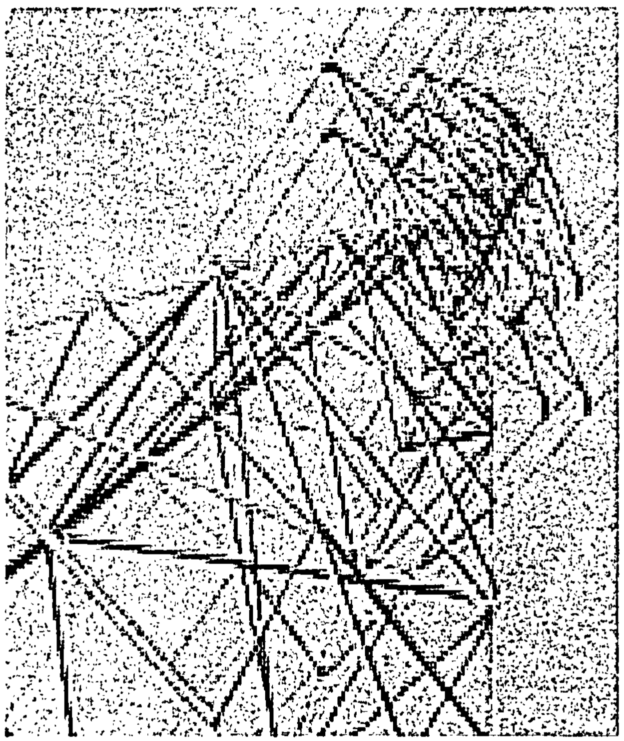
COMMISSION BRIEFING SLIDES/EXHIBITS

BRIEFING ON GRID STABILITY

AND OFFSITE POWER ISSUES

APRIL 26, 2005

FERC's
Division of Reliability



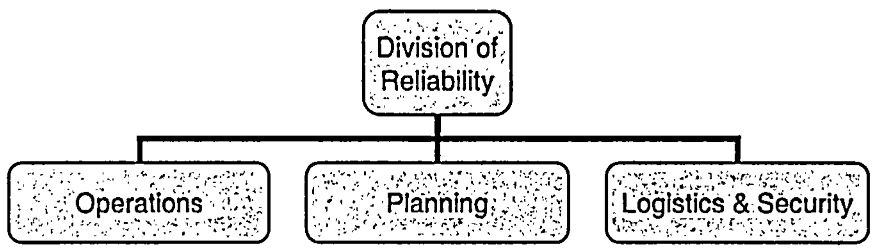
Joseph H. McClelland
Director, Division of Reliability
Office of Markets, Tariffs, and Rates, FERC

FERC's Strategic Plan

- **Chairman Pat Wood moved reliability to the top of FERC's agenda**
- **FERC revised the Strategic Plan to include reliability elements:**
  - recovery of prudent expenses for reliability, security and safety
  - Oversee grid-reliability standards
  - Work with other agencies to improve infrastructure security

Reliability Division

- **The Division is organized into three groups; Planning, Operations, and Logistics and Security**



Some Past Initiatives of the Reliability Group

- Completion of the Blackout Report
- Participation in the Reliability Readiness Review Audits with NERC
- Special investigations and studies
- Tracking and identification of the grid operation functions between entities
- Study and identification of best tools and practices for IT functions

Some Future Initiatives of the Reliability Division

- Cyber security evaluations of Supervisory Control And Data Acquisition (SCADA) systems and IT platforms
- Transmission planning oversight including adequacy and extreme contingency plans
- Spare bulk power supply system equipment studies
- NRC & DHS Studies – outage prediction & Bulk Power Systems (BPS) visualization projects

A Cooperative Effort

- **Common goal of enhancing reliability**
- **We are working in partnership with**
  - Canada and States
  - Other Federal Agencies (DOE, DHS, NRC, etc.)
  - NERC, regional reliability councils and industry stakeholder groups
  - Non-jurisdictional entities
- **Can't be done alone**

Briefing on Grid Stability and Offsite Power Issues
Nuclear Regulatory Commission
April 26, 2005

David R. Nevius, Senior Vice President
North American Electric Reliability Council

Summary Statement

The North American Electric Reliability Council (NERC) is pleased to describe its initiatives and activities on grid reliability and offsite power relative to Nuclear Power Plants (NPPs).

