. holidays shall be recognized as Off-Peak hours for the entire day. If any of these holidays fall on a Sunday, the following Monday will be considered an Off-Peak day. Otherwise, the Off-Peak day will be the holiday itself.

New Year's Day

Memorial Day

Independence Day

Labor Day

Thanksgiving Day

Christmas Day

G. Measures

M1. Each balancing authority shall enter net scheduled interchange and net actual interchange values with each of its adjacent balancing authorities into the NERC operating committee designated inadvertent interchange electronic application by the 15th day of the following month.

M2. Each balancing authority shall resolve all disputed interchange values with its adjacent balancing authorities within 60 days after NERC has posted the disputed interchange quantities.

M3. NERC staff will post the disputed interchange quantities by the 22nd day of the following month and publish reconciled inadvertent interchange summaries by the end of the following month.

H. Compliance

1. Compliance Monitoring Process

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1.1. Each balancing authority shall post a monthly accounting of all Net Actual interchange and net scheduled interchange with all adjacent balancing authorities, in MWh, to the NERC designated website. These postings shall not include any after-the-fact changes that were not agreed to by the source balancing authority, sink balancing authority and all intermediate balancing authority(ies).

1.2. Each balancing authority shall post its monthly interchange values with adjacent balancing authorities by the 15th calendar day of the following month.

1.3. Each regional compliance manager shall monitor the monthly inadvertent interchange summaries on the NERC designated website and the all-time accumulated inadvertent interchange.

1.4. The NERC compliance staff shall submit a monthly accounting to regional compliance managers by the 22nd day following the end of the month being summarized.

1.5.

2. Levels of Non Compliance

A balancing authority that neither posts its interchange quantities on the NERC designated website nor submits a report to the regional compliance manager with a reason for not posting the required data, by the 15th calendar day of the following month shall be considered non-compliant.

A balancing authority that fails to resolve any disputed interchange quantities with its adjacent balancing authorities within 60 days of NERC's posting of the disputed interchange shall be considered non-compliant.

I. Regional Differences

1. Midwest ISO and Southwest Power Pool: Use of scheduling agentss

1.1. The use of scheduling agents is permitted with the following provisions:

R1.1.1. The scheduling agent acts on behalf of its participating balancing authorities with all adjacent balancing authorities with respect to implementation of interchange schedules, including scheduling, confirmation, and after-the-fact checkout.

R1.1.2. The scheduling agent is included in the scheduling path of all interchange transactions with its participating balancing authorities effectively placing the scheduling agent in the role of an intermediary control area with respect to interchange transaction management.

R1.1.3. The scheduling agent manages any "scheduling error" attributable to the scheduling agent and internalizes this scheduling error into the inadvertent interchange accounts of its participating balancing authorities.

R1.1.4. The scheduling agent may be included in the reporting of net scheduled interchange in inadvertent interchange reporting similar to an intermediary control area.

R1.1.5. The scheduling agent's inadvertent interchange account shall reflect the scheduling agent's zero imbalance with the interconnection. In order to accomplish this, the scheduling agents shall add equal and opposite schedules with the scheduling agent's adjacent scheduling entities after the settlement. The net of these settlement schedules shall be zero, as any scheduling agent imbalance is allocated to its balancing authorities per I.1.1.3.

R1.1.6. Financially settled inadvertent would be removed from the appropriate balancing authorities' balances. The scheduling agent inadvertent account

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would reflect the net scheduling agent imbalance with the Interconnection. In order to accomplish this, the scheduling agent would add "equal and opposite" schedules with its participating balancing authorities after the settlement. The net of these "settlement" schedules will be zero.

R1.1.7. The Midwest ISO scheduling agent will report its inadvertent interchange balance to ECAR. Scheduling agent reporting will be consistent with the requirements and timelines for balancing authorities outlined Section F, above. In addition, the scheduling agent will maintain records of inadvertent interchange financially settled with each control area and will provide AIE data (pre and post settlement) for any surveys or formal data requests.

