BOARD OF TRUSTEES MEETING

February 11, 2003 — 8 a.m.–1 p.m.
Ritz-Carlton Phoenix
2401 East Camelback Road
Phoenix, Arizona
602-468-0700

AGENDA

Introductions and Chairman’s Remarks

Antitrust Statement

Consent Agenda
1. Stakeholders Committee and Standing Committees Membership Changes — Approve
2. Review of Minutes — Approve
   a. October 8, 2002 Meeting
   b. November 4, 2002 Action Without a Meeting
   c. November 12, 2002 Conference Call
   d. November 15, 2002 Action Without a Meeting
   e. November 27, 2002 Conference Call
   f. December 6, 2002 Conference Call
   g. January 27, 2003 Action Without a Meeting
3. Future Meetings — Approve
4. Revisions to Existing Operating Policies — Approve
5. Hotline — Conference Bridge Project — Approve
6. Elections and Appointments
   a. Election of Officers — Approve
7. Stakeholders Committee Report
8. Strategic Plan 2003–2006 — Approve
9. Recommendations on the Role of the Standing Committees — Approve
10. **Review of Interdependency Between Gas Transportation and Electric Generation: Scope** — **Approve**

11. **Compliance Enforcement Program**
   a. Request for Regional Verification Mechanisms for Operating Security Limit Violations — **Approve**
   b. Reliability Coordinator Audit Program
   c. Request for Reports on Regional Compliance and Enforcement Programs — **Approve**
   d. 2003 Compliance Enforcement Program

12. **Critical Infrastructure Protection**
   a. CIPAG Scope and Organization Transition Plan — **Approve**
   b. CIPAG Report

**BREAK**

13. **PJM-MISO Evaluation**

14. **NERC-NAESB-RTO Discussions**

15. **Reliability Standards**
   a. Standards Authorization Committee Report
   b. NERC-NAESB Joint Interface Committee Report
   c. Functional Model Update

**Committee Reports**

16. Finance and Audit
   a. Treasurer’s Report

17. Corporate Governance and Nominating
18. Human Resources and Compensation

**Informational Items**

19. Legislation
20. FERC Rulemakings
   a. Standard Electricity Market Design
   b. Standardization of Small Generator Interconnection Agreements and Procedures
21. Standing Committee Reports
   a. [Market Interface Committee](#)
   b. [Operating Committee](#)
   c. [Planning Committee](#)
NERC ANTITRUST COMPLIANCE GUIDELINES

I. GENERAL

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

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

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

II. PROHIBITED ACTIVITIES

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

- Discussions involving pricing information, especially margin (profit) and internal cost information and participants’ expectations as to their future prices or internal costs.

- Discussions of a participant’s marketing strategies.

- Discussions regarding how customers and geographical areas are to be divided among competitors.

- Discussions concerning the exclusion of competitors from markets.

- Discussions concerning boycotting or group refusals to deal with competitors, vendors or suppliers.
III. ACTIVITIES THAT ARE PERMITTED

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

You should also ensure that NERC procedures, including those set forth in NERC’s Certificate of Incorporation and Bylaws are followed in conducting NERC business. Other NERC procedures that may be applicable to a particular NERC activity include the following:

- Transitional Process for Revising Existing NERC Operating Policies and Planning Standards
- Organization and Procedures Manual for the NERC Standing Committees
- System Operator Certification Program

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

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

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

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

Any other matters that do not clearly fall within these guidelines should be reviewed with NERC’s General Counsel before being discussed.

Approved by NERC Board of Trustees
June 14, 2002
Stakeholders Committee and Standing Committees Membership Changes

Action
Approve recommended membership appointments.

Stakeholders Committee
The Stakeholders Committee recommends the following for appointment to the committee for one-year terms through December 31, 2003:

- **IOU** — Nicholas P. Winser, Senior Vice President, National Grid, USA
- **Small End-Use Electricity Customer** — Timothy D. Hay, Chief Deputy Attorney General, Office of the Attorney General, Bureau of Consumer Protection

Standing Committees
With the future roles of the NERC standing committees under review, the NERC Board at its June 2002 meeting extended the terms of the members of the three committees to June 30, 2003. Due to turnover in the membership of the committees, the Board is requested to approve the recommended member appointments shown below for terms through June 30, 2003.

Recommended Membership Appointments to NERC Standing Committees

<table>
<thead>
<tr>
<th>Committee</th>
<th>New Member</th>
<th>Term</th>
</tr>
</thead>
<tbody>
<tr>
<td>MIC</td>
<td>Katie Kaplan (IPP) — Independent Energy Producers Association</td>
<td>6/30/03</td>
</tr>
<tr>
<td>OC</td>
<td>James A. Maenner (RRO-MAIN) — Wisconsin Public Service Corporation</td>
<td>6/30/03</td>
</tr>
<tr>
<td>OC</td>
<td>Bill Hatfield (State/Muni) — Lower Colorado River Authority</td>
<td>6/30/03</td>
</tr>
<tr>
<td>OC</td>
<td>James D. Cyrulewski (RRO-ECAR) — International Transmission Company</td>
<td>6/30/03</td>
</tr>
<tr>
<td>PC</td>
<td>George Bowden (RRO-Canada (W)) — AltaLink Management Ltd.</td>
<td>6/30/03</td>
</tr>
<tr>
<td>PC</td>
<td>Carmine Marcello (RRO-Canada (E)) — Hydro-One Networks Inc.</td>
<td>6/30/03</td>
</tr>
</tbody>
</table>
The voting positions on the committees shown below remain unfilled at this time. Every effort will be made to find candidates for these unfilled positions.

**Unfilled Voting Positions on NERC Standing Committees**

<table>
<thead>
<tr>
<th>Committee</th>
<th>Unfilled Positions</th>
</tr>
</thead>
<tbody>
<tr>
<td>MIC</td>
<td>Canada</td>
</tr>
<tr>
<td>PC</td>
<td>Customer</td>
</tr>
<tr>
<td>PC</td>
<td>ISO/RTO</td>
</tr>
</tbody>
</table>

Due to limited staff and funding, several non-voting regulatory and industry association observer positions also remain unfilled at this time.

Once the future roles of the standing committees and their composition are determined, the membership of the committee(s) will be revisited. The Board will likely be asked at its June 2003 meeting to approve new membership appointments consistent with any restructuring of the standing committees.
Review and Approval of Minutes

Action
Approve minutes as follows:

a. October 8, 2002 Regular Meeting.
b. November 4, 2002 Action Without a Meeting (ratifying the decision of the Operating Committee to approve the revised MISO and PJM reliability plans and authorizing NERC to file with FERC the “Initial Report of the North American Electric Reliability Council” concerning the revised MISO and PJM reliability plans).
c. November 12, 2002 Conference Call (approving filing NERC’s comments in FERC’s standard market design rulemaking).
e. November 27, 2002 Conference Call (approving the adoption of the NERC-NAESB Memorandum of Understanding).
f. December 6, 2002 Conference Call (approving criteria for selection of NERC representatives to Joint Interface Committee).
Future Meetings

Action

Information
The Board has previously approved the following dates and locations for future meetings:

- June 9–10, 2003 — St. Louis, Missouri (M–T)
- October 9–10, 2003 — Washington, D.C. (Th–F)
- February 5–6, 2004 — Scottsdale, Arizona (Th–F)
Policy 3, “Interchange”
Appendix 3D, “Transaction Tag Actions”

Action
Approve

Background
Before implementing a bilateral transaction, the merchant (or whoever is setting up the “deal”) must supply a tag to inform the source, sink, and intermediary control areas, plus their respective transmission providers.\(^1\)

If one of the transmission providers (either on the path, or on a parallel path) needs to curtail this transaction because it is contributing to an overload in the transmission provider’s system, or reload the transaction after clearing an overload, Policy 3 requires that the transmission provider contact either the source or sink control area and ask the control area to adjust the tag.

The Operating Committee’s Interchange Subcommittee recommends revising the tagging rules in Policy 3 to allow the transmission provider responsible for mitigating local overloads (TP2 in the figure at right) to adjust the tag directly. This makes the transaction adjustment process quicker and more efficient.

This revision applies only to those instances where a transmission provider is using its own process, perhaps as part of its transmission tariff, to mitigate congestion. This revision does not apply to the tagging protocols under the Eastern Interconnection’s TLR procedure.

Ballot
The three standing committees (Operating Committee, Planning Committee, and Market Interface Committee) approved the Policy and Appendix changes, which they balloted for the ten-day period of January 16–25, 2003.

<table>
<thead>
<tr>
<th>Ballots</th>
<th>Votes</th>
<th>% of Vote</th>
</tr>
</thead>
<tbody>
<tr>
<td>Affirmative</td>
<td>60</td>
<td>94</td>
</tr>
<tr>
<td>Negative</td>
<td>4</td>
<td>6</td>
</tr>
<tr>
<td>Abstain</td>
<td>1</td>
<td></td>
</tr>
<tr>
<td>Total</td>
<td>65</td>
<td></td>
</tr>
<tr>
<td>Not returned (or late)</td>
<td>37</td>
<td></td>
</tr>
</tbody>
</table>

\(^1\) Under the new Reliability Standards that are based on the Functional Model, the “tag” would be sent to the interchange authority who would inform the reliability authority(ies), source and sink balancing authorities, and the transmission service providers.
Appendix 1F, “Inadvertent Interchange Dispute Resolution Process, and Error Adjustment Procedures, and On- and Off-Peak Periods”

Action
Approve

Background
Control areas record their inadvertent interchange as either “on-peak” or “off-peak,” depending on the time of day, and day of the week. Generally, the on-peak period is Monday through Saturday from hour ending 0700 (or 0800 in ERCOT) through 2200, and the off-peak period is all other times (see diagram at right). Control areas are required to repay their inadvertent interchange with “in-kind” energy — on-peak with on-peak, and off-peak with off-peak.

The Eastern and Western Interconnections also consider six specific U.S. holidays as off-peak days. If these holidays occur on Sunday, the Resources Subcommittee has found that the load shape of the following Monday tends to have an off-peak characteristic. Each fall, the subcommittee reviews these holidays for the following year and the NERC staff issues a revised appendix with the “Monday adjustments.”

This holiday characteristic has been quite consistent for many years, and the subcommittee believes a static appendix is sufficient and easier to maintain. The proposed revision is also easier to read with the on- and off-peak hours in a table format.

The designation of on- and off-peak inadvertent periods is actually a business practice, and, at NERC’s request, NAESB has included this item in its Wholesale Electric Quadrant Annual Plan for the 2nd quarter of 2003. NAESB has assigned this to its Market Operations Subcommittee.

Until the NAESB business practices are in place, NERC should continue to specify these periods.

Ballot Results
The three standing committees (Operating Committee, Planning Committee, and Market Interface Committee) approved the changes to subsection F, “On-Peak and Off-Peak Periods,” which they balloted for the ten-day period of December 9–19, 2002.

<table>
<thead>
<tr>
<th>Ballots</th>
<th>Votes</th>
<th>% of Vote</th>
</tr>
</thead>
<tbody>
<tr>
<td>Affirmative</td>
<td>63</td>
<td>100</td>
</tr>
<tr>
<td>Negative</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Abstain</td>
<td>1</td>
<td></td>
</tr>
<tr>
<td>Total</td>
<td>64</td>
<td></td>
</tr>
<tr>
<td>Not returned</td>
<td>40</td>
<td></td>
</tr>
</tbody>
</table>
Hotline — Conference Bridge Project

Action
Authorize funding and implementation plan for the Hotline — Conference Bridge Project 2001–16.

Background
This project would install a conference bridge at the NERC offices in Princeton to provide hotline capabilities between Reliability Coordinators, and to handle at least part of the growing NERC conference call requirements.

This project appears in the “pending projects” portion of the 2003 Budget under the Telecommunications & Infrastructure area. The Operating Committee has approved the need for this project and the Cost Allocation Subcommittee has reached agreement on allocating the costs among the Regions. As a “pending project,” NERC may assess the Regions for this additional funding.

