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President and CEO

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL

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

August 29, 2003

Honorable W.J. Tauzin
Chairman, Committee on Energy and Commerce
Room 2125 RHOB
United States House of Representatives
Washington, D.C. 20515

Dear Chairman Tauzin:

The North American Electric Reliability Council (“NERC”) is pleased to provide responses to the questions you posed on August 19, 2003, concerning the August 14th blackout in the upper Midwest and Northeast United States and eastern Canada.

(1) What were the basic causes and contributing events that led to the August 14th blackout and its severity? Describe the following in your answer:

- (a) the location, character and proximate cause of the initial disruption in the transmission and supply of electricity; and**
- (b) the “cascading” effect of the disruption through multiple utility systems and States.**

The outage on August 14th affected electric systems in the states of Michigan, Ohio, Pennsylvania, New York, New Jersey, Vermont, Massachusetts, and Connecticut, as well as the province of Ontario, Canada. NERC technical staff along with people from the Consortium for Electric Reliability Technology Solutions (“CERTS”), acting as the designated representative of the U.S. Department of Energy (“DOE”), have been jointly conducting a fact-finding investigation of the events leading up to the August 14th blackout. The investigation is ongoing, and no causal conclusions can yet be drawn. DOE is a part of the United States — Canada Joint Task Force on the Power Outage. NERC has provided its information to DOE in support of the Joint Task Force effort. DOE has requested, and NERC has agreed, that DOE, as a member of that Joint Task Force, will coordinate release of that information.

Joining in the NERC/DOE fact-finding investigation are experts volunteered by utilities and system operating organizations across the United States and Canada, and people from other government agencies. NERC expects that Canadian representatives will soon join the effort as well. NERC is receiving massive amounts of data from the affected systems as well as relevant data from other systems within the Eastern Interconnection. NERC has appointed an expert steering group to guide its part of the investigation, to focus the inquiry and make sure that all of the right questions are being asked. The composition and background of the NERC expert steering group are shown in Attachment A to these responses.

NERC expects that its work will be a key input to the efforts of the Joint Task Force. NERC's work will also enable NERC to fulfill its own requirements to determine what happened, whether violations of NERC rules occurred, whether NERC needs to revise its rules, and what other steps need to be taken to avoid a recurrence. In order for the investigation to be complete, NERC and DOE have requested data from the affected companies starting at 8 a.m. on August 14. This will enable the investigators to form a clear picture of how that day started and what events through the course of the day may have contributed to or set the stage for events later in the day. Because that data is still being accumulated and has not been fully evaluated, it is too soon to determine whether or not events earlier in the day may have contributed in any way to the outage. One focus of the investigation as it goes forward will be why protocols and procedures that exist to prevent problems in one part of the grid from spreading did not prevent the cascading outage across such a wide area.

(2) What efforts have been taken to secure the supply, transmission and distribution of electricity since the blackouts of 1965 and 1977 in the Northeast, and why were these efforts apparently inadequate to prevent the blackout or otherwise minimize the area affected? What efforts have been undertaken in other parts of the country to prevent blackouts and how effective have these efforts been in preventing or minimizing blackouts?

NERC was formed in 1968 as a result of the 1965 blackout to help electric utilities better coordinate their planning and operation to prevent such a massive disruption from occurring again. NERC's members include virtually all the investor-owned, municipal/state/provincial, cooperative, and federal electric utilities in the United States, Canada, and a small part of Mexico, plus independent power producers, electric power marketers, and end-use electricity customers. NERC also works closely with the U.S. Department of Energy, the Federal Energy Regulatory Commission, the National Energy Board of Canada, the National Association of Regulatory Utility Commissioners, and industry trade groups.

The nature of NERC's responsibilities, the international makeup of its membership, and the physics of interconnected electric systems demand unity, discipline, and compliance with NERC and regional reliability standards. Currently, these reliability responsibilities are carried out through *voluntary cooperation* and peer review, with virtually no enforcement powers, sanctions, or penalties for non-compliance. This is largely because NERC does not have the statutory authority to enforce compliance with its reliability standards.