NERC has initiatives underway in three areas that directly relate to the reliability of offsite power to NPPs:

- Reliability Readiness Audits
- Reliability Standard on Coordination of Nuclear Power Plant Licensing Requirements with Bulk Electric System Planning, Analysis, and Operations
- NRC-NERC Memorandum of Agreement

Reliability Readiness Audits

NERC conducts a program to audit the readiness of system operating entities to perform their assigned reliability responsibilities. Initially, these audits focused on deficiencies identified by the August 2003 blackout investigation.

The NERC readiness audits, which are conducted on a three-year cycle, provide independent reviews of system operations capabilities, identify areas for improvement, and highlight examples of excellence. The overall goal of the program is to help operators of the bulk electric system improve their overall reliability readiness by ensuring that they have the tools, processes, and procedures in place to operate reliably.

In cases where an entity being audited is responsible for the offsite power reliability for a NPP, the audit team evaluates the entity's awareness of and readiness to meet the NPP's special offsite power requirements. As part of the audit, the team reviews service level agreements between the NPP and transmission operator, NPP voltage requirement procedures, and critical transmission configurations. Findings to-date are generally good, with several "examples of excellence" identified. All final audit reports are posted on the NERC web site as is our listing of examples of excellence.

Reliability Standard on Coordination of Nuclear Power Plant Licensing Requirements with Bulk Electric System Planning, Analysis, and Operations

NERC is developing a new reliability standard to ensure that the transmission system has the capacity and capability to support the safe operation of NPP safety systems.

The bulk transmission system must be planned and operated in a manner that assures grid voltage, frequency, and stability requirements at the NPP will be met in the event a plant accident occurs, causing a loss of that MW/MVAR generation source and the subsequent application of safety system loads. The NERC standard will require that the electric transmission systems serving the NPP use the NPP-specific licensing and design requirements as the transmission system performance standard, and that these requirements are specified in written agreements between the NPP and the Transmission System Operator.

The standard will include requirements for (1) offsite power to enable safe shutdown of the plant during an electric system or plant event and (2) limiting the challenges to NPP safety systems as a result of an electric system disturbance or transient.

The standard will address coordination of NPP licensing requirements with:

- electric system planning and assessments;
- determination of electric system constraints, including stability requirements;
- electric system operations and maintenance activities; and
- electric system reliability and contingency analysis, including identification of scenarios to be considered.

It will also address:

- consideration of NPP or electric system design changes that may impact the ability to supply acceptable offsite power to the NPP;
- communication and coordination of actions to mitigate off-normal and emergency conditions in the electric system that may affect the NPP;
- communications protocols between NPP licensee and entities responsible for operation and planning of the electric system to address all items above; and
- coordination of NPP licensing requirements that limit challenges to plant safety systems resulting from electric system disturbances or transients.

The standard is currently in the second draft of its standards authorization request (SAR) stage, with comments due May 2, 2005. Following consideration of comments, NERC's Standards Authorization Committee will decide if sufficient consensus exists on the purpose of this standard for it to enter the formal standard drafting stage. A formal ballot on a final standard is expected late this year.

NRC-NERC Memorandum of Agreement

Both the commission and NERC have interest in ensuring the reliable operation of the bulk electric system, and both recognize the importance of working together. At the May 10, 2004 commission meeting on the status of NRC and industry grid initiatives, the commission requested that its staff establish a Memorandum of Agreement (MOA) with NERC. The NERC MOA that was established in August 2004 provides the general terms of cooperation and identified appendices that provide the terms of cooperation in four areas of mutual interest:

I. Communications and information sharing during and immediately following emergencies
II. Specific event investigations and analysis
III. Exchange of operational experience data and information
IV. Participation by NRC staff in NERC committee activities

One area of collaboration that is just getting underway is the joint review and assessment of available grid-related operating experience and data for indications of change, emerging trends, potential vulnerabilities, lessons learned, and indicators that might otherwise be masked by investigating only the operating data for the NPPs themselves. The NRC has routinely analyzed grid reliability based solely on NPP loss of offsite power (LOOP) data, and has not investigated other grid-related operating data. The planned review and assessment will be used to better understand the impact of the availability of offsite power required to ensure safe NPP operation and provide additional insights for NRC and industry consideration.

In Summary

NERC, supported by other industry stakeholders and stakeholder groups, is prepared to continue these initiatives and provide leadership in developing the necessary improvements and coordination. The NEI/INPO/EPRI/NERC workshop held earlier this year in Atlanta is an example of what the industry is doing to address this important issue. It is one in which the industry should appropriately have the lead role.