A confidential copy of the project plan, including project costs, has been sent to the Board under separate cover.
Standards & Project Implementation Plan

2001-16 Hotline – Conference Bridge

Other Project Information

<table>
<thead>
<tr>
<th>Requestor</th>
<th>Reliability Coordinator Working Group (RCWG, formerly SCWG)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Request Date</td>
<td>April 19, 2000</td>
</tr>
<tr>
<td>Responsible Group</td>
<td>Telecommunications Working Group (TWG)</td>
</tr>
<tr>
<td>Sponsoring Group</td>
<td>Operating Committee (OC)</td>
</tr>
<tr>
<td>Project Manager</td>
<td>Robert Jackson</td>
</tr>
</tbody>
</table>

Date Updated: 11-21-2002

NOTE: This copy of the SPIP has cost estimates eliminated to allow for dissemination to wider audiences. Complete versions have been distributed to the Cost Allocation Subcommittee and the Finance and Audit Committee. Cost information will only be disclosed in closed session of the Board of Trustees. Entities represented in that meeting will be excluded from bidding on the project.

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E. Policy Impacts .................................................................................................................. 4
F. Resources ....................................................................................................................... 4
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A. Project Description

This project would install a conference bridge at the NERC offices in Princeton to provide hotline capabilities between Reliability Coordinators, and to handle at least part of the growing NERC conference call requirements.

Project Details

The following are the requirements for a replacement hotline system.

- Capable of dialing multiple numbers simultaneously
- Available at any time, 24 x 7 x 365
• Ability to initiate a call from any location
• Changes to the hotline can be made easily and quickly
• Ability to add in callers who are missed on initial call
• At least 24 dedicated ports which are reserved specifically for this use that cannot be shared with others

B. Justification
Providing the hotline conference bridge service to the Reliability Coordinators is directly in keeping with NERC’s mission to foster reliability, and is required for the safe and reliable operation of the system.

Today’s Preset Conference Feature Description
The Preset Conference Feature (PCF) is a Telephone Company Central Office based conference arrangement. It requires no premise equipment and can be accessed from any telephone set anywhere.

A conference (with up to 25 pre-determined conferees) is established by dialing a specific telephone number, and then entering a 4-digit directory code. An optional authorization code may also be required. The Central Office switch dials all conferees simultaneously and when the first conferee answers, the conference begins.

Often, random Reliability Coordinators are not called by the system or are not near the predetermined telephone when the call takes place. The telephone company has been unable to “fix” the problem of some phones not being called.

Background
NYISO had the local telephone company install a Preset Conference Feature (PCF) to use as a “Hot Line” for its back-up Control Center.

In 1993, billing for the NERC PCF was applied to NYISO’s account with the agreement that NYISO would re-bill NERC for the associated monthly charges. Since it was a NYISO account, NYISO staff is responsible for ordering additions or changes as well as handling troubles. NERC staff performs the weekly testing.

Operational and Procedural Considerations
As a conference call is made, each conferee answers by stating the acronym for his region’s name (NYISO, ECAR, etc.). The conference initiator quickly performed a roll call, and then proceeded with his message.

The PCF was expanded, and as a result, has become quite cumbersome as an emergency communications tool. There are too many parties answering at once and the roll call takes too long.

Administrative Concerns
The existing NERC PCF is dependent on a NYISO telecommunications facility. This arrangement is complex and leaves NERC with little control over its emergency communication system.

Also, the expansion of the Hot Line to include all Reliability Coordinators has resulted in more frequent number changes and tracking of orders which has increased NYISO staff’s administrative workload. NYISO’s desire is to transfer this responsibility to NERC staff
Summary of Concerns
The current hotline has a number of problems: that cannot be corrected or changed:

- Present Hotline is limited to maximum of 25 members
- Frequent problems are experienced on hotline calls
- Missed Calls – Once the call is dialed, if any of the parties are missed there is no way to get them back into the call.
- No Management Capabilities – NERC does not have direct management capabilities of conference groups, and changes can take 1-2 weeks to complete.
- No Call Origin Identification – The origin of each call cannot be identified.
- Number Changes can take 1 - 2 weeks to be completed through Verizon What benefits (positive impacts) do we achieve by doing this project, and for whom?

This situation cannot continue indefinitely.

Options Studied
After a protracted attempt to install a newer version of this telephone company central office based system, near the NERC office, the Telecommunication Working Group feels that there are only two remaining options; the purchase and installation of an on-premise conference system, or the use of a 24X7 conference service.

In investigating options for replacement of the hotline, the TWG tested the potential for using a conference bridge service. That testing failed and the potential vendor has since gone bankrupt. When the RCWG requested that TWG continue the investigation, the most viable option was determined to be the installation of a conference bridge at the NERC office.

TWG examined two scalable conference bridge systems: one with 48 channels and the other with 72 channels. Both are capable of expansion.

Proposed System Features
The features offered by the new conference bridge can alleviate all of the problems with the current system:

- Ability to add conferees mid call
- Flexibility
  - Expandable by owner
  - Flexible conference call size
  - Features controlled by owner
- Management of call records
  - Who Initiated & Answered Call
  - When Answered & Disconnected
- Identifies origin to person called
- Adjusts for noisy environments
C. **Project Milestones and Schedule**

The following is the projected schedule for the project.

<table>
<thead>
<tr>
<th>Task / Milestone</th>
<th>Responsible Group</th>
<th>Schedule</th>
</tr>
</thead>
<tbody>
<tr>
<td>RCWG / ORS Presentation</td>
<td>TWG</td>
<td>September 18-19, 2002</td>
</tr>
<tr>
<td>TWG Finalize Proposal</td>
<td>TWG</td>
<td>September 26-27, 2002</td>
</tr>
<tr>
<td>Cost Allocation Subcommittee Review</td>
<td>NERC Staff</td>
<td>October 7, 2002</td>
</tr>
<tr>
<td>ORS Approval (conf. Call)</td>
<td>TWG</td>
<td>October 2002</td>
</tr>
<tr>
<td>OC Approval</td>
<td>ORS</td>
<td>November 2002</td>
</tr>
<tr>
<td>BOT Approval</td>
<td>OC</td>
<td>February 2003</td>
</tr>
<tr>
<td>Installation</td>
<td>Vendor</td>
<td>March 2003</td>
</tr>
<tr>
<td>Testing &amp; Training</td>
<td>Vendor &amp; NERC Staff</td>
<td>March-April 2003</td>
</tr>
<tr>
<td>Target In-Service Date</td>
<td></td>
<td>May 1, 2003</td>
</tr>
</tbody>
</table>

D. **Related Projects**

No other projects are related to this project.

E. **Policy Impacts**

No policies are impacted by this project.

F. **Resources**

The conference bridge recommended for installation is the Consortium Conference System, offered by Forum Communications International.

The conference bridge would be installed at the NERC offices in Princeton, New Jersey. Three additional telephone IRCs (23 channels for voice, 1 channel for control) would be required to support a 72-channel system (69 channels in service).

No additional manpower is required for this project at NERC or in the Reliability Coordinator sites.

G. **Training**

Cost for in-house training NERC staff on the use, maintenance and management of the conference bridge is included in the cost estimate supplied by the recommended.

Qualified NERC staff would conduct training for new personnel in-house, based on materials supplied by the manufacturer.
H. Cost, Funding, and Cost Allocation

Cost Estimate

The costs associated with a 72-channel system are contained in the following table.

Note: Toll costs were not included in the analysis because NERC conference call participants currently incur long distance toll charges for the currently used conference call services.

<table>
<thead>
<tr>
<th>Task</th>
<th>2003 Forecast</th>
<th>2004 Forecast</th>
<th>2005 Forecast</th>
<th>Total</th>
</tr>
</thead>
</table>

*Table Intentionally Excluded for Agenda Package*

Funding and Cost Allocation

This cost estimates would result in a net increase of $_______ in budget year 2003. The Hotline project was listed as a $_______ Pending Project in the 2003 budget, under the Telecommunications sub-section of the Projects and Data Services section. If approved, those funds may be assessed of the Regions.

Subsequent operation costs would also be carried in that budget section, with annual operating costs expected to be about $_______ per year.

Although the Hotline conference bridge is being proposed primarily for use by the Reliability Coordinators, all committees of NERC will be users of the conference bridge. Funding for the conference bridge system would be on a NERC-wide basis, allocated to all ten Regions, as directed by the Cost Allocation Subcommittee.

I. Cost Benefit Analysis

Currently, NERC spends about __________ on conference calls using conference call services.

Analysis of those calls shows that key groups such as the Board of Trustees, the Finance and Audit Committee, the Technical Steering Committee, and the Electric Sector ISAC account for almost half of that conference call burden. Time-based analysis of those groups shows that they account for a maximum of 22 callers at peak times. That means that either the 48 or 72 channel systems would be sufficient to meet the hotline requirement for 24 reserved channels and still be able to support those other group calls.

For analysis purposes, it was assumed that the 48-channel system could supplant one half of the NERC conference call needs, while the 72-channel system could supplant 75%. In both cases, NERC would still need to use a 3rd party conference call vendor for larger calls or during peak times.

Both systems are expected to break even in their 5th year of operation (2007). However, with the larger 72-channel system, the possibility exists for replacing larger portions of NERC’s conference call needs.

J. Approval History

Project History

The concept of installing a conference bridge at the NERC office for the Hotline was proposed by the TWG to the RCWG in April 2000. After their investigation into the project, the TWG proposed use of a more cost-effective conference bridge service to the RCWG in November 2000. After initial testing in 2001, that service was found to be inadequate and the company offering the service went bankrupt. The project was put on hold.

In February 2002, the RCWG (then the Reliability Authority Working Group) again charged the TWG with investigating alternatives for the Hotline.
<table>
<thead>
<tr>
<th>Approving Body</th>
<th>Action/Status</th>
<th>Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cost Allocation Subcommittee</td>
<td>Approved recommended 10-Region (NEL) cost allocation.</td>
<td>10-7-02</td>
</tr>
<tr>
<td>Operation Reliability Subcommittee Executive Committee</td>
<td>Approved for recommendation to the Operating Committee</td>
<td>11-21-02</td>
</tr>
<tr>
<td>Operating Committee</td>
<td>Approved for recommendation to the Board of Trustees</td>
<td>11-21-02</td>
</tr>
</tbody>
</table>
Elections and Appointments

Action
Elect and appoint Officers of the Corporation as outlined below

Background
Article VII, Section 1 — Officers of the NERC Bylaws states:

At its regular meeting following the first Annual Meeting of Members and annually thereafter, the Board shall elect a Chairman, a Vice Chairman, a President, a Secretary-Treasurer, an Assistant Secretary Treasurer, and such other officers (collectively, the “Officers”) as it shall deem necessary. The Chairman and the Vice Chairman must each be Independent Trustees prior to their election to such offices. The Chairman, Vice Chairman, and President shall each be nominated and elected by the Board. All of the remaining Officers shall be appointed or removed by the Board based upon the recommendation of the President . . .

Election of Certain Officers
The Board will nominate and elect officers to serve through the Board of Trustees meeting following the 2004 Annual Meeting of Members that will include a Chairman, Vice Chairman, and President and CEO.

Appointment of Certain Officers
President and CEO Gent will recommend that the Board appoint certain additional officers to serve through the Board of Trustees meeting following the 2004 Annual Meeting of Members.
Strategic Plan 2003–2006

Actions

• Approve NERC Strategic Plan 2003–2006.
• Direct management to prepare a recommended Business Plan for 2004, which will include the 2004 budget.

Background

A strategic review and planning steering committee, appointed by the Board, has developed this proposed Strategic Plan 2003–2006 and recommends its approval by the Board.

The committee also recommends that the Board direct management to develop a proposed Business Plan for 2004 for consideration by the Board at its June 2003 meeting. This annual Business Plan will comprise objectives for 2004 and the 2004 budget.

Chairman Drouin has asked the Stakeholders Committee to discuss the NERC Strategic Plan at its meeting on February 10 in the presence of the Board.

The members of the steering committee are Richard Drouin, Tom Berry, Don Hodel, Mike Gent and Mike Greene.
NERC Strategic Plan — 2003–2006
FINAL DRAFT – January 15, 2003

Introduction

The Board of Trustees of the North American Electric Reliability Council (NERC) has prepared this plan to provide strategic direction and establish priorities for the future of the organization. This plan is the result of a strategic review and planning initiative begun in late 2002 involving the Board of Trustees, committee officers, senior management, and key industry and regulatory leaders.

The Board will be responsive to major challenges and trends within or affecting the bulk electric industry, and review the strategic plan annually to determine the changes needed. The Board will use the plan as a guide in preparing its annual business plan.

Purpose of the Strategic Plan

This plan summarizes NERC’s mission, vision, values and priority goals for 2003–2006, and its implementation approach. The plan serves three primary purposes:

Policy Guide — The Board will use this plan as a guide for making policy decisions.

Informational Resource — The Board and management will use this plan to inform partners and stakeholders of the essential views, values and goals of NERC.