R1.1.8. The scheduling agent will manage and pay back its net Inadvertent Interchange balance following NERC policy. Inadvertent payback will be initiated based on an objective and publicly available process that is triggered on balances exceeding statistical norms (allows normal "breathing" of balances). Inadvertent payback will be done during periods and in amounts such that payback will not burden others or interfere with time corrections. Financial gain will not factor into the decision to payback or recover inadvertent interchange

Scheduling Agent. A function with the authority to act on behalf of one or more balancing authorities for interchange schedule implementation including creation, confirmation, approval, check-out and associated Inadvertent Interchange accounting.

Version History

Version	Date	Action	Change Tracking

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NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL

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

Area Interchange Error Monitoring Application Scope Statement

General

Project Name: Area Interchange Error Monitoring Application

Project Number: 2000-04

Project Manager: Brian Nolan

Date Submitted: November 7, 2005

Requestor Information

Primary Contact: RS Inadvertent Interchange TF Chairman Don Badley, don@nwpp.org ((503) 464-2805

Resources Subcommittee Chairman Terry Bilke, tbilke@midwestiso.org (317) 249-5463

Resources Subcommittee Secretary Tom Vandervort tom.vandervort@nerc.net (609) 452-8060

Project Statement of Need

I. There is a need for operational tools that enhances the reliability coordinators and balancing authorities' ability to quickly assess the adequacy of supply and demand as well as monitor and track the control performance of a balancing authority, within a competitive electricity market. The frequency performance of an interconnection is one of the few fundamental indicators of interconnection reliability that is universally available to all stakeholders. When the frequency performance of an interconnection deteriorates it is imperative that the reliability coordinators be able to quickly and with confidence identify the cause of the deterioration and take swift action to remedy the situation. A process of developing hourly Area Interchange Error (AIE) for each balancing authority will establish an interconnection-wide means for accomplishing this goal.

The AIE survey, as required by NERC Operating Reliability Standard BAL-006-0, Inadvertent Interchange, D.1.4, is a powerful tool for identifying imbalances between generation and load, as corrected for frequency support, among the various balancing authorities of an interconnection. However, the current AIE survey is not automated and takes months to complete.

II. In response to frequency deterioration that occurred in late July 1999, the NERC Operating Committee in its November 22, 1999 meeting passed a resolution:

> "NERC shall monitor and collect real time Area Control Error information through the Regional Councils or their Security Coordinators (Reliability Coordinators) for all Control Areas (Balancing Authorities), effective May 1, 2000."

The specific concern of the Operating Committee was to identify balancing authorities that cause large or long-term frequency deviations. The Resources Subcommittee was asked to enhance the Area Control Error information as necessary to achieve the subcommittee's goal of proper control. Hourly AIE is such a solution.

III. U.S.-Canada Power System Outage Task Force "Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations" contains these recommendations that this project will address:

Recommendation 10: Establish an independent source of reliability performance information.

Area Interchange Error Monitoring Application will supply objective, factual information (hourly AIE surveys) that will allow the reliability coordinators to perform compliance monitoring with current and future NERC reliability standards for each of the balancing authorities under their jurisdiction, identify trends in near-real-time, and take appropriate action.

Recommendation 13: DOE should expand its research programs on reliability-related tools and technologies.

Area Interchange Error Monitoring Application project development has been funded by the Department of Energy (DOE) which endorses the project. To make the Area Interchange Error Monitoring Application tool effective all balancing authorities will be required to submit hourly data.

Recommendation 22: Evaluate and adopt better real-time tools for operators and reliability coordinators.

The Resources Subcommittee recommends the Area Interchange Error Monitoring Application in order to give the reliability coordinators a reliability tool to improve their situational awareness by effectively monitoring and analyzing wide-area performance and compliance with NERC standards; and the Resources Subcommittee a reliability tool to evaluate balancing authorities compliance with AIE standards, and monitor, trend, and analyze system behavior at different levels: NERC, Interconnection, RTO, regional reliability councils, reliability coordinators, and balancing authorities.

Recommendation 35: Implement controls to manage system health, network monitoring, and incident management.