N A R U C

National Association of Regulatory Utility Commissioners

Commissioner Robert M. Garvin, Public Service Commission of Wisconsin

on Behalf of the

National Association of Regulatory Utility Commissioners

Before the

U.S. Nuclear Regulatory Commission

Remarks on Grid Stability and Offsite Power Issues

April 26, 2005

My name is Robert Garvin. I am a Commissioner at the Public Service Commission of Wisconsin. I serve as Chairman of the Nuclear Subcommittee of the National Association of Regulatory Utility Commissioners (NARUC) and I am testifying today on behalf of NARUC. On behalf of NARUC, I appreciate this opportunity to inform the Nuclear Regulatory Commission of State regulatory commissions' activity in the area of ensuring reliability.

In February of this year (2005), NARUC passed a resolution "calling for state action on mandatory reliability standards." In that resolution, NARUC affirms or recognizes the following:

- States have an obligation to ensure safe, adequate and reliable electric services to retail customers;

- States exercise authority over the siting of transmission and generation facilities, and generation resources and adequacy;

- While in many areas of the country reliability standards are diligently followed, the North American Electric Reliability Council (NERC) and the Regional Reliability Councils (RRCs) operate as voluntary organizations that rely on reciprocity, peer pressure and the mutual self-interest of all those involved to ensure a reliable bulk electric system;

- NERC has a compliance program in place but lacks an enforcement mechanism;

- The U.S.-Canada Power System Outage Task Force's Final Report on the August 14, 2003 Blackout identified seven violations of NERC standards as among the root causes of the blackout, and described its first recommendation as making "reliability standards mandatory and enforceable, with penalties for noncompliance" to prevent future blackouts;

- NARUC continues to support national comprehensive legislation that includes FERC authority to enforce mandatory reliability standards for the bulk electric system that apply to all market participants;

- After seven (7) years of considering the issue, Congress has not passed legislation to make electric reliability standards mandatory;

- Some States have taken action through their regulatory commissions to make electric reliability standards mandatory;

- Some State commissions enforce their orders through penalties, fines or other sanctions; and

- Many States incorporated the National Electric Safety Code and other Institute of Electric and Electronic Engineers (IEEE) standards in their rules governing the operation of electric utilities;

Based on these observations, NARUC resolved to take two actions:

- Encourage States to consider making NERC standards and RRC criteria mandatory for jurisdictional utilities; and

- Develop, by the 2005 Summer Committee Meetings, model orders and legislation which States may use to make NERC reliability standards and RRC criteria mandatory.

To give the Commission a better understanding of the States' involvement in reliability matters, I would like to point out that NARUC actively participates in NERC in several ways. NARUC and the States are active observers of NERC activity. NARUC and seven individuals States are registered as voting members of NERC. The States have two representatives on NERC's Standards Authorization Committee, which develops reliability standards. We have two representatives on NERC's Compliance and Certification Committee, which is the enforcement arm of NERC. The States also have representatives on standing committees of NERC such as the Planning Committee and the Operating Committee. State regulators also participate in regular NERC briefings, held via web-cast. Recent briefings have focused on proposed changes to NERC reliability standards and industry compliance with existing NERC standards. Finally, we have representatives on the NERC Stakeholder Committee. Obviously, NARUC supports NERC fully and we show our support by keeping NERC committees staffed.

I also would like to note that NARUC participates on the North American Electric Standards Board (NAESB). In that capacity, NARUC does its part to ensure that standard business practices do not undermine reliability.

It is also important to note that many States actively ensure reliability at the distribution level. A 2004 survey conducted by the National Regulatory Research Institute (NRRI) under the supervision of Robert Burns summarizes this area of State activity in ensuring reliability. I would like to highlight some of the findings of that survey here to give the Commission an even deeper understanding of the States' involvement in reliability.

NRRI conducted the 2004 NRRI survey between April and October 2004. This survey was a follow-up to an almost identical survey conducted in 2001. In the 2004 survey, forty-one (41) States responded, one more than in 2001.

In response to the 2004 NRRI survey, some States reported new proceedings regarding reliability. Some of this activity is likely the result of a major blackout crippled the Northeastern United States and Canada Aug. 14, 2003. Following the blackout were reports by the Joint U.S.-Canadian Task Force and NERC. In addition, hurricanes caused widespread outages in 2003 and 2004. For example, Oklahoma conducted a reliability rulemaking proceeding in 2004 and Delaware set interim reliability standards through 2005.