Planning and Assessment Tool — The Board will use this plan as a guide for approving annual business plans developed by management. Management and committees will establish projects and activities that support the priority goals in this plan. The Board will use the plan to monitor and assess progress in achieving goals and objectives.

Reliability Legislation and the Strategic Plan

The Board in 1997 agreed to pursue the development of a new self-regulatory system of reliability management for the North American bulk electric system based on the recommendations contained in the report of the Electric Reliability Panel. The Board recognized that establishing this system required the enactment of new federal legislation in the United States, while sufficient legislative or regulatory authority already existed in Canada.

NERC and a broad coalition of industry, state and consumer organizations continue to press for enactment of reliability legislation in the United States Congress that would

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1 NERC Annual Business Plans will comprise annual goals, objectives, and budgets.
provide for the creation of an electric reliability organization to develop and enforce mandatory reliability rules with oversight in the United States by the Federal Energy Regulatory Commission (FERC) to make sure that it operates effectively and fairly.

The transformation from a voluntary system of reliability management into an industry-based self-regulatory system of mandatory reliability standards cannot be fully realized until the United States Congress passes authorizing legislation. When this happens, this strategic plan will be modified to reflect the form of the legislation that is passed and the new responsibilities and authorities that NERC would assume as the North American Electric Reliability Organization (NAERO.)

NERC will aggressively seek passage of reliability legislation and the associated FERC rulemaking to enable NERC to fully transform into NAERO. Once legislation is enacted, NERC will make the necessary changes to its governance, funding, membership and staff to complete its transformation. Until then, NERC will evolve consistent with the proposed NAERO model.

I. Mission

NERC’s primary commitment is to maintain its leadership role in developing and enforcing reliability standards.

The MISSION of NERC is to ensure that the bulk electric system in North America is reliable, adequate and secure.

In carrying out its mission, NERC will preserve existing strengths that are relevant to the future, and initiate actions to address new challenges to reliability. NERC will also support the evolution and establishment of competitive market practices that provide affordable electricity to customers and are consistent with reliability standards.

The Board made a critical strategic decision in February 2002 regarding the future mission of NERC. At that time, the Board decided that NERC should continue to focus on issues of bulk electric system reliability and not accept added responsibility for developing wholesale electric business practice standards. The major reason for this decision was the Board’s conviction that developing business practice standards could weaken and conflict with NERC’s role in serving the public interest by maintaining bulk electric system reliability. This decision does not mean that NERC is not concerned with the development of competitive markets. Indeed, NERC is committed to carrying out its reliability responsibilities in ways that enable and encourage market solutions to the maximum extent possible. In this regard, NERC has committed to work closely with the North American Energy Standards Board (NAESB) and others to ensure that business practice standards and reliability standards are harmonized, and that every practicable effort is made to eliminate overlap and duplication of effort in the development of these standards.
II. Vision

NERC has identified a number of measures by which its success can be judged.

The VISION of NERC is to be a trusted leader and convener of choice regarding reliability matters within the North American bulk electric industry. NERC’s success will be evidenced by:

- full and effective implementation of NERC’s standards development process;
- a strong, independent and effective program for enforcing compliance with mandatory reliability standards;
- effective advocacy for sufficient generating and transmission capacity;
- an effective program for ensuring critical infrastructure protection for the North American bulk electric systems against the threat of sabotage and terrorism;
- strong and productive relationships with other institutions to promote bulk electric system reliability; and
- high-level cooperation with the Federal Energy Regulatory Commission, state regulators and Canadian regulators.

III. Values

Organizational behavior will influence the pace and extent of NERC’s progress in achieving its priority goals. Accordingly, NERC is committed to the following values in carrying out its mission:

Independence — NERC will ensure independence and impartial judgment in its decision making.

Fairness and Balance — NERC will accord all stakeholders equal rights and privileges and ensure that the interests of industry stakeholders are balanced in the development of its policies, reliability standards and in the conduct of its programs and activities.

Inclusiveness — NERC will be an open and transparent organization and reach out to, encourage and welcome the involvement of all industry stakeholders.

Technical Excellence — NERC will promote the active participation of the best technical leaders from the industry.

Flexibility — NERC will foster organizational flexibility, be adaptive in its priority goals and be responsive to emerging challenges.
Integrity — NERC will maintain the highest levels of professional and ethical conduct, be rigorous and thorough in all it does, and strive to exceed the expectations of those it serves.

Market Solutions — NERC will proactively coordinate the development of its reliability standards with related business practice standards that enable market solutions to the maximum extent possible.

IV. Priority Goals for 2003–2006

The management philosophy of NERC is to develop clear and realistic goals based on its mission, vision and values, while also maintaining flexibility to respond to new challenges. This philosophy requires NERC to have a clear focus on its goals, realistic business plans and sufficient organizational capability, flexibility and resources to respond to the unanticipated reliability challenges that arise.

NERC has established three priority goals that will guide its development and activities for the period 2003–2006.

Goal #1: RELIABILITY LEADERSHIP — To be the recognized leader in promoting bulk electric system reliability in North America.

NERC will establish strong and effective programs to: develop, monitor and enforce reliability standards; certify reliability organizations and personnel; assess and be an advocate for adequate generation and transmission; promote physical and cyber security; and support reliable operations of the bulk electric system.

NERC will pursue its goal of reliability leadership in the following ways:

a. Complete a new system for establishing reliability standards — NERC will set standards for the reliable operation and planning of bulk electric systems through its new standards development process. This process provides for open participation and voting by industry stakeholders. NERC is seeking accreditation of its process by the American National Standards Institute (ANSI), in order to provide third-party confirmation of the fairness and suitability of the process, which will give it additional credibility in the eyes of industry stakeholders and government agencies.

In developing reliability standards, NERC will coordinate with NAESB as its wholesale electric quadrant develops related wholesale electric business practice standards. NERC and NAESB signed a Memorandum of Understanding on November 30, 2002 formalizing this coordination process. [See Goal 2.a. for more details on this coordination.]
b. **Strengthen the Compliance Enforcement Program** — NERC will reinforce its efforts to achieve compliance with its reliability standards through a combination of rewards and sanctions.

Until there is reliability legislation, NERC will establish authority for compliance enforcement through its regional contract-based compliance system.

NERC will inform leaders in the industry and government of the status of compliance with NERC standards with special attention to the most serious and chronic violations.

Although penalties and sanctions are a necessary part of the program, NERC will develop and focus attention on reward and recognition programs for good performance.

The Compliance Enforcement Program includes a Certification Program for system operators, for which NERC will seek accreditation. NERC will develop a related program to certify entities that perform the reliability functions as defined in NERC’s Functional Model.

c. **Assess and be an advocate for adequate generation and transmission** — NERC will increase and improve efforts to assess, analyze and report on bulk electric system reliability. It will seek ways to become a more effective advocate for a generation and transmission system to meet the needs of North America.

NERC will monitor present conditions on the bulk electric system, assess the performance of the system in the future and review past disturbances and other unusual operating conditions or occurrences for lessons learned.

NERC will conduct regular assessments of overall reliability in advance of the summer and winter peak demand periods, as well as annual ten-year assessments. NERC will rely on the Regional Councils to contribute data for these assessments and to provide self-assessments of reliability for their Regions.

d. **Expand efforts to foster critical infrastructure protection** — NERC will coordinate electricity industry activities to promote critical infrastructure protection of the bulk electric system in North America.

NERC will serve as the Electricity Sector’s Information Sharing and Analysis Center and work closely with the National Infrastructure Protection Center and the Office of Homeland Security.

NERC will strengthen and expand these functions as it develops an effective working relationship with the new Department of Homeland Security to ensure the protection of the bulk electricity industry’s infrastructure and coordinate with other critical infrastructure industries.
e. **Support reliable operations** — NERC will work with system operating entities throughout North America to support reliable operation of the bulk electric system, including identifying and facilitating the development and deployment of tools, data and systems needed to maintain reliability.

**Goal #2: STRONG RELATIONSHIPS** — To establish strong relationships with other institutions to promote bulk electric system reliability.

NERC will establish and maintain strong relationships to promote bulk electric system reliability by creating meaningful communication and collaboration with industry participants, stakeholder groups and regulatory authorities throughout North America.

A key to NERC’s success has been its ability to forge positive and productive relationships based upon a system of voluntary peer oversight. Today, there are growing numbers of stakeholders and stakeholder groups within the industry to which NERC must relate. The roles of some of the new entities that have been created in recent years — e.g., independent system operators, regional transmission organizations, independent transmission providers, etc. — are still evolving with respect to their reliability responsibilities. For these reasons, NERC will devote more time and effort to ensure that its relationships with all segments of the electricity industry are as positive and productive as possible. To this end, NERC will:

a. **Create a strong partnership with NAESB** — To be an effective steward of reliability interests, NERC will work closely with the organizations responsible for development of business practice standards. To achieve this objective, NERC will work in partnership with NAESB to synchronize business practices and reliability standards. To foster this collaboration, NERC has signed a memorandum of understanding with NAESB to maximize communication and cooperation and to resolve prospective disagreements.

b. **Maintain high-level communication with regulatory agencies** — NERC has good working relationships with state, provincial and federal government agencies in North America. These relationships will be redefined and strengthened as the industry transitions to a new system of mandatory reliability standards. NERC will work closely with regulatory agencies as it develops and enforces its reliability standards.

c. **Ensure positive relations with all stakeholders and stakeholder groups** — Increasingly, NERC’s activities involve interaction with individual stakeholders and stakeholder groups in addition to Regional Reliability Councils. NERC will expand communications and coordination with all stakeholders. The Board will seek advice and comments from stakeholders on matters affecting NERC’s role and performance.

d. **Coordination within Regions** — Working with Regional Councils has been a major reason for the success of NERC. Recognizing the importance of
wholehearted support and cooperation on the part of regional organizations, NERC will work to make this a strong and productive partnership, and will rely on the Regional Councils as a vehicle for obtaining the technical expertise needed for NERC’s committees and as a source of regional information.

As ISO and RTO boundaries change, it will affect the boundaries and responsibilities of existing Regional Councils. NERC will work with Regional Councils, ISOs, and RTOs to ensure that new regional boundaries are defined that promote the effective and efficient administration of reliability.

**Goal #3: EFFECTIVE ORGANIZATION** — To create the necessary levels of funding, legislative approval and organizational excellence to carry out the NERC mission.

As NERC looks forward, it must continue to change to serve the reliability interests of the bulk electric industry in North America. A partial blueprint for the development of NERC was provided in the report of the “Blue Ribbon” Electric Reliability Panel in 1997. A number of the organizational changes proposed by the panel have been instituted, including the creation of an independent Board of Trustees, a new standards development process, and a compliance enforcement program.

Initiatives to enhance the effectiveness of the organization include:

a. **Secure enactment of reliability legislation** — NERC, in cooperation with its Reliability Legislation Coalition, will strengthen and expand efforts to secure enactment of reliability legislation in the 108th Congress. In addition, NERC will take steps to prepare for the rulemaking that will follow enactment of legislation and the subsequent changes in the NERC governance documents. NERC will also seek to anticipate those things that may be needed for compliance with any such legislation and work with regional councils and others to be ready to move promptly to implement them when legislation is enacted.

b. **Promote efficient and effective regional administration of reliability** — NERC will work with regional organizations to ensure the efficient and effective administration of reliability. [See also Goal #1.b.]

c. **Pursue project funding from primary users and beneficiaries** — NERC has considered the development and implementation of a new system of funding that decouples NERC’s funding from the Regional Councils. NERC will seek funding of certain projects and activities directly from the primary users and beneficiaries of those projects.

d. **Implement organizational improvements and reforms** — NERC will implement this plan through its annual business plan. In addition, NERC’s technical committees are reviewing the committee organization to more effectively support NERC’s mission. The primary goal of this effort is to make the most effective and efficient use of industry technical expertise.
V. Implementation

This plan provides a framework for NERC’s development and annual activities. The goals identified herein are intended to provide direction and priorities while affording flexibility to deal with unanticipated challenges.

To remain well focused yet able to make appropriate adjustments as needed, NERC will:

a. **Conduct an annual review of the strategic plan** — Annually, the Board of Trustees will review the strategic plan to determine the changes needed. In conducting this review, the Board will be responsive to major challenges and trends within or affecting the bulk electric industry.

b. **Approve annual business plan** — The Board will approve the annual business plan developed by management and any changes to that plan made during the year. The business plan will identify the objectives that NERC will pursue in the coming year. The annual business plan will include the budget requirements for accomplishing these objectives.

c. **Monitor progress in achieving annual objectives** — Management will report to the Board on progress in implementing and achieving the objectives contained in the annual business plan.