The Area Interchange Error Monitoring Application will support the reliability coordinator and balancing authority to detect EMS, IT, and scheduling errors. Hourly AIE is a series of calculations performed hourly to determine if a balancing authority performs within acceptable boundaries within a given hour and allows reliability coordinators in an interconnection to monitor, measure, track and determine in a timely manner which balancing authority is responsible for deviations away from scheduled frequency.

Project's Product

Area Interchange Error Monitoring Application Product: Software, hardware and the infrastructure specifications to produce hourly AIE surveys and analytical support data

Hourly AIE data submittal will allow reliability coordinators, the Resources Subcommittee, and other bulk electric system technical monitors to perform near-real-time AIE surveys. These AIE surveys will not be 100% accurate until the data is validated by each balancing authority within the respective interconnection. The AIE survey will be accurate enough to give the reliability coordinators the situational awareness needed for critical operation of the interconnection's frequency.

Specifically, the Consortium for Electric Reliability Technology Solutions (CERTS) Area Interchange Error Monitoring Application software will include:

- Automatic data input process to allow Control Areas to automatically input the following hourly data:

  NI_A – Integrated Net Actual Interchange with each adjacent Control Area
  NIS – Integrated Net Scheduled Interchange with each adjacent Control Area
  FB – Control Area Frequency Bias
  FA – Integrated Actual Interconnection Frequency
  FS – Average Scheduled Interconnection Frequency
  BIP – Bilateral Inadvertent Payback with each adjacent Control Area (If necessary)
  UIP – Unilateral Inadvertent Payback (If necessary)

- Database processing infrastructures
- Multi-View, Geo-Graphic visualization monitoring displays, which contain hourly, daily, and monthly data on 3D and 2D maps for each operational jurisdiction
- Tabular displays to allow schedulers to edit the data they have transferred automatically
- Event replay function

Project Deliverables

In Scope

NERC establish standards requirements for all balancing authorities to submit validate, and correct hourly data to satisfy the Area Interchange Error Monitoring Application specifications.

The Area Interchange Error Monitoring Application will provide to the Balancing Authorities a secure web site and data entry form that allows the Balancing Authority to submit, validate, and change the required hourly data.

NERC shall provide to the balancing authorities a secure FTP site that accepts data in a required format.

NERC shall provide to the balancing authorities, in accordance with reliability standard's dispute resolution compliance requirements, a view of the disputed data to assist in the dispute resolution.

The Area Interchange Error Monitoring Application will provide the Resources Subcommittee weekly reports including disputed data.

NERC shall support the Area Interchange Error Monitoring Application data flow through the necessary hardware: Ethernet connection, an ICCP node, a FTP server, a SQL server, an Application server, and a Web server.

Area Interchange Error Monitoring Application shall provide to the reliability coordinators, Resources Subcommittee, and other bulk electric system technical monitors; the actual submitted data, geographic and graphic views to facilitate the analysis of the data, analysis reports, frequency error reports, and data validation reports.

Access to the Area Interchange Error Monitoring Application shall be password protected based on registered user IDs and passwords. Area Interchange Error Monitoring Application shall be accessible to all reliability coordinators, balancing authorities, Resources Subcommittee members, and other bulk electric system technical monitors.

Out of Scope

NERC Resources Subcommittee shall review current reliability standards and submit SAR(s) as necessary that specify standards requirements for all balancing authorities to submit, validate, and correct hourly data to satisfy the hourly AIE survey requirements.

NERC Resources Subcommittee shall review current reliability standards and submit SAR(s) as necessary that specify balancing authority's standard dispute resolution requirements to address and resolve balancing authorities disputed data; non-reporting by balancing authorities; error reports by balancing authorities.

Each balancing authority will determine its methodology to submit the hourly data to NERC. This may range from manual data entry to an automated process utilizing software that links EMS to the Area Interchange Error Monitoring Application.

The AIE processes and sub processes related to resolve data problems, often referred to as data quality problems, are NERC's responsibilities and those processes are not part of the Area Interchange Error Monitoring Application process.