According to the NRRI survey, several States have formal standards on reliability and service quality. In fact, twenty-four (24) States require reporting and monitor reliability and service quality. Twenty-one (21) States have performance standards. Fifteen (15) States have established penalties for failing to meet standards and/or rewards for meeting standards. The survey found that most States' performance benchmarks are utility-specific, although Illinois and New Mexico reported uniform, statewide benchmarks. In response to the survey, Kansas stated that there is insufficient conforming data to establish meaningful standards. In addition, Iowa responded that while it has no benchmarks now, it plans to gather five (5) years of data and then review standards. Typically, States that have performance benchmarks use historical data to set those benchmarks.

Many States have specific requirements for tree trimming. Most States responding to the NRRI survey cited their adoption of the National Electric Safety Code with respect to tree trimming.

The States also have different power outage reporting requirements. For example, twenty-five (25) States require utilities to report the cause or causes of outages. Twenty-three (23) States require reports on the number of customers affected by an outage. Twenty-six (26) require reporting on outage duration. Also, three (3) States require media coverage of power outages.

Thirteen (13) States reported that they have specific power quality standards. Severn (7) States reported that they account for service quality in performance-based or incentive ratemaking mechanisms, which was two more States than in 2001.

In summary, the 2004 NRRI survey found an increase in State activity regarding reliability over 2001 levels. More States are using performance standards to ensure and improve reliability and service quality. In particular, more States, although it is still a minority of States, use targeted financial penalties and/or rewards to ensure reliable service.

This concludes my testimony. Again, NARUC appreciates the opportunity to inform the Commission of the States' efforts to ensure reliability.

Nuclear Power Plant / Grid Interface Issues

NRC Commissioners Public Meeting

April 26, 2005

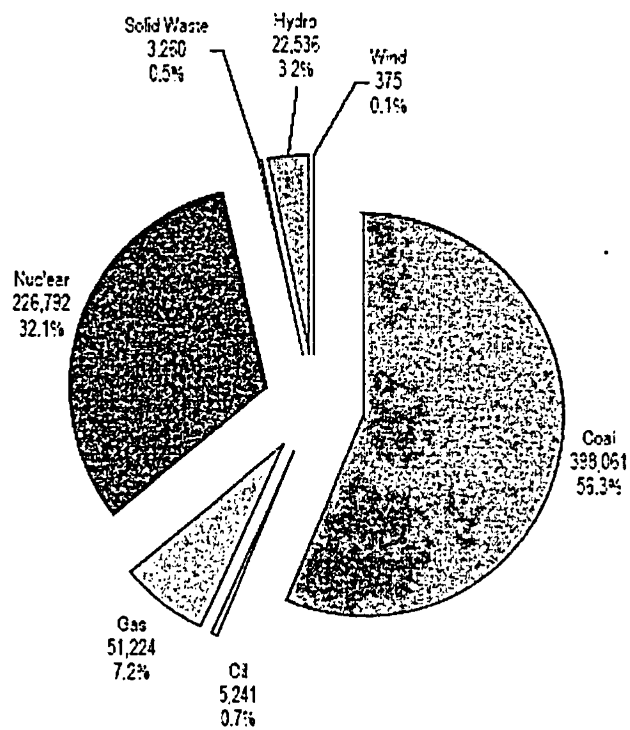
- May 1, 2004 – Commonwealth Edison
  - Installation of a 500 MW pathway between ComEd and existing PJM control areas (= 2 control areas)
- October 1, 2004 – AEP and Dayton Power and Light
  - Removal of pathway and consolidation of the control areas to one control area
- January 1, 2005 – Duquesne Light
  - Inclusion of FE Beaver Valley as a capacity resource in PJM
- May 1, 2005 – Dominion Virginia Power