VI. Conclusion

Successful implementation of this strategic plan and the associated annual business plans will enable NERC to achieve its mission and vision in an effective and efficient manner.

Because NERC will face new and changing demands, this plan and the objectives developed to support it are viewed as flexible documents to be reviewed and revised as necessary.

The enactment of federal reliability legislation in the United States will require parts of this strategic plan and associated business plans to be modified to reflect the form of the legislation passed and the new role and responsibilities that NERC would assume as the North American Electric Reliability Organization.
Recommendations on the Role of the Standing Committees

**Action**

Approve the recommendations in the Executive Committees’ report entitled “Review of the Future Role of NERC Committees.” The report makes seven recommendations for Board consideration regarding an organizational framework for the NERC committees going forward. There was broad consensus on five of the recommendations (1, 2, 3, 4, and 7), but there was a lack of unanimity on recommendations 5 and 6 regarding the appropriate number of committees. Therefore, the Executive Committees present for Board consideration both the majority and minority views on recommendations 5 and 6:

1. Adopt the ten NERC functions described in the report as a guiding reference for updating the scopes and functions of NERC committees and other NERC resources.

2. Direct the integration of the dispute resolution functions of NERC from the several programs in effect today to a single program that meets the needs of the standards development, compliance, and certification functions, and other NERC activities, while recognizing the unique characteristics of each.

3. Direct the integration of various aspects of compliance assessment, monitoring, and enforcement – and organization and personnel certification – into one coordinated program, distinct from but coordinated with the technical committee(s).

4. On an interim basis, retain the Critical Infrastructure Protection Advisory Group (CIPAG) as an advisory group reporting to the Board. Periodically review the CIPAG scope and organization, with a preference in the future toward integrating the critical infrastructure protection function into the technical committee(s).

5. **[Majority Recommendation]** Direct the integration of NERC’s volunteer industry experts into one technical committee reporting to the Board.
   
   **[Minority Recommendation]** Direct the reorganization of the volunteer industry experts into two technical committees in the areas of a) operating reliability, and b) planning and adequacy.

6. **[Majority Recommendation]** Adopt a technical committee representation model identical to that of the Stakeholders Committee.
   
   **[Minority Recommendation]** Assign each technical committee to propose for Board approval a representation model to meet its unique resource requirements.

7. Direct the technical committee(s) to submit for Board approval in June 2003, and initial implementation in July 2003, an updated scope document and plan for reorganizing to achieve assigned responsibilities.

Paul Barber, Chairman of the Market Interface Committee and the joint initiative, will present the report. Operating Committee Chairman Derek Cowbourne and Planning Committee Chairman David Whiteley will provide additional comments from the perspectives of their committees and will assist Chairman Barber in responding to questions.

**Background**

The Executive Committees have jointly completed an extensive review of how to adapt NERC’s committees to support the organization’s reliability mission going forward, in the face of challenges presented by a rapidly evolving electricity industry. The Executive Committees began this effort in March 2002 as a result of the Board directive in February adopting an open, weighted-segment voting model for the setting of bulk electric system reliability standards. One consequence of that decision is that NERC’s technical committees no longer manage the development of NERC standards or approve
The Executive Committees saw this significant change as an opportunity for a more thorough review of the role of the committees to achieve the following additional objectives:

- Refocus committee work priorities in support of NERC’s reliability mission.
- Retain the industry’s best reliability expertise on the NERC committees in the face of competing demands.
- Realize greater coordination of work assignments and integration of results among the committees, thereby creating efficiencies and minimizing redundancies.
- Ensure that committee representation continues to balance stakeholder interests in a changing industry, while simultaneously providing the requisite expertise and competencies.
- Establish a more dynamic committee process with a focus on adapting to evolving priorities and resource assignments, rather than fixed subcommittee structures.

In the report, the Executive Committees review a general NERC organizational framework that separates the standards, compliance, certification, and dispute resolution programs from the technical committees. Although the technical committees continue to advise those programs on reliability matters, each program has unique process and resource requirements and each is of such significance to NERC’s mission as to warrant reporting directly to the Board. In the suggested framework, the Stakeholders Committee continues to advise the Board on NERC policy matters.

Most of the report focuses on the role and makeup of the technical committees going forward. The Executive Committees conducted a thorough analysis of alternatives for organizing NERC’s committees. The majority prefers that industry volunteer experts be managed through a single technical committee encompassing operations, planning, market interface, and critical infrastructure protection. However, this majority view was countered by two persisting minority perspectives.

The first minority view is that the CIPAG should remain separate from the technical committee because of its unique responsibilities and interfaces, and the continuing importance of maintaining the high visibility of this initiative both within and outside of NERC. After extensive deliberation of this issue, and recognizing that the enduring model of one technical committee that includes infrastructure security may have to be delayed for a transition period, the Executive Committees agreed to recommend that the CIPAG remain as a separate advisory group reporting to the Board on an interim basis. The Executive Committees take this position with an understanding that:

- It is an interim approach imposed by necessity and should be subject to periodic Board review of the CIPAG scope and organization.
- Security guidelines or other requirements developed by the CIPAG that affect the bulk electric industry, whether intended to be voluntary or mandatory, should be reviewed by the appropriate technical committee(s) prior to Board approval.
- Close coordination between CIPAG and the technical committee(s) must become and remain a priority for all.

The second minority view is regarding a preference for two technical committees in the areas of operating and planning, in lieu of going to one technical committee. Because this issue was not resolved with unanimity, both alternatives are presented in this report, along with justifications for each. The report also describes measures that may be adopted to mitigate disadvantages that have been expressed for each option, so that whichever alternative the Board chooses can be assured successful implementation.

Public comments focused on the issue of one or two technical committees, committee size and representation, and the role the technical committee(s) in providing technical inputs to the standards process.
Review of Interdependency Between Gas Transportation and Electric Generation

Action
Approve scope of Gas/Electricity Interdependency Task Force

Background
In its October 2002 review and approval of NERC’s *Reliability Assessment 2002–2011* report, the NERC Board agreed with the Reliability Assessment Subcommittee’s general concern with the electric industry’s increasing dependence upon natural gas as a primary fuel for new electric generating units.

While no problems with the availability of natural gas supply for electric generation are anticipated over the next ten years, the gas pipeline infrastructure, including the manner in which gas pipelines are planned and operated, and its relationship to and potential impact on electric system reliability warrants further investigation.

Therefore, the Board directed the Planning Committee to develop a scope and project plan for studying the potential impacts of natural gas transmission system contingencies on electric system operations.

The PC approved the attached scope, developed by its Gas/Electricity Interdependency Task Force, for conducting the initial review phase of this assignment. The scope has also been endorsed by the executive committees of the Operating Committee and Market Interface Committee. The current task force roster is also attached.

Ken Wiley, President and CEO of the Florida Reliability Coordinating Council, who chairs the task force, will present the scope for approval.
NERC  
GAS/ELECTRICITY INTERDEPENDENCY TASK FORCE  

REVIEW OF INTERDEPENDENCY BETWEEN  
GAS TRANSPORTATION AND ELECTRIC GENERATION  

SCOPE  

PURPOSE  

The purpose of the review is to determine the interdependency relationship between gas pipeline operation and planning, and electric generation operation and planning reliability over the next 10 years. If, in fact, negative reliability impacts are found, it is anticipated that additional industry effort will be established to perform any detailed analysis or studies to determine precise mitigation measures. The review will identify and recommend possible measures to mitigate any negative reliability impacts.

It is not the purpose of this task force to make an assessment of the adequacy of gas supplies to meet the needs of gas-fired electrical generation. This is an important topic but it is outside the scope of this task force review.

TASK FORCE COMPOSITION  

| FERC | DOE | EPRI | NARUC | National Energy Board of Canada | Provincial Regulatory Agencies | Canadian Electricity Association | Canadian Gas Association | Gas Pipeline Associations | Individual Pipeline Owners | Electric System Planners and Operators | Gas Supply Organizations | Gas Local Distribution Companies | Generator Organizations | Individual Generator Owners | Large Customers | Regions, or subregions which have a high dependency on natural gas | ISOs/RTOs | National Petroleum Council |

TASK FORCE REPORTING RELATIONSHIP  

The task force shall report to the NERC Planning Committee. Status reports shall be given to the Planning Committee, Operating Committee, Market Interface Committee, and the Board of Trustees.
TASK FORCE ACTIVITIES

PHASE I:

(1) Establish a work plan to develop a thorough understanding of the following:
   (a) Gas pipeline operating practices
   (b) Gas pipeline planning process, including criteria and standards
   (c) Gas pipeline tariffs
   (d) Regulatory approval process for FERC, NEB, individual states and provinces pertaining to gas pipelines
   (e) Relationship or comparison to practices in the electric industry
   (f) Electric and gas interconnectivity
   (g) Relationship between gas pipeline operation and planning, and electric generation operation and planning reliability over the next 10 years.

(2) Gather information on specific problems that have occurred on the gas pipeline systems, including any consequences to the electrical systems.
   (a) All events within the last 36 months
   (b) Major events older than 36 months but less than 8 years old
   (c) Major pipeline events that affected deliverability but did not affect electric generation (near-miss events) within the last 36 months

(3) Gather information and reports from existing studies that have examined the interaction of gas pipeline operation and planning, and electric generation operation and planning.

(4) Prepare a Summary Report on gas pipelines and their interrelationship with, and potential impact on, the reliability of electric generation operation and planning.

(5) Based on Phase I results, prepare recommendations on what future work (if any) should be done by NERC to ensure that gas transportation issues, such as those listed below, do not adversely affect the reliability of the North American electric systems.

   a. Existing routes
   b. Pipeline capacity
   c. Current utilization
   d. Projected needs
   e. Planned expansions with assessment of probability of completion and key dates
   f. Issues identified in Phase I
SCHEDULE

Phase I is anticipated to be completed within 9 months.

Approved by the NERC Planning Committee: January 28, 2003
Approved by the NERC Board of Trustees: February ____, 2003
NERC GAS/ELECTRICITY INTERDEPENDENCY TASK FORCE

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Request for Regional Verification Mechanisms for Operating Security Limit Violations

Action
Request each Regional Council to develop a verification mechanism for reporting Operating Security Limit violations.

Background
At its October 2002 meeting, David Hilt, NERC Director-Compliance, briefed the Board on the status of the Compliance Enforcement Program and results to date. The Board expressed interest in hearing more specific reports on significant instances of noncompliance with NERC and regional standards, especially violations of Operating Security Limits (OSLs). The Board directed that compliance reports be given at each Board meeting and, in the event of significant events, as they happen between Board meetings.

Lack of Complete and Consistent Reporting
Violating OSLs poses serious risks to the reliability of the bulk electric system. Violations can result in system instability, cascading outages, voltage collapse, etc. Reliability Coordinators and other system operators must recognize when the system is operating beyond OSLs and return the system to a safe operating state as quickly as possible.

Although Operating Policy 2.A.2.1 requires system operators to report OSL violations within 72 hours of occurrence, NERC has received very few reports from most Regions. Also, during several Transmission Loading Relief (TLR) investigations, the NERC Operating Reliability Subcommittee determined that certain OSL violations were never reported.

One of the main reasons for inconsistent and/or incomplete reporting of OSL violations is the lack of a clear definition in NERC Policy of what constitutes an OSL violation and what actions Reliability Coordinators and other system operators are expected to take to return the system to a safe operating state. Several Regions have established their own definitions and required responses.

To develop a uniform NERC definition that is clear and concise and to review and assess the reliability impacts of reported OSL violations, the Operating Committee has formed the Operating Limit Definition Task Force. This task force is to report to the Operating Committee at their March 2003 meeting with recommendations. The task force will also provide its results to the Standards Drafting Team developing the Reliability Standard “Operate Within Limits.”

Accurate reporting of OSL violations also requires effective reporting mechanisms. Reporting of OSL violations relies on operating entities to self-report the event within 72 hours. However, a verification mechanism is necessary to ensure that all violations are reported.
Status of OSL Definitions and Violations Reporting

Reporting of OSL violations in the first three years of the Compliance Enforcement Program varies among the regions, and can be categorized as follows:

Category 1
The Region has developed a clear definition of OSL violations, an effective OSL reporting mechanism, and reporting has improved. NERC is receiving accurate compliance information but may not be receiving required 72-hour notification of violations.