Despite its lack of authority, NERC has made every effort to continuously clarify and upgrade its reliability standards as the electric industry has evolved. NERC has also enhanced its monitoring of compliance with its standards by individual entities, independent system operators, and Regional Reliability Councils. NERC has an established peer review process that is conducted through its committees and independent Board of Trustees. NERC uses this process to promote compliance by industry participants with existing reliability standards.

NERC's industry-based standards development and compliance processes have worked reasonably well since NERC was established. Although we do know something went very wrong on August 14, it is too soon to tell whether it is the result of a failure of a particular entity or entities to comply with

NERC standards, whether we did not have in place the kind of standards that would have prevented this blackout from occurring, or whether there were other causes. We are asking these very questions among many others as our investigation into the blackout proceeds.

Attachment B provides a summary of actions that NERC and the electric industry have taken over the past forty years to plan, design, and operate an interconnected, synchronously operated electric grid in a manner that would ensure bulk electric system reliability and avoid cascading outages to the greatest extent possible. These actions were also designed to minimize the areas affected and the destruction of critical electrical equipment should be unplanned outage occur.

(3) What equipment, measures or procedures worked as intended on August 14th to prevent even greater disruption to the supply of electricity, to prevent greater damage to the generation and transmission system, and to bring generation back on line after the disruption?

It is too early to identify specific equipment, measures, or procedures that worked as intended on August 14. In more general terms, however, large parts of the Eastern Interconnection did not suffer the blackout. Protective relays within the distressed area operated to remove transmission lines, transformers, and generating units from service before they suffered physical damage. The system is designed to do that. The fact that the transmission lines, transformers, and generating units did not suffer physical damage is what made it possible to restore the system and service to customers as quickly as happened after the blackout. Another element that worked as intended was the restoration plans themselves. Restoring a system from a blackout requires a very careful choreography of re-energizing transmission lines from generators that were still on line inside the blacked-out area as well as from systems from outside the blacked-out area, restoring station power to the off-line generating units so that they can be restarted, synchronizing those generators to the Interconnection, and then constantly balancing generation and demand as additional units and additional customers are restored to service.

(4) How can the nation's electric system, including both transmission capacity and reliability, be improved to prevent a recurrence of the events of August 14th? Please identify what measures may need to be taken by all involved in the governmental and nongovernmental sectors.

Until more is known about the cause or causes of the August 14th blackout, it is premature to make recommendations on measures needed to prevent a recurrence. Apart from the particulars of the August 14th outage and without knowing whether or not violations of reliability rules occurred then, one important step for Congress to take to strengthen the reliability of the bulk power system in general would be to pass legislation to make the reliability rules mandatory and enforceable. NERC and a broad coalition of industry, governmental, and customer groups have been supporting legislation that would authorize creation of an industry-led self-regulatory organization, subject to oversight by the Federal Energy Regulatory Commission within the United States, to set and enforce reliability rules for the bulk power system. The comprehensive energy bills that have passed both the House and the Senate have versions of that reliability legislation. NERC looks forward to working with the conference committee to achieve passage of that legislation this year.

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I have also been invited to testify on these issues before the Committee on September 3, 2003, and I look forward to discussing these matters further at that time.

Very Truly Yours,

A handwritten signature in black ink, appearing to read "Michael R. Gund", with a long horizontal flourish extending to the right.



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August 14, 2003 Blackout Investigation NERC Steering Group

SCOPE August 27, 2003

Scope

The NERC Steering Group steers the formulation and implementation of the NERC blackout investigation plan, reviews the milestone progress and results, and recommends improvements. The Steering Group provides a perspective of industry experts in power system planning, design, and operation.

Members

The members of the NERC Steering Group are:

Paul F. Barber, Facilitator

Barber Energy

Yakout Mansour

Senior Vice President
System Operations & Asset Management
British Columbia Transmission Corporation

W. Terry Boston

Executive Vice President
Transmission/Power Supply Group
Tennessee Valley Authority

William (Bill) K. Newman

Senior Vice President
Transmission Planning and Operations
Southern Company Services, Inc.