Overview of PJM—Energy Market Statistics

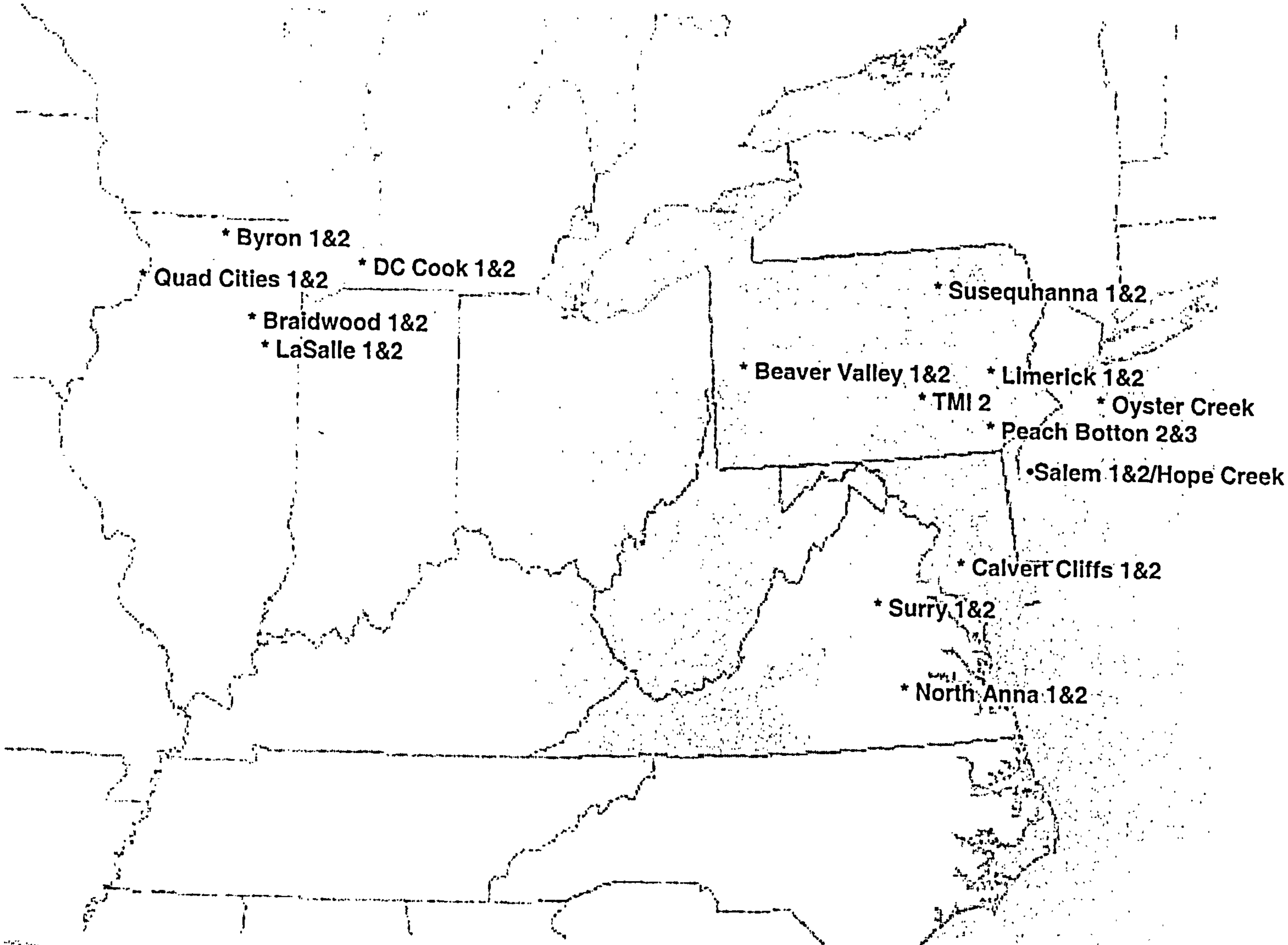
KEY STATISTICS*	PJM	PJM *Jan. 1 with Duquesne Light*
millions of people served	44	45.3
peak load in megawatts	107,820	110,700
megawatts of generating capacity	134,250	137,490
miles of transmission lines	49,300	49,970
generation sources	984	1001
square miles of territory	137,700	138,510
area served	12 states + D.C.	12 states + D.C.

*numbers are approximate

Generation By Fuel Source (GWH)



Overview of PJM—Nuclear Plants



- Created by the owners as a feature of PJM governance (PJM staff facilitates and provides administrative support)
- Broad participation from the nuclear owners: AEP, AmerGen, Constellation, Dominion, Exelon, First Energy, PPL, and PSEG

- "Cultural" Differences
  - Communications (Don't speak the same language)
  - Have differing regulatory accountabilities (FERC vs. NRC vs. State PUCs)
  - Market role (Code of Conduct issues)

Nuclear Communications Protocol (PJM Manual M-1, Attachment B)

http://www.pjm.com/contributions/pjm-manuals/pdf/m01v08.pdf

Features:

- Nuclear Safety/ Grid Reliability Philosophies
- Roles and Responsibilities
- Key Terms Defined
- Event Communications
- Regulatory Background Information

- Post-contingency Voltage Stability
  - NPPs generally have more restrictive voltage limits than the grid
  - In an accident scenario, will the safety systems work if needed?