Category 2
The Region uses the NERC definition of OSL violations. NERC may not be receiving accurate OSL violation reports or the required 72-hour notification of OSL violations. (The primary reason for this is the lack of a uniform and clear NERC definition of OSL.)

Category 3
The Region uses the NERC definition of OSL violations. Incidents have been identified where the system was operating in an unknown or unanalyzed state. NERC may not be receiving accurate OSL violation reports or required 72-hour notification of OSL violations. (This is the most severe case and the cause for most concern.)

Actions Recommended
The Director of Compliance recommends that the Board request each Regional Council develop a verification mechanism for reporting OSL violations within their respective Regional Compliance Enforcement Programs and to NERC in accordance with NERC Operating Policy 2.A.2.1. This mechanism should require Reliability Coordinators and other entities responsible for reporting OSL violations to self-certify the number of OSL violations reported each quarter for their area of responsibility, include a certification that the OSL violations were reported to NERC within the required 72-hour period, and be signed by an individual with appropriate authority. Certifications should be provided at least quarterly to allow for timely reporting to the NERC Board.

The reporting mechanisms should be in place once a uniform definition of an OSL violation is approved.

WECC has instituted a verification mechanism that could serve as a model for other Regions.
Reliability Coordinator Audit Program

Action
None

Background
The Board, in October 2001, instructed the Director of Compliance to evaluate in future audits how Reliability Coordinators are assuring that their operations are independent of those who participate in the marketplace, to investigate specific complaints, and to report results and recommendations to the Board.

Reviews of all of the NERC Reliability Coordinators were completed in November 2002 and the final audit reports are posted on the NERC web site under “Compliance.”

Findings
The audits found that all Reliability Coordinators are acting to preserve the reliability of the grid in conformance with the Reliability Coordinator Standards of Conduct.

The audits also found that not all Reliability Coordinators perform the same functions at the reliability coordinator location. For example, some Reliability Coordinators delegate many of their responsibilities to control areas within their reliability area. While Operating Policy 9 allows some delegation, there is concern with the number of functions delegated by some Reliability Coordinators.

NERC Actions Taken
The primary reason Reliability Coordinators discharge their responsibilities differently is because each has its own interpretation of Operating Policy 9 and Appendix 9D. To address this, the Operating Committee formed a task force to consider the following questions:

- Reliability Coordinators are expected to monitor the ‘big picture.’ How are these expectations defined in terms of tools, system monitored, etc.?
- What functions are appropriate for delegation and how many functions should reliability coordinators be allowed to delegate?
- What is required in the Regional and RTO reliability plans for NERC to approve them?
- Should the expectations and requirements of a Reliability Coordinator be coordinated with those included in the Functional Model definition of a “Reliability Authority?” If yes, how should they be coordinated?

The task force is expected to report its initial recommendations to the Operating Committee at its March 2003 meeting where it will determine appropriate actions to revise NERC Policy 9 and Appendix 9D along with the certification requirements for a Reliability Authority. Also, the Operating Committee will determine what should be included in reliability plans submitted to it for approval based on these recommendations. The NERC Director – Compliance will then modify the audit procedures to account for these changes.
Request for Reports on Regional Compliance and Enforcement Programs

Action
Request a report by May 1, 2003, from the Chairman or Regional Manager of each Regional Reliability Council, on the Region’s implementation of a contract-based compliance and enforcement program, for discussion at the June 2003 Board of Trustees meeting.

Background
In February 2001, NERC initiated a program for contract-based Regional compliance and enforcement programs. These programs, once fully implemented, will add the ability to assess financial penalties and other sanctions for violations of selected reliability rules. The programs are modeled after the Reliability Management System that WECC initiated four years ago. The key feature of the NERC program is that members of Regional Councils agree in advance to subject themselves to specified compliance actions if they are found in violation of specified reliability rules. Under the Agreement for Regional Compliance and Enforcement Programs, the Regions will monitor and enforce certain NERC reliability standards, including the imposition of financial penalties and other sanctions. NERC will oversee, coordinate, and assess the Regional compliance programs. Each signatory to the Agreement has a representative on a Compliance Agreement Participants Group, which administers the program.

Six Regional Councils and NERC signed the Agreement for Regional Compliance and Enforcement Programs in February 2001. Nine of the ten Regional Councils have now signed the Agreement. The Agreement contemplates that each Region will implement the program through agreements with its members. As indicated in the attached status report, several Regions have not yet implemented the Agreement. It would be useful to hear from each Region what it has accomplished so far, what are its plans for implementing or continuing the program, what obstacles it has encountered in implementing the program and, for those Regions that have implemented the program, what impact the program is having on compliance.

Having a report from each Regional Council by May 1, 2003, would enable the Trustees to review the reports in advance of the June Board meeting and prepare for a discussion of the program with participation by the Regional Chairmen or Managers.
Nine of the ten Regional Reliability Councils have signed the Agreement for Regional Compliance and Enforcement Programs (the “Agreement”) that the Board approved in February 2001: ECAR, ERCOT, FRCC, MAIN, MAPP, NPCC, SERC, SPP and WECC.

The current status of each Region’s implementation of the Agreement follows. It should be noted that all ten Regions are participating in the NERC compliance program. The additional feature that the Agreement brings to the compliance effort is the possibility of contract-based sanctions for non-compliance.

**ECAR:** The ECAR Board has approved antitrust compliance guidelines. Thirteen of the 19 Members of ECAR have signed the ECAR RCEP Agreement. Four have said they will not participate. Two are still considering the matter.

**ERCOT:** ERCOT is still discussing the matter. ERCOT supports this program. ERCOT is a single point of control Interconnection and there are no Control Areas under ERCOT to which compliance can be administered. ERCOT is discussing how any penalties would be assessed under its current business and operating protocols.

**FRCC:** The FRCC program is on hold. FRCC continues to monitor the NERC strategic planning initiative and pending legislation.

**MAIN:** MAIN, after signing the NERC Agreement, is presently sending its Plan B agreement to its members for signature. MAIN is continuing with implementation of the MAIN Plan B Program in concert with the NERC Plan B Program.

**MAPP:** 14 (up from 11) out of a necessary 21 of its members have signed the MAPP compliance agreement. Under the MAPP program two-thirds of its members must sign before the program becomes effective. The MAPP Chair has sent a letter soliciting greater participation. MAPP intends to field test the enforcement matrix during 2003.

**NPCC:** In 2002 NPCC reported 100% compliance with the requirements contained in the Agreement for Regional Compliance and Enforcement Programs (e.g. CPS1, CPS2 and DCS).

All members of NPCC participate in its Reliability Compliance and Enforcement Program (RCEP) as part of their obligations under the Membership Agreement. The RCEP Enforcement Panel (EP) has completed its review of one of the two instances of non-compliance with NPCC Criteria that were identified as part of the 2002 program and will issue a sanction letter to the violator. The EP is currently reviewing the second violation. NPCC is considering expanding its RCEP to include control area certification and a compliance template for anti-cascading security limits.
NPCC has also completed a study of compliance sanction alternatives. The analysis concluded that NPCC’s existing sanction program, which is based on escalating sanction letters to Boards of Directors and regulators, has demonstrated the effectiveness of such notifications. NPCC will continue to explore market-based compliance mechanisms, as markets evolve.

**SERC:** In October 2002, the SERC Board voted to modify the SERC Agreement “…to take such actions as are necessary to put in place the RCEP…”. SERC will not implement the RCEP until signed Agreements representing at least 90% of the weighted member votes have been received. Agreements are in the hands of SERC members for execution.

**SPP:** All 18 control areas are participating in the program. SPP is in the process of adopting the new enforcement matrix for 2003. The present schedule for implementing financial sanctions is January 1, 2004.

**WECC:** WECC’s program began before the NERC initiative, and its program (which includes the three NERC standards and eight other standards) is up and running, with a few years’ experience now. WECC reports that its program (Phases 1 and 2) has been very effective in minimizing violations. Implementation of four more standards in Phase 3 is planned during the first part of 2003. WECC uses a combination of letters and monetary penalties for enforcement of compliance.

MAAC has not signed the Agreement. After discussions with MAAC representatives, it appeared that MAAC was insisting on modifications to the Agreement that the other signatories were not willing to make. The other signatories believed that all Regions should sign the same agreement. The other signatories were willing to entertain some changes to the Agreement, but did not believe it was appropriate to undertake a substantial renegotiation of the Agreement at this time. The Compliance Agreement Participants Group did vote to include MAAC in all its meetings and conference calls, and MAAC has been a full participant in the discussions.

MAAC reports that, following the October 2002 NERC Board meeting, the MAAC Members Committee revisited the Agreement. MAAC reports that MAAC members continue to support NERC reliability standards, are obligated to abide by them, and have a compliance program in place. However, MAAC members continue to hold the opinion that a revised agreement, a draft of which was sent to NERC on January 13, better addresses their concerns than does the standard NERC Agreement. MAAC reports that member concerns revolve around regional differences and flexibility, the temporary nature of the Agreement, state authority, and making use of market solutions. The Compliance Agreement Participants Group will discuss the proposal from MAAC at its next meeting.
Action
None

Background
The Compliance Enforcement Program (CEP) is designed to monitor compliance with all NERC reliability standards and promote compliance through rewards, penalties and sanctions to protect the reliability of the North American bulk electric system. As such, the CEP places significant emphasis on encouraging good reliability performance by conducting on-site audits of control areas, Reliability Coordinators, and others in an effort to help resolve compliance issues before they become reliability problems.

In most cases, the Regional Councils monitor compliance with the standards, with NERC staff oversight and coordination. In those cases where standards call for compliance by the Region itself, NERC staff monitors compliance.

2003 Program
We do not see a need to introduce any additional Policies or Standards into the program for 2003. Those Policies and Standards selected for monitoring in the 2003 program (see attached) are those that are most likely to endure, in some form, as new reliability standards.
NERC 2003 Compliance Enforcement Program

Operating Measures

1. Control Performance Standard CPS-1 and CPS-2
2. Disturbance Control Standard
3. Develop and maintain formal policies and procedures to address the execution and coordination of activities that affect transmission system security
4. Operating Security Limit Violation (30 minute return)
5. Interchange Schedules only be implemented between adjacent Control Areas
6. Tags input into the IDC or provided to Reliability Coordinator
7. Adequate facilities are provided for the system operators to monitor specific system parameters
8. Control Area or Operating Authority provides system data to Reliability Coordinator
9. Reliability Coordinator to exchange system data within time interval specified
10. Operators must implement and communicate emergency plans
11. Emergency Operation Plans developed and maintained
12. System Restoration Plans developed and updated
13. System Operator authority and responsibility to implement real-time actions to ensure reliability
14. Operator Certification
15. Reliability Coordinator to perform next day study
16. Reliability Coordinator to take actions requested by other Reliability Coordinator
17. Issuance of Energy Emergency Alerts

Planning Measures

1. Conduct a system performance assessment under normal conditions
2. Conduct a system performance assessment under single contingency
3. Conduct a system performance assessment under multiple contingencies
4. Conduct a self-assessment of regional & interregional reliability
5. Provide Regional data needed to assess reliability
6. Conduct system performance assessments to coordinate plans for new facilities
7. Develop requirements for the installation of disturbance monitoring equipment
8. Develop data requirements and reporting procedures for steady state modeling
9. Develop data requirements and reporting procedures for dynamics modeling
10. Develop and maintain a library of steady state models
11. Develop and maintain a library of dynamics models
12. Develop a Regional procedure to monitor/review/analyze/correct transmission protection misoperations
13. Document and implement a transmission protection system maintenance and testing program
14. Document protection system misoperations, analyses, and corrective actions
15. Demonstrate consistency of entities’ Underfrequency Load Shedding (UFLS) program with the Regional UFLS program
16. Document and implement an UFLS maintenance/testing program
17. Analyze and document UFLS program performance
18. Document and implement a Regional Special Protection System (SPS) review procedure
19. Maintain a Regional SPS database
20. Document data and study results for new/proposed SPS installations
21. Document and analyze SPS misoperations and corrective action plans
22. Document and implement an SPS maintenance/testing program
23. Establish and maintain a Regional blackstart capability plan
24. Demonstrate by simulation/testing that a blackstart unit can perform its intended function
Critical Infrastructure Protection Advisory Group
Scope and Organization Transition Plan

Action
Approve the scope and organization transition plan for the Critical Infrastructure Protection Advisory Group (CIPAG.)