Mark Fidrych

Power Operations Specialist
Western Area Power Administration

Terry M. Winter

President and Chief Executive Officer
California ISO

Sam R. Jones

Chief Operating Officer
Electric Reliability Council of Texas

M. Dale McMaster

Executive Vice President—Operations and
Reliability
Alberta Electric System Operator

Biographies

Paul F. Barber, Ph.D.

Barber Energy

Dr. Barber provides transmission and engineering services to the electric power industry in areas of governance, strategic planning, electric grid management, and power system reliability. He previously served as the Chair of the NERC Market Interface Committee and as the Vice Chair (Transmission Customers) of the Northeast Power Coordinating Council (NPCC). Dr. Barber joined Boston-based Citizens Power & Light, providing transmission and engineering technical expertise and support to all business lines of Citizens Power & Light and its successors. Dr. Barber served on the NERC Board of Trustees as well as the Boards of the Mid-Atlantic Area Council, Western Systems Coordinating Council (WSCC), and the three Regional Transmission Associations in the Western Interconnection. Prior to 1994, Dr. Barber served a 28-year career as an officer in the U.S. Army Corps of Engineers rising to the rank of Colonel. Dr. Barber received his BS degree from the U.S. Military Academy and MS degrees in electrical engineering and civil engineering from the University of Illinois. He completed a Ph.D. degree in electric power engineering from Rensselaer Polytechnic Institute in 1988. He has been registered in the State of Illinois as a professional engineer since 1974.

W. Terry Boston

Executive Vice President, Transmission/Power Supply Group

Tennessee Valley Authority

Terry Boston is Executive Vice President of the Tennessee Valley Authority's Transmission/Power Supply Group. Mr. Boston is the senior officer responsible for the planning, building, operation, and maintenance of TVA's transmission and power supply network. He joined TVA as a power supply engineer in 1972, and was named head of the Power Supply Group in 1980. Over the next 16 years, he directed three TVA divisions in succession: Transmission, Regional Operations, and Electric System Reliability. Mr. Boston has served for six years on the NERC Engineering Committee and Transmission Task Force, and is on the NERC Stakeholders Committee. He is vice president of CIGRE, the International Council on Large Electric Systems, and vice president of CERTS (the Consortium for Electric Reliability Technology Solutions). Boston holds a B.S. in engineering from Tennessee Technological University and an M.S. in engineering administration from the University of Tennessee.

Mark Fidrych

Power Operations Specialist

Western Area Power Administration

Mark E. Fidrych has served as the Manager of Western Area Power Administration's Rocky Mountain Desert Southwest Reliability Center. Mr. Fidrych began his career with WAPA in 1979, working in maintenance and marketing, with the majority of his career having been in power system operations. He directed activities in the computer systems and power scheduling divisions before becoming the Operations Manager in 1990. A 1972 graduate of the University of Rhode Island, Mr. Fidrych received a bachelor's degree in electrical engineering. In 1980, he received a master's degree in public administration from the University of Colorado. Mr. Fidrych is the present Chair of the NERC Operating Committee. He has also served as the Chair of the NERC Security Coordinator and the Operating Reliability Subcommittees.

Sam R. Jones

Chief Operating Officer

Electric Reliability Council of Texas

Sam R. Jones became the first Director of the Electric Reliability Council of Texas (ERCOT) on December 1, 1996. In March 2000, he was appointed as the Executive Vice President and Chief Operating Officer of ERCOT. Prior to joining ERCOT, Mr. Jones was employed by the City of Austin, Texas, Electric Utility for over 35 years. With the City of Austin, he held engineering and management positions in the areas of distribution, transmission, substation, generation and system operations. He was responsible for the development of Austin's first energy control center. He retired from the City of Austin as Director of Generation and Energy Control. He has been active in inter-utility reliability work for over 19 years. He is a two-time past chair of the ERCOT Operating Subcommittee, and a current Vice-Chair of the NERC Operating Committee, and a past chair (or member) of numerous NERC and ERCOT subcommittees and task forces. Mr. Jones has a degree in Electrical Engineering from the University of Texas at Austin and is a Registered Professional Engineer in Texas.