Assumptions

NERC will specify and require confidentiality agreements and non-disclosure agreements to individuals and companies involved in the Area Interchange Error Monitoring Application project, reliability coordinators, balancing authorities, resources subcommittee members, and other bulk electric system technical monitors.

Project Objectives

I. Reliability Objective: Satisfy the need for operational tools that enhances the reliability coordinators and balancing authorities' ability to quickly assess the adequacy of supply and demand as well as monitor and track the control performance of a balancing authority within a competitive electrical market. The Area Interchange Error Monitoring Application supports NERC's Operating Committee and Resources Subcommittee's needs for identifying balancing authorities that cause large or long-term frequency deviations in each NERC interconnection.

   Core Objective: Identify balancing authorities that cause large or long-term deviation in each NERC interconnection.

II. Reliability Objective: Satisfy the NERC Operating Committee's intent to establish a reliability tool that evaluates balancing authorities' performance and compliance with AIE standards, monitors, trends, and analyzes system behavior at different levels: NERC, Interconnection, RTO, regional reliability councils, reliability coordinators, and balancing authorities. Compliance with AIE reliability standards requirements must be mandatory throughout each interconnection.

   Core Objective: Identify balancing authorities that are non-compliant with proposed reliability standard's hourly AIE survey requirements.

III. Reliability Objective: Satisfy the U.S.-Canada Power System Outage Task Force (that investigated the causes of the August 14, 2003 blackout) recommended actions to minimize the likelihood and scope of similar events in the future.

   Core Objective: Implement Area Interchange Error Monitoring Application project to partially satisfy U.S.-Canada Power System Outage Task Force recommendations.

Cost Objectives

Area Interchange Error Monitoring Application development: Department of Energy has funded CERTS to develop the application through the implementation and validation phases.

NERC Area Interchange Error Monitoring Application hardware and support server systems: Much of the required hardware and support server systems are in place without additional expense. Additional hardware and server systems that will be procured should be less than $100,000.

Balancing Authority hourly data input: Each balancing authority will determine the methodology it will use to submit the hourly data to satisfy the Area Interchange Error Monitoring Application specifications. As an example of strictly manpower expense, manual data entry will require manpower to gather, input, validate, resolve disputes, and change data for each hour of each day. As an example of automated data entry expense, the initial expense will be to procure software that populates the AIE form with data from an EMS system, with manpower to validate, resolve disputes, and change data for each hour of each day. Hourly data entry in either example has a cost that is not determined in this scope.

NERC On-going expense for CERTS Support, Maintenance and Field Trial Participation: estimated to be $10,000 per year, starting in 2006.

Schedule Objectives

Start: Four Regions represented in the NERC Resources Subcommitee are in the process of field testing the Area Interchange Error Monitoring Application using actual sample data supplied by the WECC interconnection.

Area Interchange Error Monitoring Application Milestone Objectives:

Operating Committee endorsement

SAR submittals to incorporate AIE hourly data submittal into reliability standard

Approval and implementation of AIE hourly data submittal reliability standard

Implementation of Area Interchange Error Monitoring Application in each interconnection

Satisfactory CERTS final factory test

Each interconnection's balancing authorities hourly data input grace period

Identification and resolution of identified project problems

Actual implementation within NERC standards compliance program

Project Completion: Project completion will be six months after the actual implementation of the Area Interchange Error Monitoring Application within NERC standards compliance program.

Quality Measures

- Satisfactory testing of the integrated systems including both NERC servers and reliability coordinator clients.
- Satisfactory testing of system performance and stability, verifying the web-visualization response for clients located in different geographical locations.

- Survey five to six reliability coordinators for feedback about control monitoring system functionality, visualization and performance. NERC/CERTS will define what changes will be considered for implementation before final system delivery.

Other Objectives

None identified

Methodology

The Resources Subcommittee will work with CERTS to implement, test, incorporate constructive changes, and validate incremental results through the entire project. This working relationship has proved successful in the development and implementation of past projects: ACE-Frequency Monitoring; and the SPP Inadvertent Interchange Tool migration to NERC Inadvertent Interchange Tool.