Background
The CIPAG has developed for Board approval the attached revised scope to ensure participation in its work by all industry segments and to ensure expertise in the areas of physical security, cyber security, operations, and policy.

To fulfill the new scope, the CIPAG has also developed for Board approval the attached organization transition plan to guide the transition of CIPAG from its current 16 voting member roster to a 36 voting member roster by May 2003.

NERC, which has been designated the Electricity Sector Coordinator by the U.S. Department of Energy, has taken a number of significant actions to improve the protection and preparedness of our electricity industry’s critical infrastructure. CIPAG has been instrumental in many of these actions. With the rapid development of new and enhanced security methodologies and the establishment of the U.S. Department of Homeland Security, CIPAG’s role and responsibilities will continue to grow. The new scope and expanded membership will help the CIPAG and NERC to meet these growing responsibilities.

Kevin Perry, SPP Manager of Information Technology and Chairman of the CIPAG, will present the CIPAG scope and organization transition plan for Board approval.
Critical Infrastructure Protection Advisory Group

Scope

Mission
The mission of the Critical Infrastructure Protection Advisory Group (CIPAG) is to advance the physical and cyber security of the critical electricity infrastructure of North America.

Activities
1. Serve as an expert advisory panel to the NERC Board of Trustees and Standing Committees in the areas of physical and cyber security.

2. Serve as an expert advisory panel to the Electricity Sector Information Sharing and Analysis Center (ES-ISAC) including the ES-ISAC’s role in implementing the Indications, Analysis, and Warnings Program.

3. Coordinate and communicate with those responsible for both physical and cyber security in all electric industry segments, including (among others) the American Public Power Association, Canadian Electricity Association, Edison Electric Institute, Electric Power Research Institute, Electric Power Supply Association, National Rural Electric Cooperative Association, North American Energy Standards Board, the Nuclear Energy Institute, and the NERC Regions.

4. Coordinate and communicate with the other critical infrastructure sectors as appropriate.

5. Liaison with federal government agencies charged with critical infrastructure protection.

6. Establish and maintain an information reporting procedure for critical infrastructure protection among industry segments and, as appropriate, with federal government agencies.

7. Conduct forums and workshops related to the scope of CIPAG.

The essential work of the CIPAG regarding the Electricity Sector include the following actions:

✓ Protection — includes physical security, cyber security, emergency preparedness and response, business continuity planning, and recovery from a catastrophic event, with emphasis on deterring, preventing, limiting, and recovering from terrorist attacks.

✓ Deterring — to dissuade one from even trying.

✓ Preventing — to cause an attempt to fail.

✓ Limiting — to constrain consequences in time and scope to something less than what they would have been otherwise. And,

✓ Recovering — returning to normalcy quickly and without unacceptable consequences in the interim.

Reporting
The CIPAG reports to the NERC Board of Trustees.

Approved by CIPAG: January 17, 2003
Approved by Board of Trustees:

Phone 609-452-8060 ■ Fax 609-452-9550 ■ URL www.nerc.com
Voting Members

- 2 selected by the American Public Power Association
- 2 selected by the Canadian Electricity Association
- 2 selected by the National Rural Electric Cooperative Association
- 30 Each of the ten NERC Regions will appoint three members, one each with expertise in Physical Security, Cyber Security, and Operations as defined below.
- If other entities not represented in this model request representation, the request will be considered at the next CIPAG meeting and subject to NERC Board approval.

There will be a total of 36 voting members.

- The chair and two vice chairs will be appointed by the NERC Board from among the voting members.
- Regional representation will be appointed by each of the ten Regional Councils.
- Members will be selected based upon expertise in these disciplines:
  ✓ **Physical Security** of Electricity Sector facilities (including, not limited to, generation, dams, transmission, critical distribution facilities, buildings).
  ✓ **Cyber Security** primarily focused on Market and Power Operations Systems (including, but not limited to, SCADA, EMS, DCS, and also systems like OASIS), but with consideration also to systems required for business continuity.
  ✓ **Operations** with focus on system operations at the control area (balancing authority) and reliability coordinator levels.
- Appropriate representation will be provided to deal effectively with **Policy Matters** related to electricity industry evolution and government policy.

Nonvoting Members

- Governmental agencies at the national, provincial, and state levels
- Other electricity industry associations
- Electric Power Research Institute
- Vendors
- Other critical infrastructure protection sectors
- Other observers as appropriate
- CIPAG secretary
- NERC committee meetings are open, with the understanding that certain discussions may, as ordered by the chair, be held in closed session limited to the voting members and secretary.
- Nonvoting members have voice at meetings

Structure

The CIPAG shall have an Executive Committee with the following membership:

- Chair
- Vice Chairs
- One CIPAG member (appointed by the chair with consent of the members) representing each:
  ✓ **Physical Security**
  ✓ **Cyber Security**
  ✓ **Operations**
  ✓ **Policy Matters**
- Secretary

Executive Committee duties:
1. Respond to urgent matters by calling conference calls or special meetings
2. Prepare meeting agendas
3. Coordinate CIPAG activities with NERC standing committees and other entities
4. Report to the NERC Board of Trustees

Critical Infrastructure Protection Advisory Group Scope
Page 2
The CIPAG may address security-related issues as it deems fit or may assign such issues to self-directed work teams.

Self-directed work teams will take assignments from the CIPAG and all work products will be presented to the CIPAG for any further action.

The CIPAG will transition from its existing structure to that detailed in this scope, for a one-year period, following review for approval of the NERC Board at its February 2003 meeting. This structure will be reviewed by the CIPAG and NERC committee(s) with a detailed report prepared by the CIPAG presented to the NERC Board by February 2004.

Terms of chair, vice chair(s), and members will be determined during the transition.

**Governance**

1. Roberts Rules of Order will apply.
2. A CIPAG quorum requires 50% of the voting roster members to be present or represented by proxy. Any or all members of the CIPAG may participate in a meeting, including being counted as part of the quorum, by means of a communication system by which all persons participating in the meeting are able to hear each other.
3. Motions carry upon affirmative vote of two-thirds of the total yes and no votes cast during the presence of a quorum. Abstentions do not count as votes.
4. Only roster alternates may be designated as proxy representatives who may attend and vote at meetings provided the absent member notifies in writing (letter, facsimile, or e-mail) the chair, vice chair, or secretary. The proxy representative and his or her affiliation shall also be named in the correspondence. Any person, member or proxy, will have one vote; no regular voting member of CIPAG may hold a proxy for another member.
5. The agenda of actions to be voted upon shall include the general wording of proposed motions, and a brief discussion of the reasons for the motion. Motions can be made during a meeting or conference call. Only a voting member can provide a motion. A reasonable effort shall be made by those sponsoring items on a meeting agenda to have the action to be voted on and with background material distributed with the agenda or in a timely manner before the meeting.
6. CIPAG may take action without a meeting if, after notice to all members, two-thirds of the members consent to the action in writing. Such action without a meeting shall be performed by electronic (facsimile or e-mail) ballot. The Executive Committee may initiate the call for such an action. Any member may ask the chair to arrange for such an action.
7. On occasion, the CIPAG may be called upon to provide information or support in relation to a matter that requires secrecy. Upon such an occasion and with the approval of the chair of the Board of Trustees, the chair of the CIPAG may convene a working group to provide such information or support without notice or approval of any other member or group. The existence of such a working group, its mission and results, will be shared with the members only to the degree and at the time deemed appropriate by the chair of the Board of Trustees.
8. The CIPAG will coordinate its activities with the other NERC committees and working groups to assure the highest degree of collaboration possible.
9. CIPAG actions, documents, and recommendations will be distributed to the NERC committees and working groups and posted for Industry comment (assuming sensitivity so permits, at the discretion of the CIPAG). NERC committee, working group, and industry comments will be considered by the CIPAG prior to forwarding actions or documents to the Board for approval.
10. CIPAG meetings will be conducted at the discretion of the chair, generally on a quarterly basis.
Critical Infrastructure Protection Advisory Group
Organization Transition Plan

This Transition Plan provides for transitioning from the existing Critical Infrastructure Protection Advisory Group (CIPAG) voting membership to that proposed in the “Scope: Critical Infrastructure Protection Advisory Group,” January 17, 2003 (Scope) and will be implemented given approval of the Scope and Transition Plan by the NERC Board of Trustees (Board) at their February 2003 meeting.

1. There are differences among the structures and the mechanics of the current standing committees and also with the proposed CIPAG. The Board will review the Scope and mechanics presented in this Transition Plan in 2004 for effectiveness.

2. The key part of transition is the change from the current voting roster (attached; voting members indicated) to the one proposed in the Scope.

3. The Scope proposes CIPAG membership from sponsoring organizations:

   A. From each of the ten NERC Regions: three voting members with named alternates (as desired by the organizations providing names). The following disciplines will each be represented, with consideration to policy matter expertise:
      a. Physical Security
      b. Cyber Security
      c. Operations

   B. From American Public Power Association: two voting members with named alternates (as desired by the Association). Members will be selected to represent one or more of the following disciplines:
      a. Physical Security
      b. Cyber Security
      c. Operations
      d. Policy Matters

   C. From Canadian Electricity Association: two voting members with named alternates (as desired by the Association). Members will be selected to represent one or more of the following disciplines:
      a. Physical Security
      b. Cyber Security
      c. Operations
      d. Policy Matters

   D. From National Rural Electric Cooperative Association: two voting members with named alternates (as desired by the Association). Members will be selected to represent one or more of the following disciplines:
      a. Physical Security
      b. Cyber Security
      c. Operations
      d. Policy Matters

Approved by CIPAG: January 17, 2003
Approved by Board of Trustees:
4. Members and alternates serve at the pleasure of the presenting organizations with an expectation of a minimum of two years. It is recommended that membership be reviewed by sponsoring organizations biannually.

5. NERC staff will send a letter to the sponsoring organizations requesting members and alternates as above. Basic qualifications for each discipline will be included. This letter will be sent shortly after Board approval of the Scope. The proposed member and alternate roster will be sent to the Board for approval. It is expected that the new roster can be in place for a proposed April 2003 CIPAG meeting.

6. It is expected that those interested in being appointed as a member or alternate will communicate with their Regional Manager or Association.

7. The officers will consist initially (during the transition period from initial organization to the end of 2003) as those currently in position. This will help to assure continuity during the expected continued rapidly changing security environment in Canada and the United States.

   A. Chair: Kevin Perry, SPP
   B. Vice Chair: Larry Bugh, ECAR
   C. Vice Chair: Michael Lynch, DTE Energy

8. Prior to 2004, the CIPAG chair will appoint a Nominating Task Force, for CIPAG approval, to recommend officers, as defined in the Scope, for 2004. This will be approved by the CIPAG and the Board.

9. The Nominating Task Force will also present to the CIPAG the remaining members of the CIPAG Executive Committee.
Critical Infrastructure Protection Advisory Group Report

Action
None

FERC Security Standards
The CIPAG worked closely with the Federal Energy Regulatory Commission (FERC) in developing the security standards included in the Standard Market Design NOPR. CIPAG also prepared comments on the NOPR, which were approved by the Board and filed in November 2002.

NERC’s comments on security standards were discussed at a FERC workshop on December 6, 2002 and substantially accepted as an appropriate start for securing the electronic data required for wholesale electricity markets.

On February 4, 2003, FERC is holding a meeting to discuss implementation of the security standards and how compliance with these standards will be monitored. NERC CIP and compliance staff will participate. The Board will be briefed on the results of this meeting.

CIP Workshops
The CIPAG will present a series of workshops to raise awareness within the electricity industry to the physical and cyber security challenges our industry faces. The Security Guidelines approved by the Board in June 2002 will be presented at the workshops along with typical action steps, security tools, and communications. Eight workshops are planned during the first half of 2003 throughout Canada and the United States.

The workshop agenda, including dates and locations for most of the workshops, is attached.

Public Key Infrastructure (PKI) Project
The CIPAG is continuing development of the “Energy Market Access and Reliability Certificates” plan, and a PKI architecture is nearing completion. This project will provide electronic security of existing and future computer-based systems used to exchange data within the electricity sector, including electronic tagging, OASIS, electronic scheduling and the Reliability Coordinators Information System.

Next steps in the project will be authorization of Certificate Authorities and development of one or more Registration Authorities. This effort is being carried out in conjunction with the American Gas Association, American Petroleum Institute, and the North American Energy Standards Board, and with support from the Department of Energy.

By September 2003, the PKI system is expected to be operational, with Certificate Authorities in place, eMARC certificates in actual use, and interoperability testing complete.