Yakout Mansour
Senior Vice President, System Operations & Asset Management
British Columbia Transmission Corporation

Yakout Mansour is Senior Vice President of System Operations & Asset Management of the British Columbia Transmission Corporation. Previously, he served as the Vice President of the Grid Operations and Inter-Utility Affairs division of BC Hydro, responsible for BC Hydro's transmission, distribution and generation dispatch operations as well as the development of policies and practices related to inter-utility transmission access. Mr. Mansour currently serves as BC Hydro's principal representative and board member on the RTO West filing utilities structure and has been the Canadian representative in the RTO consultation process. Mr. Mansour is a registered Professional Engineer in the Provinces of British Columbia and Alberta with over 30 years experience in power system planning, system and market operation, design and research. He is a Fellow of IEEE, has authored and co-authored over 100 papers and special publications of IEEE and other international professional institutions, has provided training and consulting services around the world, and holds U.S. and Canadian patents.

Dale McMaster, P.Eng.
Executive Vice-President, Operations and Reliability
Alberta Electric System Operator (AESO)

Dale McMaster is Executive Vice-President, Operations and Reliability for the Alberta Electric System Operator (AESO). The AESO integrates the functions of the Power Pool of Alberta, the Transmission Administrator of Alberta, and provincial load settlement. Mr. McMaster's knowledge of system planning and his overall industry experience integrates the AESO's operational and planning areas. As President and System Controller, Mr. McMaster played a key role during the integration of the former Power Pool and the Transmission Administration. Mr. McMaster joined the former Power Pool of Alberta in 1996 as Chief Operations Officer, with responsibility for the system control function, the ongoing development of the Alberta electric energy market, and strategic planning. He is an electrical engineer with more than 25 years of experience in power systems in Canada and abroad. Mr. McMaster received his degree in electrical engineering from the University of Saskatchewan and held a variety of senior management positions at SaskPower, SNC-Lavalin, and Acres International. He is a member of the Association of Professional Engineers, and the Canadian Electricity Association.

William K. Newman
Senior Vice President, Transmission Planning & Operations
Southern Company

William K. Newman began his career with Georgia Power Company in 1966 and progressed through positions of increasing responsibility at Georgia Power for 18 years. In 1984, he assumed the position of General Manager, Power Operations, at Mississippi Power Company, was promoted to Director of Power Delivery in 1988 and named Vice President, Power Generation and Delivery, in 1989. His responsibilities at Mississippi Power Company included the areas of fuels, environmental, generating plants, transmission, and system operations. He transferred to Southern Company Services in 1992 as Vice President, Operating and Planning Services and was named Senior Vice President, Transmission Planning and Operations in 1995. He is responsible for planning and operation of the Southern electric system's network transmission grid in order to provide economic, reliable service to all users. Mr. Newman has served in numerous academic and professional organizations and is currently Chairman, Southeastern Electric Reliability Council. He is a Registered Professional Engineer in the states of Georgia and Mississippi.

Terry M. Winter,
President and Chief Executive Officer
California ISO

Terry M. Winter is President and Chief Executive Officer of the California Independent System Operator (ISO), a position he has held since March 1, 1999. Mr. Winter was formerly Chief Operating Officer of the California ISO, having accepted the position in August 1997. He assisted in developing operations from the ground up and oversaw the integration of the transmission systems of Southern California Edison, Pacific Gas & Electric, and San Diego Gas & Electric when the California ISO assumed control of the state's open market transmission grid on March 31, 1998. Mr. Winter was formerly the Division Manager of San Diego Gas & Electric's power operations. His 21-year career with SDG&E focused on power operations, transmission engineering and project management. Prior to his tenure with SDG&E he worked on electrical transmission and distribution engineering for Arizona's Salt River Project for 10 years. Mr. Winter holds professional engineering licenses in both California and Arizona. Mr. Winter graduated from the University of Idaho with a Bachelor of Science degree in Electrical Engineering.