The Operating Committee in conjunction with the Resources Subcommittee will work with the regions to gain support for the Area Interchange Error Monitoring Application project. This will include the incorporation of AIE hourly data submittal requirements into the NERC reliability standards.

Impacts/Risks

Existing Systems or Other Projects

This project has received attention from NERC operations staff, reliability assessment staff, projects staff, compliance staff and the information technology staff. NERC internal resources to support the Area Interchange Error Monitoring Application project need to be committed by each department.

Standards

BAL-006-0, Inadvertent Interchange,

> D.1.4. Each Balancing Authority shall perform an Area Interchange Error (AIE) Survey as requested by the NERC Operating Committee to determine the Balancing Authority's Interchange error(s) due to equipment failures or improper scheduling operations, or improper AGC performance.

This standard will be drafted to specify each balancing authority shall submit hourly data to produce near-real-time AIE surveys, including requirements, measures, and compliance monitoring, and levels of non-compliance. The SAR will be submitted in accordance with the NERC Standards Process Manual.

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL

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

CPS1 – BAAL Wide-Area Alarming, Monitoring and Tracking Application Scope Statement

General

Project Name: CPS1 - BAAL Monitoring Application

Project Number: 2001-38

Project Manager: Brian Nolan

Date Submitted: November 7, 2005

Requestor Information

Primary Contact: RS Frequency TF Chairman Raymond Vice, rlvice@southernco.com (205) 257-6209

Resources Subcommittee Chairman Terry Bilke, tbilke@midwestiso.org (317)2495463

Resources Subcommittee Secretary Tom Vandervort tom.vandervort@nerc.net (609)4528060

Project Statement of Need

I. There is a need for operational tools that enhance the reliability coordinators and balancing authorities' ability to quickly assess the adequacy of supply and demand as well as monitor and track the control performance of a balancing authority according to new standards. The existing control performance CPS1 provides a statistically-bound one-minute ACE performance characteristic. The existing CPS2 performance metric will be replaced by a frequency sensitive balancing authority ACE limits (BAAL) which is under field trial test. CPS1 and BAAL together will make a compact and powerful long and short term pair of balancing standards.

This operation tool will: alarm when the balancing authority's ACE performance exceeds or violates CPS1 or BAAL pre-define thresholds, track and monitor in real time the balancing authority's behavior from a wide-area perspective, facilitate reliability coordinators to define and implement remedial actions to mitigate abnormal system conditions.

Alarming, monitoring and tracking features of CPS1 and BAAL will complement the utilization of the ACE-Frequency tool for the reliability coordinators. By making the new short and long term performance metrics easily available to the reliability coordinators, it will help them to have a wide-area, more realistic view of their jurisdictions load-generation balance and control performance.

II. U.S.-Canada Power System Outage Task Force "Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations" contains these recommendations that this project will address:

Recommendation 10: Establish an independent source of reliability performance information.

Real Time alarming, monitoring and tracking of CPS1 and BAAL will supply objective, wide-area information that will allow the reliability coordinators to perform compliance monitoring with current and future NERC reliability standards for each of the balancing authorities under their jurisdiction, identify trends in near-real-time, and take appropriate action.

Recommendation 13: DOE should expand its research programs on reliability-related tools and technologies.

The CPS1 and BAAL real time monitoring project development has been funded by the Department of Energy (DOE) which endorses the project. The same data used by the ACE-Frequency monitoring application will be required in 1-minute increments.

Recommendation 22: Evaluate and adopt better real-time tools for operators and reliability coordinators.

The Resources Subcommittee recommends real time alarming, monitoring and tracking of CPS1 and BAAL Application in order to give the reliability coordinators a reliability tool to improve their situational awareness by effectively monitoring and analyzing wide-area performance and compliance with NERC standards; and the Resources Subcommittee a reliability tool to evaluate balancing authorities compliance with current and future reliability performance standards, and monitor, trend, and analyze system behavior at different operational levels: NERC, Interconnection, RTO, regional reliability councils, reliability coordinators, and balancing authorities.