Security Guideline for Electronic Control and Protection Systems
Control systems (including SCADA, EMS, station controls, line relays) have been the source of much debate as to their vulnerability to intrusion and attack. A so-called swarming attack, including both physical and cyber effects, has been postulated as likely. A self-directed work
team of the CIPAG has drafted a security guideline – the first in a likely series – to deal with this concern. The guideline will be presented to the NERC standing committees for input. CIPAG expects that this guideline can be brought to the Board for approval at its June 2003 meeting.

**Spare Equipment Initiative**
NERC recognizes the potential vulnerability of and long lead time to replace certain critical electrical equipment following an attack. A self-directed work team of the CIPAG has developed a spare equipment database to identify the existence of spare equipment that could be used to facilitate restoration of the system following an attack. The database is nearly ready for use by the industry. CIPAG envisions expansion of the database into a second phase, which will include gaps analyses to guide in the establishment of additional spare equipment.
Meeting The Security Challenge Workshop  
February 26–27, 2003  
Dallas, Texas

Introduction
Protecting the electric power grid from disruption is essential — no one disputes the point. Given today’s threat environment, the question is how? Physical and cyber assets are at risk. Threats lurk inside the organization as well as out. Vulnerabilities exist.

NERC is sponsoring workshops across the country to help address the question of how to protect our critical infrastructure. The *Security Guidelines for the Electricity Sector*, developed by NERC’s Critical Infrastructure Protection Advisory Group last year, will be the cornerstone of discussion.

Subject matter experts from the industry and federal government will present the guidelines, discuss FERC’s proposed standards for cyber-security, and describe tools and assessment techniques available today to help companies determine vulnerabilities and define effective protection strategies. The relationship between the electricity sector and the new Department of Homeland Security will be explored.

The first workshop will be in Dallas, Texas on February 26–27. More are in the planning stages and a full schedule will be announced soon. If you have responsibility in the physical or cyber-security areas, plan on attending a workshop. The dates and locations have been selected to allow you to choose the most convenient schedule.

Agenda

**Day 1**
8 a.m. – noon

Welcome

Critical Infrastructure Protection: Roles and Relationships
- Department of Homeland Security
- Department of Energy
- ES-ISAC
- NERC

Threat Awareness:
- NERC’s Indications, Analysis, Warnings Program
- Threat Alert Levels for the Electricity Sector

Security Guidelines: An Overview
Luncheon: Speaker TBA

**Day 1**
1 p.m. – 5 p.m.

Security Guidelines: Breakout Sessions
Security Guidelines and FERC’s Proposed Cyber Security Standards
Homework Assignment!

**Day 2**
8 a.m. – noon

Review Homework Assignment
Assessment Methodologies
- Red-Grey-Blue Self-Assessment Methodology
- DOE Vulnerability Assessment Methodology
- Risk Assessment Methodologies (for Dams, Transmission, and Fossil)
Meeting The Security Challenge Workshop

The Presenters

- NERC CIPAG
- ES-ISAC
- U.S. Department of Energy (DOE)
- National Infrastructure Protection Center (NIPC)
- Federal Bureau of Investigation (FBI)

The Schedule

Several one-and-a-half day workshops have already been scheduled and others are in the final planning stages:

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<thead>
<tr>
<th>Date (2003)*</th>
<th>Location</th>
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<tr>
<td>Confirmed:</td>
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<tr>
<td>February 26–27</td>
<td>Dallas, TX</td>
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<tr>
<td>March 13–14</td>
<td>Phoenix, AZ</td>
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<tr>
<td>March 27–28</td>
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*Other dates and locations may be added as needed.

Hotel Information for the February 26–27, 2003 Workshop

Sheraton Grand Hotel (at airport), 4440 West John Carpenter Freeway, Irving, Texas 75063
Phone: 972-929-8400

A block of rooms is being held for a rate of $104 single/double. The cut-off date for sleeping rooms is February 11, 2003. Check in time is 3 p.m. and check out is noon. The hotel is located 2.5 miles from Dallas/Fort Worth International Airport. Complimentary airport shuttle service is available 24-hours a day. Taxis cost about $14. When making your hotel reservations, please make sure to mention North American Electric Reliability Council/NERC so your reservation is credited to our room block.
Registration for February Workshop Only

On-line registration also available at NERC’s web site — www.nerc.net

Meeting the Security Challenge Workshop
February 26–27, 2003

Sheraton Grand Hotel (at airport)
4440 West John Carpenter Freeway
Irving, Texas 75063
Phone: 972-929-8400

The workshop registration fee is $125 per person. This price includes meeting facilities, materials, and refreshments. Please pre-register — registration at the door is $175. NERC will accept cancellations and substitutions one week prior to the session.

Name:
Title:
Organization:
Address:
City/State/Zip:
Telephone:
E-mail Address:

Method of Payment:
☐ Check — Make checks payable to NERC
☐ Visa ☐ MasterCard (Please note we do not accept American Express or Discover)

Card Number:
Name of cardholder:
Expiration date:

Please return this form to Karol Lane by February 17, 2003 to:
Fax: (609) 452-9550 or E-mail: karol.lane@nerc.net

Space is limited — Please pre-register!
Attire is business casual.
Action
None

Summary
The Board, on November 4, 2002, ratified the October 22, 2002 decision of the NERC Operating Committee to approve the revised reliability plans submitted by the Midwest Independent System Operator (MISO) and the PJM Interconnection, including the conditions imposed on that approval. We expect some revisions to these areas in the near future (for example, Illinois Power is moving from PJM to MISO), and will keep the Board informed.

The next phase of the PJM and MISO evaluation involves the expansion of their market areas. This begins in May 2003 with PJM’s inclusion of American Electric Power and Dayton Power & Light into the PJM market.

Background
Reliability Coordinator Expansion Approved — Following the Board’s October 8, 2002 meeting, the Operating Committee held a special meeting to consider the expanded reliability coordination areas of MISO and PJM. The OC approved the expanded MISO-PJM reliability coordination “footprint” with the following stipulations:

1. This approval is only to allow MISO and PJM to expand their respective Reliability Coordinator footprints to include their new members, and
2. This approval does not include the expansion of PJM’s locational marginal pricing (LMP) market footprint or the commencement of MISO’s LMP market, and
3. MISO and PJM will revise and resubmit their Reliability Plans to NERC and the Regional Councils for approval prior to changing their congestion management processes or expanding their LMP markets, and
4. MISO will update its Reliability Plan to match PJM’s Plan with respect to PJM’s Attachment A “Emergency, Voltage Stability, Voltage Collapse, and Restoration Protocols,” and
5. MISO will replace the word “transactions” with the phrase “energy flows” in Section J.1. of its Reliability Plan.

Furthermore, the Operating Committee agreed that:

“This approval is only the first stage of the approval contemplated in the FERC Order issued July 31, 2002 under Docket EL02-65-000, Paragraph 48.”

**Next Phase: Market Expansion** — From NERC’s perspective, reliability issues resulting from market expansion are more complicated than those from the reliability coordination expansion. Market expansion requires the coordination of the LMP market dispatch across the PJM (and eventually, MISO) market area with other congestion mitigation methods — including the TLR Procedure — used by surrounding transmission systems that remain under other tariffs (e.g., the *pro forma* tariff). The LMP dispatch will naturally create flows on parallel transmission systems, and vice versa. The key issue is how these flows are dealt with when they cause congestion on parallel systems.

NERC will also consider how the increase in PJM’s control area size will affect the accuracy of the Interchange Distribution Calculator (IDC), which models the control areas in the Eastern Interconnection as discrete points of sources and sinks. This rather coarse “granularity” often causes some inaccuracy in IDC flow impact calculations, especially for large control areas. For example, the flow patterns of a bilateral transaction that “sinks” in the American Electric Power control area are quite different if the actual point of receipt is in Ohio versus West Virginia. Because PJM will expand its control area to include a corridor from northern Illinois to the Mid-Atlantic states, some changes to the IDC model will be required to ensure the accuracy of IDC calculations.

To address this issue, NERC, MISO, and PJM are working on various solutions that will either 1.) allow the IDC to calculate the power flows using the PJM LMP dispatch, or 2.) use PJM’s own calculation of flow impacts over a pre-defined set of flowgates, both internal and external to PJM, that would be entered into the IDC, or 3.) use some other method.

The NERC MISO-PJM review team is engaged in discussion of these market expansion issues now, and the Operating Committee plans a special meeting on February 4 to hear the review team’s findings. Given the complexity of the options for integrating the market expansion in the Eastern Interconnection, we don’t expect the OC to decide on a specific course at that meeting.

Finally, it’s important to note that PJM’s market expansion is only the first of many other markets that are now evolving, with no guarantee that future markets will be of the same design. For example, unlike PJM, the control areas under MISO will continue to exist after the MISO begins its market operations. Therefore, NERC must carefully consider how it addresses the reliability impacts of market integration to avoid the need for specific “patches” to its reliability standards or tools (such as the IDC) that handle congestion mitigation procedures.

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1 The Operating Committee’s IDC Granularity Task Force has recommended a redesign of the IDC that will rely on smaller generation and load “zones” rather than control areas. This is one of the issues now before the OC.
NERC-NAESB-RTO Discussions

Action

Endorse the continuation of discussions and negotiation of an agreement to coordinate the efforts of NERC, NAESB, and the RTOs, with the understanding that any agreement reached would be subject to Board approval.

Background

NERC and NAESB have signed a Memorandum of Understanding, effective November 30, 2002, to coordinate their respective standards development activities to eliminate overlap and avoid duplication of efforts.

The Regional Transmission Organizations (RTOs) have indicated an interest in entering into a similar kind of agreement, for the same purposes. RTOs are engaged in certain developmental activity in response to FERC’s requirements for a standard market design. There is the potential for duplication of effort, especially between NAESB and the RTOs, but also for certain of NERC’s activities, if the work of the various groups is not coordinated. The RTOs are in the process of formalizing an “ISO/RTO Council” that would speak for the RTOs and work to develop a coordinated RTO position on various matters. The Chief Information Officers of the ISOs and RTOs have already been working together in this fashion. The RTOs anticipate that other committees will also be formed as needed.

Representatives of NERC, NAESB and the RTOs have met on four occasions over the past two months to discuss the matter and have exchanged working papers. The details of an agreement have not yet been developed. The preliminary ideas under discussion involve expanding the NERC-NAESB MOU to a three-way agreement, with ISO/RTO Council presence on the Joint Interface Committee. As envisioned, an expanded JIC would be of particular value in reviewing and coordinating the annual work plans of the three organizations. That subject is mentioned in the NERC-NAESB MOU, but the mechanism for coordinating annual plans is not specified there.

The representatives are working to complete an agreement by mid-March 2003. FERC has expressed informal but strong support for this effort. March had been FERC’s stated goal for when the industry would have in place mechanisms to coordinate standards development activity related to FERC’s planned standard market design rulemaking. A drafting team has been tasked with circulating a draft agreement by the end of January.
Standards Authorization Committee (SAC) Report

Action
None

Background
The SAC reports to the NERC Board of Trustees and is responsible for overseeing the development of NERC reliability standards. With the addition in January of two members from the “federal, state, and provincial regulatory or other government entities” segment, the SAC now has representation in all industry segments, with one vacant seat.

Since the October 2002 Board meeting, the SAC has held two meetings and several conference calls, and taken the following actions:

1. The chair and vice chair have been elected.
2. Two SARs were authorized to move into the standards drafting phase (Balance Resources and Demand and Operate Within Limits); standards drafting teams were appointed for each by the SAC.
3. Four new SARs dealing with certification of functions identified in NERC’s Functional Model were approved to enter the process. A SAR drafting team has been appointed to begin refining these SARs.
4. Two new SARs requesting modifications to the Standards Development Process Manual were approved to enter the process.
5. A plan has been developed for the completion of SARs currently accepted into the process (attached).