The North American Electric Reliability Council Response to Questions from the U.S. House of Representatives Committee on Energy and Commerce

Attachment B provides a summary of actions that NERC and the electric industry have taken over the past forty years to plan, design and operate an interconnected, synchronously operated electric grid in a manner that would ensure bulk electric system reliability and security, and avoid cascading outages to the greatest extent possible. These actions were also designed to minimize the areas affected and the destruction of critical electrical equipment should an unplanned outage occur.

1962 — The Interconnected Systems Group (ISG), comprised of utilities located in the Midwest and South, met to prepare for the imminent closure of seven separate interconnections to form the largest synchronized system in the world. The systems to be included were the four regions of the ISG (Northeast Region, Southeast Region, Northwest Region, and Northeast Region), Pennsylvania-New Jersey-Maryland Interconnection, and Canada-U.S. Eastern Interconnection (CANUSE). The Interconnection Coordination Committee (ICC) was formed to study and recommend an informal operations organization for the future. The North American Power Systems Interconnection Committee (NAPSIC) was formed and adopted the recommendations of the ICC. It served as an informal, voluntary organization of operating personnel that included the ISG regions, the four areas that now comprise WSCC and ERCOT.

1965 — A blackout occurred in the northeastern United States and southeastern Ontario, Canada.

1967 — The U.S. Federal Power Commission report on the blackout recommended “A council on power coordination made up of representatives from each of the nation’s Regional coordinating organizations to exchange and disseminate information on Regional coordinating practices to all of the Regional organizations, and to review, discuss, and assist in resolving matters affecting interregional coordination.”

1968 — Twelve Regional and area organizations form the National Electric Reliability Council (NERC) when they sign an agreement on June 1, 1968. On August 19, the chairman of the NERC Executive Board wrote to the NERC Regions appointing an ad hoc committee on operations and an ad hoc committee on planning and coordination to study and recommend the need for other committees for NERC.

1970 — NERC opened its administrative office in New York City on January 1, and in May, moved to Princeton, New Jersey.

Four organizations in the Southeast combine to form the Southeastern Electric Reliability Council. NERC now had nine Regional Councils.

1975 — NERC incorporated as a nonprofit corporation in New Jersey.

1978 — The NERC Board of Trustees agreed on several additional organizational objectives for NERC, including the need to: define and measure reliability, analyze and testify about legislation affecting reliability, study interregional interconnections, communicate with and

educate others about reliability, and collect and publish data on future electricity supply and demand.

1979 — NERC assumed responsibility for collecting and analyzing generator availability data from the Edison Electric Institute's (EEI) Prime Movers Committee. NERC, with support from the Electric Power Institute, restructured EEI's Equipment Availability Data Reporting System to create the Generating Availability Data System (GADS).

NERC approved expanding its activities to address changes in the industry resulting from the passage of the U.S. National Energy Act of 1978. These activities included the development of planning guides for designing bulk electric systems, invitations to utility trade groups to send observers to NERC Board meetings, and adding staff to support expanded technical activities.

1980 — The North American Power Systems Interconnection Committee merged with NERC and became the NERC Operating Committee. The NERC Technical Advisory Committee (TAC) became the NERC Engineering Committee.

1981 — To recognize the Canadian membership in the Regional Councils, NERC changed its name to North American Electric Reliability Council, keeping the acronym NERC.

1983 — Alaska Systems Coordinating Council became NERC's first affiliate member.

1986 — EEI transferred the integrated Hourly Load Data Base to NERC. NERC expanded the database to include all ownership sectors of the electric utility industry.

1987 — At the urging of the United State's National Security Council and Department of Energy, NERC formed the National Electric Security Committee to address potential terrorism and sabotage of the electricity supply system. The group developed a specific program to address this threat.