Project's Product

CPS1 - BAAL Alarming, Monitoring and Tracking Application Product: Software, hardware and the infrastructure specifications to produce real-time CPS1 - BAAL multi-view, geo-Graphic, Wide-Area Visualization and data collection for analytical support purposes.

CPS1 - BAAL data allow reliability coordinators, the Resources Subcommittee, and other bulk electric system technical monitors to monitor and track in real-time the CPS1 and BAAL reliability performance metrics. The CPS1 - BAAL monitor will be accurate enough to give the reliability coordinators the situational awareness needed for taking corrective actions if the interconnections frequency and the BA's ACE exceed its ACE safe limits. The requirement for alarming when the BA's ACE exceeds or violates their BAAL for specific periods of time will allow balancing authority's to control their ACE in a way that limits adverse impact on the interconnection's frequency.

Specifically, the Consortium for Electric Reliability Technology Solutions (CERTS) CPS1/BAAL Monitoring Application software will include:

- Database processing infrastructures
- Multi-View, Geo-Graphic Wide-Area visualization displays, which contain 1-minute, hourly, daily, and monthly data on 3D and 2D maps
- Visuals showing CPS1 and BAAL performance at different jurisdictional levels from balancing authorities to interconnection
- Event replay function
- User interactive data collection capabilities to recall archived CPS1 and BAAL data

Project Deliverables

In Scope

NERC already has established standards requirements for all balancing authorities to submit 1-minute ACE and frequency data that the ACE-Frequency application currently uses. CPS1 – BAAL Monitoring Application require the same input data.

NERC shall support CPS1 - BAAL Monitoring Application data flow through the necessary hardware: Ethernet connection, an ICCP node, a FTP server, a SQL server, an Application server, and a Web server.

CPS1 - BAAL Alarming, Monitoring and Tracking Application shall be password protected based on registered user IDs and passwords. CPS1 - BAAL Monitoring Application shall be accessible to all reliability coordinators, balancing authorities, Resources Subcommittee members, and other bulk electric system technical monitors.

Out of Scope

None identified

Assumptions

NERC will specify and require confidentiality agreements and non-disclosure agreements to individuals and companies involved in the CPS1 - BAAL Alarming, Monitoring and Tracking Application project, reliability coordinators, balancing authorities, resources subcommittee members, and other bulk electric system technical monitors.

Project Objectives

Reliability Objective: Satisfy the need for operational tools that enhances the reliability coordinators and balancing authorities' ability to quickly assess the adequacy of supply and demand as well as monitor and track the control performance of a balancing authority within a competitive electrical market. The CPS1 - BAAL Alarming, Monitoring and Tracking Application supports NERC's operating committee and resources subcommittee's need for balancing authorities to control their ACE in a way that limits adverse impact on the interconnection's frequency.

Core Objective: The ultimate goal is to perform real-time alarming, monitoring, and tracking of each balancing authority's ACE with respect to BAAL to maintain situational awareness and status, and identify the root causes for the abnormalities of the NERC reliability standards.

Cost Objectives

CPS1 - BAAL Alarming, Monitoring and Tracking Application development: Department of Energy has funded CERTS to develop the application through the implementation and validation phases.

NERC CPS1 - BAAL Monitoring Application hardware and support server systems: Much of the required data communications, hardware and support server systems are in place without additional expense. Additional hardware and server systems that will be procured should be less than $100,000.

NERC On-going expense for CERTS Support, Maintenance and Field Trial Participation: estimated to be $10,000 per year, starting in 2006.

Schedule Objectives

Start: CERTS is in the process of testing the CPS1 - BAAL Alarming, Monitoring and Tracking Application using actual sample data.

CPS1 - BAAL Monitoring Application Milestone Objectives:

Operating Committee endorsement

Implementation of CPS1- BAAL Alarming, Monitoring and Tracking Application

Satisfactory CERTS final factory test

Identification and resolution of identified project problems

Actual implementation within NERC standards compliance program

Project Completion: Project completion will be six months after the actual implementation of the CPS1/BAAL Monitoring Application within NERC standards compliance program.