Mr. Ricky Bittle, SAC Chairman, will provide a report of SAC activities and observations from the meetings and conference calls held to date.
## DRAFT Annual Plan for Reliability Standards Development in 2003

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*Note – this schedule presumes that the industry will not support a 60-day posting cycle for draft SARs and draft standards. Security-related standards may be added to this schedule in 2003.*
## Balance Resources and Demand

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### Task Name

#### Develop Op Within Limits Standard
- Solicit Participants for Ballot Pool

#### Draft new standard
- Develop draft standard
- Post draft standard for comment
- Consider Comments & Develop Revised draft
- Post draft standard for comment

#### Analyze Draft Standard
- Analyze comments

#### Ballot New Standard
- Conduct 1st Ballot
- Address Negative Comments
- Conduct 2nd Ballot

#### Adopt Standard
- Post approved standard for BOT action

#### Implement Standard

### Timeline

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**Monitor and Assess Short-term Transmission Reliability – Operate Within Limits**
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## Revision to Standards Process Manual – Step 2

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### Coordinate Operations

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NAESB-NERC Joint Interface Committee (JIC) Report

Action
None

Background
NAESB and NERC signed a Memorandum of Understanding on November 30, 2002 that outlines the manner in which the development of business practices by NAESB will be coordinated with reliability standards developed by NERC. The cornerstone of this agreement is the formation of a joint interface committee (JIC), comprising representatives of both NERC and NAESB, whose primary function is to review proposals for business practices received by NAESB and proposals for reliability standards received by NERC to determine which process (NAESB or NERC) is most appropriate for the development of the proposal.

In late December, NAESB and NERC named their representatives to the JIC. The first meeting of this group was held on January 10, 2003. At this meeting, two proposals for reliability standards were presented by NERC for JIC consideration. It was the unanimous decision of the JIC that both proposals be assigned to the NERC process for development.

Mr. Ricky Bittle, JIC Co-Chairman will provide a report of JIC activities and observations from the first JIC meeting.
Functional Model Update

Action
None

Summary
NERC’s Functional Model provides the foundation for NERC’s new reliability standards by defining the functions necessary to reliably operate and plan the interconnected bulk electric system. When developing the Functional Model in 2001, NERC recognized that the model’s functions, definitions, and interrelationships might need to be adjusted in the event that the model could not accommodate all aspects of evolving electricity markets and new market players. NERC now recommends several minor changes to the Functional Model, plus the addition of three new planning functions.

The Functional Model Review Task Group posted version 2 of the NERC Functional Model for public comment on January 7, 2003, with comments due by February 14. Don Benjamin will review the recommended changes with the Board for information.

After reviewing the public comments and obtaining approval at the March standing committee meetings, the revised model will be brought back to the Board for approval.

Background
A number of events during the last two years have prompted NERC to review the Functional Model to make sure its definitions are still appropriate:

1. NERC held workshops in May 2002 seeking industry input on NERC’s proposed organization certification criteria and procedures.
3. The Electronic Scheduling Collaborative issued a set of draft business practice standards.
4. Regional Transmission Organizations continued to form.
5. The NERC Planning Committee developed three planning functions to add to the model.

The Functional Model Review Task Group concludes that the Functional Model, without modification, can accommodate the Standard Market Design proposed by the Federal Energy Regulatory Commission. The model was purposely designed so that it would not rely on any particular market structure.
Recommended Changes to the Functional Model

1. Remove the specification that the balancing authority is the interconnected operations services provider of last resort. The task group does not believe it proper to require the balancing authority to provide these services if they are not available from the marketplace.

2. Allow the interchange authority to schedule directly with a scheduling agent on behalf of one or more balancing authorities. This will allow for balancing authority-to-market or market-to-market bilateral transactions.

3. Reassign the responsibilities for transmission maintenance from the transmission operator function to the transmission owner function.

4. Add three planning functions: 1.) planning authority function, 2.) resource planning function, and 3.) transmission planning function.

5. Split the generator function into separate generator owner and generator operator functions. These two functions were described in Version 1 of the Functional Model, but were commingled in a single generator function definition.

6. Require the transmission operator and planning authority to be NERC certified. Remove the NERC certification requirement from the transmission service provider.

7. Clarify the specifications for all functions based on workshop comments and review.
North American Electric Reliability Council  
Treasurer's Report  
From 1/1/2002 Through 12/31/2002

(In Whole Dollars)

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| Net Change in Assets      | 331,248     | (66,813)    | 398,061  | 1,314,687   |

¹ 2002 Capital purchases were $173,450

Note: Final report is subject to change based on results of audit by Druker, Rahl, & Fein
North American Electric Reliability Council  
Treasurer's Report  
From 1/1/2002 Through 12/31/2002

(In Whole Dollars)

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<td>Net Change in Assets</td>
<td>331,248</td>
<td>(233,290)</td>
<td>288,928</td>
<td>467,290</td>
<td>(191,680)</td>
</tr>
</tbody>
</table>

\(^1\) 2002 Capital purchases were $173,450

Note: Final report is subject to change based on results of audit by Druker, Rahl, & Fein
TO: NERC BOARD OF TRUSTEES

Ladies and Gentlemen:

Notice of Compliance

The undersigned certifies that the information provided below is complete and accurately reflects the state of compliance of the Corporation pertaining to the following:

As of December 31, 2002, the Corporation has withheld all amounts required to be withheld as required by the IRS and has paid all salaries, wages, pension benefits, vacation benefits, retirement allowances and required retirement plan contributions.

All required source deductions payable for the above items are up to date.

Sincerely,

Joseph K. Conner, Jr.
Treasurer and Chief Financial Officer
Reliability Legislation

Action
None

Background
Leaders in both the House and the Senate have indicated they will take up energy legislation, including an electricity title, early in the 108th Congress. Reliability language will be included. By the time the conference committee adjourned without producing a bill last Fall, House and Senate negotiators had agreed on reliability language, and that language will be the basis for reliability legislation this year.

We sent a letter to incoming Chairman of the Senate Energy and Natural Resources Committee, Senator Pete Domenici (who was not involved in the negotiations last Fall), on behalf of NERC, the American Public Power Association, the Canadian Electricity Association, the Edison Electric Institute, the Institute of Electrical and Electronic Engineers-USA, the National Association of Regulatory Utility Commissioners, the National Association of State Utility Consumer Advocates, the National Rural Electric Cooperative Association, the Western Governors Association, and the Western Electricity Coordinating Council, urging passage of reliability legislation this year.

We have had discussions with key committee staff members in both the House and the Senate. We provided additional language to both the House and the Senate that addresses the “regional entity governance” issue that arose during the conference committee deliberations last Fall. The change clarifies that regional entities with delegated enforcement authority are not required to have independent boards of directors, ensuring that the legislation is consistent with the intent of the original NERC language. House staff informed us that the Committee plans, as a starting point, to introduce without change the language that was contained in the final offer made by the House conferees as its new bill. Staff is not opposed to our revision, although we are still working through questions with them, but the instructions from the leadership were to introduce the House offer without change as the starting point.

Separately, Congressman Wynn (D- MD) and Congressman Burr (R – NC) are planning to introduce electricity legislation patterned on H.R. 2814 (the Sawyer bill) from the last Congress. H.R. 2814 contained the original, long version of the reliability legislation. We have convinced them to substitute in their new bill the reliability language from the final House offer, modified to include the “regional entity governance” fix. We expect that bill to be introduced as soon as the House reconvenes for the State of the Union address on January 27, 2003.

The Senate has not been as specific about its plans. Chairman Domenici has said that he expects to hold hearings on energy legislation and develop a bill in committee, in contrast to how the bill was handled in the Senate last year. Senator Thomas, who successfully sponsored the reliability amendment on the floor of the Senate last year, remains on the Energy Committee, and we expect him to be equally helpful this year.
Agenda Item 20a
BOT Meeting
February 11, 2003

Standard Electricity Market Design

Action
None

Background
On July 31, 2002, the Federal Energy Regulatory Commission (FERC) issued a “Notice of Proposed Rulemaking Remedying Undue Discrimination Through Open Access Transmission Service and Standard Electricity Market Design” (SMD NOPR) (Docket No. RM01-12-000). The SMD NOPR proposes to restructure wholesale electricity markets and raises both reliability and critical infrastructure protection issues that require NERC review and comment. At its October 8, 2002, meeting, the Board unanimously approved NERC’s process and schedule for finalizing and approving NERC’s comments. The draft comments were posted for public comment from October 21–November 1. The Board reviewed and approved NERC’s final SMD NOPR comments via conference call on November 12, 2002.

NERC Actions Taken
On November 15, 2002, NERC filed comments with FERC. The comments were divided into two parts: those that addressed reliability issues and those that focused on security concerns.

NERC’s reliability comments addressed five key issues:

1. Ensuring that independence of the Independent Transmission Provider (ITP) is clarified and that the reliability functions that the ITP will be responsible for providing under the NERC Functional Model are clearly identified.
2. Ensuring that parallel flow impacts between ITPs are coordinated, that curtailment priorities are clarified, and that a backstop congestion management procedure is in place prior to the implementation of SMD.
3. Ensuring that the relationships between interconnected operations services and the ancillary services are clarified, and that all ancillary services necessary for the reliable operation of the grid are correctly identified and included in the SMD.
4. Ensuring that any resource adequacy requirements will ensure an adequate and reliable bulk electric system.
5. Ensuring that the methods used to assess transmission capacity and uses are consistent with established design and operating criteria.

NERC’s NOPR response schedule included the consideration of preparing and filing reply comments on these issues. NERC staff have reviewed the majority of comments filed in this proceeding. Many of the comments filed were supportive of and/or consistent with NERC’s comments. Although unanimity of opinion was not observed, none of the comments filed on these issues were deemed to require NERC to file reply comments at this time.
The Critical Infrastructure Protection Advisory Group worked closely with FERC in the development of the cyber security standards included in the SMD NOPR. CIPAG provided additional comments on the proposed cyber security standards, and these comments were made part of the NERC comments that the Board approved. These comments were also discussed at a FERC workshop in December and were largely accepted as an appropriate start to providing the security envisioned in the NOPR. NERC staff has reviewed the comments filed on the cyber security portion of the SMD NOPR and determined that reply comments are not required at this time.

**Future Actions**

FERC has indicated that it will issue a white paper further clarifying its proposed market design rules in April. FERC will take comments on the white paper and expects to issue a final rulemaking in July 2003. NERC will continue to monitor reliability issues in the emerging rule on standard market design and may find it appropriate to file additional comments in this proceeding.

NERC is awaiting a decision on whether FERC will separate the cyber security standards from the remaining market design issues and issue a separate cyber security rule. At a technical conference scheduled for February 4, 2003, FERC is expected to provide the industry with additional guidance on this issue. One issue that arose at the December technical conference is how to assure compliance with the cyber security standards. Some parties suggested that NERC could include the cyber security standards as part of its compliance program. FERC has invited David Hilt, NERC Director of Compliance, to describe the NERC compliance program at the February 4 workshop.

Kevin Perry, CIPAG chairman, and several CIPAG members will also be present at the conference.
Standardization of Small Generator Interconnection Agreements and Procedures

Action
None

Background
On August 16, 2002, the Federal Energy Regulatory Commission (FERC) issued an “Advance Notice of Proposed Rulemaking (ANOPR) on Standardization of Small Generator Interconnection Agreements and Procedures” (Docket No. RM02-12-000). Because certain aspects of the ANOPR are closely related to the development and implementation of industry standards for planning and operating reliably the interconnected bulk electric systems of North America, NERC asked for and received the Board’s approval at its October 8, 2002 meeting to file comments in this proceeding.

A key presumption of the small generator interconnection ANOPR is that criteria can be established by which it can be determined that a small generator nominally has “no impact” on the electric system. The smallest of generators (up to 2 MW) would be allowed to use a super-expedited process that relies on pre-certification of various manufacturers’ self-contained generator packages. Generators larger than 2 MW and up to 20 MW would have an expedited process, but rely on screening criteria to ensure the generator (or generators in aggregate) do not adversely affect the bulk electric system, the local distribution system, or other customers.

NERC Actions Taken
The Planning Standards Subcommittee completed an initial review of the draft small generator interconnection documents, resulting in comments that were filed with FERC in December 2002. In its comments, NERC requested the Commission to allow deliberate review of reliability issues in the NOPR process, pointing out several reliability or safety issues of note:

- Sufficiency of screens for determining “no reliability impact”
- Effects of aggregating small generators and the complications of studying the effects of multiple generators in the queue that may or may not be installed
- Need to use relevant generator models based on industry practice
- Reference to NERC and Regional Reliability Council reliability standards
- Need for communication with system operators to ensure operational safety
- Need to consider overvoltage conditions when a generator is isolated with a part of the distribution system due to a breaker trip

Future Actions
The Planning Committee, assisted by NERC staff, continues to monitor the reliability implications of emerging rules on small generator interconnections (Docket No. RM02-12-000), as well as the issuance of a final rule on Standardization of Generator Interconnection Agreements and Procedures (Docket No. RM02-1-000).

NERC may find it appropriate to file additional comments in these proceedings.