1990 — Congress passed the Clean Air Act Amendments of 1990. NERC used the GADS database to provide the Energy Information Administration with a summary of forced and planned outages in the 1985-87 period. EPA used the GADS data to set generator unit emission allocation values.

1992 — Congress passed the Energy Policy Act of 1992. The "NERC Amendment" in the Act bars the federal government from ordering transmission service if the order "would unreasonably impair the continued reliability of electric systems affected by the order."

1993 — The Future Role of NERC Task Force, appointed by the Board of Trustees in 1992 to address provisions of the Energy Policy Act of 1992, developed an action plan for maintaining reliability in the future. The resulting report, *NERC 2000*, includes: Policies for Interconnected Systems Operation, Policies for Planning Reliable Bulk Electric Systems, Membership Recommendations, and Policies for Dispute Resolution.

1994 — Legislative and regulatory initiatives directed at the industry encouraged wholesale competition through the participation in the electricity marketplace by many new entities. The Regional Reliability Councils opened their memberships to these new participants including

independent power producers, power marketers, and electricity brokers. The NERC Board added two voting Trustees positions for independent power producers.

NERC developed a set of principles for scheduling electricity interchange transactions — “Agreements in Principle on Scheduled Interchange” — that apply equally to electric utilities, power marketers, and other purchasing-selling entities. These were designed to help maintain reliability as competition in the market place increased.

1995 — The Federal Energy Regulatory Commission issued its Notice of Proposed Rulemaking (NOPR) on Open Access Transmission seeking comments on proposals to encourage a more fully competitive wholesale electric power market. NERC took the lead in addressing the planning and operating reliability aspects of the NOPR and filed a six-point action plan to provide the basis for action by the electric utility industry and FERC.

1. Establish standards for “Available Transfer Capability,”
2. Reflect actual path flows in interchange scheduling to ensure continued reliability
3. Ensure control area operators have clear authority in emergencies,
4. Ensure compliance with NERC rules in a comparable and fair manner,
5. Establish Standards for Interconnected Operations Services, and
6. Ensure that information vital to operational security is shared freely among control areas, but is not available to gain unfair market advantage.

1996 — NERC opened its Board of Trustees and its technical committees to voting participation by all industry segments, including power marketers, and independent power producers. The board accepted the report from Future Role of NERC Task Force and directed the NERC technical committees to develop specific plans and programs necessary to implement the recommendations contained in the report (*Strategic Initiatives for NERC*). Chairman also charged another board task force to develop options to ensure compliance with NERC and Regional Reliability Council protocols.

The NERC Operating Committee put in place several initiatives:

1. Established reliability coordinators within each Regional Reliability Council to coordinate normal and emergency operating procedures.
2. Set standards for exchanging near real-time operating information among control areas and reliability coordinators
3. Created an Interregional Security Network (ISN) — the telecommunications framework for exchanging operating information; NERC instituted NERCNet, a private frame relay to work in conjunction with the ISN.
4. Required each Regional Reliability Council to develop and implement a regional security plan.

1997 — NERC formed the Electric Reliability Panel, an independent body, to recommend how NERC should redefine its vision, functions, governance, and membership to ensure that reliability could be maintained in an increasingly competitive marketplace. The panel’s report called on NERC to restructure itself into a new organization called the North American Electric Reliability Organization (NAERO) that could function as a self-regulating organization with the authority to set, measure, and enforce reliability planning and operating standards.

The board approved NERC’s first Planning Standards, replacing Planning Guides and a “due process” for developing Operating Standards.

NERC developed two coordinated programs to establish standards for the training and qualifications of persons who operate the bulk electric systems of North America — System Operator Certification Program and System Operator Training Accreditation Program.

NERC and Commercial Practices Working Group (an industry group addressing electricity marketplace issues) and NERC Regional Security coordinators worked together to build a more viable and reliable marketplace.