Quality Measures

- Satisfactory testing of the integrated systems including both NERC servers and reliability coordinator clients.
- Satisfactory testing of system performance and stability, verifying the web-visualization response for clients located in different geographical locations.
- Survey five to six reliability coordinators for feedback about control monitoring system functionality, visualization and performance. NERC/CERTS will define what changes will be considered for implementation before final system delivery.

Other Objectives

None identified

Methodology

The Resources Subcommittee will work with CERTS to implement, test, incorporate constructive changes, and validate incremental results through the entire project. This working relationship has proved successful in the development and implementation of past projects: ACE-Frequency Monitoring; and the SPP Inadvertent Interchange Tool migration to NERC Inadvertent Interchange Tool.

The Operating Committee in conjunction with the Resources Subcommittee will work with the regions to gain support for the CPS1 - BAAL Alarming, Monitoring and Tracking Application project.

Impacts/Risks

Existing Systems or Other Projects

This project has received attention from NERC operations staff, reliability assessment staff, projects staff, compliance staff and the information technology staff. NERC internal resources to support the CPS1 - BAAL Alarming, Monitoring and Tracking Application project need to be committed by each department.

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL

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

NERC Frequency Monitoring and Analysis Application Using Phasor Measurements Scope Statement

General

Project Name: NERC Frequency Monitoring and Analysis Application

Project Number: to be assigned

Project Manager: Brian Nolan

Date Submitted: October 7, 2005

Requestor Information

Primary Contact: RS Frequency TF Chairman Raymond Vice, rlvice@southernco.com (205) 257-6209

Resources Subcommittee Chairman Terry Bilke, tbilke@midwestiso.org (317)249-5463

Resources Subcommittee Secretary Tom Vandervort tom.vandervort@nerc.net (609)452-8060

Project Statement of Need

I. There is a need for monitoring and tracking tools that enhance the resources subcommittee, reliability coordinators and balancing authorities' ability to quickly assess the adequacy of supply and demand as well as recommend preventive actions to maintain reliability within a competitive electricity market. The frequency performance of an interconnection is one of the few fundamental indicators of interconnection reliability that is universally available to all stakeholders. When the frequency performance of an interconnection deteriorates it is imperative that NERC subcommittees be able to quickly and with confidence identify the cause of the deterioration and take preventive actions to remedy the situation. An application using multiple-sources of time-synchronized accurate frequency data, with interactive data collection, analysis, and report capabilities will facilitate NERC subcommittees to accomplish timely frequency abnormalities analysis, assessments and recommendations.

II. The U.S.-Canada Power System Outage Task Force "Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations" contains these recommendations that this project will address:

Recommendation 10: Establish an independent source of reliability performance information.

Frequency Monitoring and Analysis Application will supply objective, factual information that will allow the resources subcommittee to monitor and track the Eastern Interconnection frequency.

Recommendation 22: Evaluate and adopt better real-time tools for operators and reliability coordinators.

The resources subcommittee recommends the Frequency Monitoring and Analysis Application in order to obtain a reliability tool to evaluate balancing authorities' compliance with AIE standards, and monitor, trend, and analyze system behavior at different levels: NERC, interconnection, RTO, regional reliability councils, reliability coordinators, and balancing authorities.

Recommendation 28: Require use of time-synchronized data recorders

In its requirements of February 10, 2004, NERC directed the regional councils to define within one year regional criteria for the application of synchronized recording devices in key power plants and substations.

A valuable lesson from the August 14, 2003 blackout is the importance of having time-synchronized system data recorders. The task force's investigators labored over thousands of data items to determine the sequence of events, much like putting together small pieces of a very large puzzle. That process would have been significantly faster and easier if there had been wider use of synchronized data recording devices.

NERC Planning Standard I.F., Disturbance Monitoring, requires the use of recording devices for disturbance analysis. On August 14, 2003 time recorders were frequently used but not synchronized to a time standard.

Project's Product

The Consortium for Electric Reliability Technology Solutions (CERTS) Frequency Monitoring and Analysis application will include:

- Automatic transmission of phasor frequency data from a minimum of three different locations in the Eastern Interconnection using the EIPP phasor data.
- Synchronization of the frequency sampling intervals, time stamp information and any other time information required (calibrated to sources traceable to the National Institute of Standards and Technology (NIST) time standards).
- Collection and archive frequency data to a resolution of at least +/-0.001 Hertz (one milliHertz).
- Store archived frequency data at a minimum rate of one sample per second, with a resolution no less than the specified accuracy of the associated frequency transducer.
- Maintain on-line archived frequency data for a minimum of five (5) years.
- Support report production and database query capabilities that offer standard periodic reports and event driven reports using archived data.
- Support database query and report writing tools to generate both graphic and tabular format reports.
- Wide-Area graphical visuals to quickly correlate frequency abnormalities with specific operational jurisdictions.
- Allow only authorized users to view and query the frequency database content

Project Deliverables

In Scope

This application will use the Eastern Interconnection Phasor Project (EIPP) phasor infrastructure with TVA serving as the host for Eastern Interconnection frequency data source, both for real time and for archived phasor frequency data. NERC shall support the application data flow through the necessary hardware: Ethernet connection, an ICCP node, a FTP server, a SQL server, an Application server, and a Web server.

The Application shall be password protected based on registered user IDs and passwords. Frequency Monitoring and Analysis Application shall be accessible to the resources subcommittee members.

Out of Scope

None identified

Assumptions

NERC will specify and require confidentiality agreements and non-disclosure agreements to individuals and companies involved in the Frequency Monitoring and Analysis.

Project Objectives

Primary Objective: A reliability tool to evaluate balancing authorities' compliance with control performance and AIE standards, and monitor, trend, and analyze system behavior at different levels: NERC, interconnection, RTO, regional reliability councils, reliability coordinators, and balancing authorities.

For this project the fundamental metrics utilize the Eastern Interconnection frequency in order to support the NERC's resource subcommittee's need to identify the root cause for the abnormalities of reliability performance standards. The time error correction (TEC) data will be required.

Cost Objectives

Frequency Monitoring and Analysis Application development: Department of Energy has funded CERTS to develop the functional specification and initial software development, and CERTS is requesting additional funding to complete the application software component of the project.

NERC Frequency Monitoring and Analysis application hardware and support server systems: Much of the required data communications, hardware and support server systems are in place without additional expense. Additional hardware and server systems that will be procured should be less than $100,000.

NERC On-going expense for CERTS Support, Maintenance and Field Trial Participation: estimated to be $30,000 per year, starting in 2006.

Schedule Objectives

Start: August 2005 – Functional Specifications

October 2005 – Start software development

Frequency Monitoring and Analysis Application Milestone Objectives:

- Functional Specification
- Resources Subcommittee approval
- Operating Committee endorsement
- Implementation of Frequency Monitoring and Analysis Application
- Satisfactory CERTS factory test
- Satisfactory NERC-CERTS field test
- Actual implementation within NERC standards compliance program

Project Completion: Second Quarter 2006

Quality Measures

- Satisfactory testing of the integrated systems including both NERC servers and reliability coordinator client.
- Satisfactory testing of system performance and stability, verifying the web-visualization response for client.

Other Objectives

None identified

Methodology

The resources subcommittee will work with CERTS to implement, test, incorporate constructive changes, and validate incremental results through the entire project. This working relationship has proved successful in the development and implementation of past projects: ACE-Frequency Monitoring; and the SPP Inadvertent Interchange Tool migration to NERC Inadvertent Interchange Tool.

Impacts/Risks

Existing Systems or Other Projects

This project has received attention from NERC operations staff, reliability assessment staff, projects staff, compliance staff and the information technology staff. NERC internal resources to support the Frequency Monitoring and Analysis Application project need to be committed by each department.

Source of phasor input data for the project will be coming from TVA master phasor database. TVA resources commitment to work with CERTS and NERC with the input phasor data is required.