The Operating Committee put into place a Transaction Information System that provides a method for “tagging” all interchange transactions. The tag provides information to identify and track the purchase and sale of electricity so that the reliability of the system can be maintained.

1998 — NERC Board approved the basic elements of a mission and purpose statement for NAERO, defined the composition of NAERO’s Board, and set forth NAERO membership requirements. It also approved key elements of agreements between NAERO and its affiliated Regional Reliability Organizations and approved formation of an Interim Market Interface Committee to review NERC reliability policies and standards for impacts on commercial markets. This Committee is now called the Market Committee. The Board voted in favor of consensus legislative language, which would permit NERC to become a self regulatory organization. In addition, NERC agreed, at the request of the U.S. Deputy Secretary of Energy, to lead the electric industry’s efforts to assess and report on the industry’s readiness to deal with Y2K issues.

1999 — The NERC elected nine independent members to the Board of Trustees to succeed the industry stakeholder board after reliability legislation was enacted in the United States. It also appointed a special steering committee to develop an action plan to implement the next steps in the process of enacting the NERC Consensus Legislative Language on Reliability. Other actions taken:

1. NERC coordinated the electric utility industry’s preparations for the Year 2000 (Y2k).
2. The board disbands the old standing committee and created three new standing committees whose members represent all sectors of the industry
3. NERC initiated standards and compliance procedures and launched a pilot compliance program. Objectives were to test the effectiveness of NERC and Regional compliance review procedures and to test compliance with 22 NERC standards and their associated measurements.
4. NERC initiated a second-generation (electronic) tagging system to avoid problems inherent in e-mail systems and protocols.

5. NERC certified almost 2,400 system operators under its System Operator Certification Program, which tested their understanding of NERC Operating Policies. By 2001, all system operators on duty had to be NERC-certified.
6. NERC initiated a new approach to project management NERC staff would provide technical support and project management to implement the decisions and directives of the respective standing committees.
7. NERC released its *Study on NO_x Rule*, which assessed the potential impact of certain Clean Air Act requirements in the on bulk electric system reliability.

2000 — NERC agreed to serve as the electric utility industry’s primary point of contact with the federal government for issues relating to national security and critical infrastructure protection. As part of this effort, NERC becomes a founding member of the Partnership for Critical Infrastructure Security (PCIS), which coordinates cross-sector initiatives and complements public/private efforts to promote and assure reliable critical infrastructure services. NERC also significantly increased its outreach to government officials in both the US and Canada, reflecting the critical role governments play in the restructuring of the electric utility industry. In addition:

1. NERC and FERC take major step toward improving coordination and communication between the two organizations with the execution of a “Consultation and Communications Protocols,” which calls for increased FERC participation at NERC board and committee meetings and periodic discussions between the FERC Chairman and NERC executives
2. NERC sponsored a long-term planning initiative to address market-reliability interface issues. The issues identified were molded into action plans and approved by the board.
3. Control Area Criteria Task Force defined basic operating reliability functions that can be rolled up into other entities. The concepts discussed in its report will serve as the basis for new operating policies and standards.
4. Board charged the Standards Task Force with recommending changes to the NERC reliability standards and the process used to develop them.
5. NERC Compliance Enforcement Program (CEP) completed the second year of a multi-year phase-in.

2001 — In the absence of legislative authority, nine of the ten Regional Reliability Councils signed an Agreement for Regional Compliance and Enforcement Programs with NERC. The agreements are intended to enforce compliance with NERC reliability rules through contractual means. Although the Agreements are not a substitute for federal legislation, they allow NERC to ensure some measure of compliance with some of the rules.

The NERC Board revised its Bylaws to change its governance to a ten-member Independent Board of Trustees from a 47-member Stakeholder Board, despite the fact that Congress failed to adopt proposed reliability legislation.

NERC passed several resolutions to approve a functional operating model, ensure the independence of the reliability coordinators, and initiated a transition to organization standards.

1. NERC Operating Committee designed a model that defines the basic functions for reliable bulk electric system operations. With these functions defined, NERC can write standards to address each of function. Then, as new organizations — such as regional transmission organizations (RTO), independent system operator (ISO), and independent transmission companies — develop, they will register the functions they perform with NERC and as well as the standards that they will need to comply with.
2. The NERC Compliance Enforcement Program completed audits of all reliability coordinators (RCs) by the end of 2000 that focused on all aspects of RC responsibilities
3. NERC developed a series of new control area criteria, operating policies, and planning standards. The control area criteria establish the requirement for qualification as a NERC-certified control area.
4. The Standards Task Force (STF) was established to redesign the process by which NERC standards are developed. NERC will use the new standards development process to prepare new organization standards.

2002 — NERC continued to work to improve the electric industry’s physical and cyber security and to provide a common point for coordination with the U.S. government by forming the Critical Infrastructure Protection Advisory Group. The Group developed a compendium of security guidelines for the electricity sector for protecting critical facilities against a spectrum of physical and cyber threats and established the Electricity Sector Information Sharing and Analysis Center. It also established a Critical Spare Equipment Database, replacing a smaller, limited database and with support from the U.S. Department of Energy is designing a standardized public key infrastructure implementation plan for the industry. NERC also designed and implemented a new reliability standards development process for the industry.

1. NERC-NAESB Coordination — NERC is responsible for developing reliability standards, while the North American Energy Standards Board (NAESB) develops business practice standards and electronic communications protocols for the wholesale electric industry. In recognition of the close relationship between reliability standards and business practice standards, NERC and NAESB signed a memorandum of understanding that details the coordination between the two organizations. A Joint Interface Committee (JIC), comprising representatives of NERC and NAESB, was created to examine each standard proposal that is submitted to NERC or NAESB to determine which organization should develop the standard.
2. Organization Certification — The functional model identifies the functions that need to be performed to ensure the reliable planning and operation of the grid. Some of the entities that expect to perform these functions will need to be certified, similar to the way control areas are certified today. The new reliability standards will identify reliability responsibilities along with the certification requirements for these functions.
3. Personnel Certification — The System Operator Certification Program was expanded to offer four credentials for specialized testing in the following areas: balancing and interchange, transmission, balancing/interchange and transmission, and reliability

- coordinator. The program provides enhanced individual utility training, self-study workbooks, computer training programs, and support workshops. To date, more than 4,300 individuals have attained a NERC certification credential.
4. Reliability Coordinator Audits — By the end of 2002, the Compliance Enforcement Program (CEP) had audited all NERC reliability coordinators. The audits focused on all aspects of the reliability coordinator responsibilities. Overall, the audit teams found that reliability coordinators are acting effectively and independently to preserve the reliability of the bulk electric system.
 5. NERC, in conjunction with the Consortium for Electric Reliability Technical Solutions (CERTS), developed and implemented an area control error (ACE) and an area interchange error (AIE) real-time monitoring system applications for North America. These applications enable the reliability coordinators to monitor ace-frequency performance and compliance with performance operational guides as well as allow NERC to analyze and assess control data to improve reliability performance.
 6. Assuring the reliability of new generator connections — FERC issued a NOPR on Standardization of Generator Interconnections that included a draft agreement designed to standardize and streamline the generator interconnection process. NERC filed comments suggesting that further work is required to ensure that the reliability requirements outlined in the NOPR are consistent with NERC reliability standards and not affect the reliability of the bulk electric system.
 7. NERC board approves and implements a new process for developing reliability standards. A Standards Authorization Committee is created and a NERC standards director is appointed.

2003 — NERC Board adopted two more electric sector critical infrastructure protection security measures dealing with securing remote access to electronic control and protection systems and threat and incident reporting. The board adopts the first standard to emerge from the new standards development process.

1. The new reliability standards development process receives ANSI-accreditation.
2. NERC receives and process eighteen standard authorization requests. Several standards move into the development phase.
3. NERC adopts a cyber security standard, the first standard to be developed through the new standards development process, approved by the industry and adopted by the board.