Notification and Mitigation Protocols for Nuclear Plant Voltage Limits (PJM Manual M-3, Section 3, page 36)

http://www.pjm.com/contributions/pjm-manuals/pdf/m03v14.pdf

Regarding Code of Conduct issues:

"If PJM operators observe voltage violations or anticipate voltage violations (pre or post-contingency) at any nuclear stations; PJM operators are permitted to provide the nuclear plant with the actual voltage at that location, the post-contingency voltage at that location (if appropriate) and limiting contingency causing the violation."

Example of Voltage Standards and Operational Philosophy

PJM BASE LINE VOLTAGE LIMITS

PJM Base Line Voltage Limits						
Limit	500 kV	345 kV	230 kV	138 kV	115 kV	69 kV
High	550 (1.10)	362 (1.05)	242 (1.05)	145 (1.05)	121 (1.05)	72.5 (1.05)
Normal Low	500 (1.00)	328 (.95)	219 (.95)	131 (.95)	109 (.95)	65.5 (.95)
Emergency Low*	485 (.97)	317 (.92)	212 (.92)	127 (.92)	106 (.92)	63.5 (.92)
Load Dump*	475 (.95)	310 (.90)	207 (.90)	124 (.90)	103 (.90)	62 (.90)
Voltage Drop Warning*	2.5%					
Voltage Drop Violation*	5-8%**					

* Refer to PJM Manual for Emergen

** The voltage drop violation percent

Exhibit 5: P

The following chart details PJM's Voltage Operating Guidelines for a Post-Contingency Simulated Operation.

Voltage Limit Exceeded	If post contingency simulated voltage limits are violated	Time to correct (minutes)
High Voltage	Use all effective non-cost and off-cost actions.	30 minutes
Normal Low	Use all effective non-cost actions.	Not applicable
Emergency Low	Use all effective non-cost actions, off-cost actions, and emergency procedures except load shed.	15 minutes
Load Dump Low	All of the above plus shed load if analysis indicates the potential for a voltage collapse.	5 minutes
Voltage Drop Warning	Use all effective non-cost actions.	Not applicable
Voltage Drop Violation	All effective non-cost and off-cost actions plus shed load if analysis indicates the potential for a voltage collapse.	15 minutes

- Outage Coordination
  - *NPP perspective*: Getting the transmission owner to perform maintenance when the NPP is in an outage to mitigate NPP risk
  - *Transmission perspective*: We don't schedule maintenance the way *they* do.

Outage Coordination Procedures (PJM Manual M-3, Section 4) Same link as above

- Strict advanced notification requirements
- Multiple step analysis process to ensure reliability is maintained
- Wide dissemination of outage information

Special Consideration for Nuclear Plants

The Nuclear Generating Stations coordinate the scheduling of a Unit Breaker outage and internal plant equipment outages and testing to minimize station risk. Adherence to outage schedule and duration is critical to the plant during these evolutions. Emergent plant or transmission system conditions may require schedule adjustments, which should be minimized. Any change to the outage schedule that impacts the Unit Breakers shall be communicated to the nuclear generator operator. The following Nuclear Generating Stations have transmission system connections that can impact Nuclear Station Safety Systems:

Peach Bottom:
Unit 2: CB 215
CB 225
Unit 3: CB 15
CB 65

Salem:
Unit 1: 5 – 6 B.S. 10X
2 – 6 B.S. 11X
Unit 2: 9 – 10 B.S. 30X
1 – 9 B.S. 32X

Hope Creek:
BS 6 – 5 50X
BS 2 – 6 52X

Limerick:
Unit 1: CB 535
CB 635
Unit 2: CB 235
CB 335

Oyster Creek:
GD1
GC1

Calvert Cliffs:
Unit 1: 552 – 22
552 – 23
Unit 2: 552 – 61
552 - 63

Grid Reliability: Nuclear Industry Perspectives and Improvements

Gary Leidich,
President and Chief Nuclear Officer
FirstEnergy Nuclear Operating Company

NEI

ACRONYMS

- DOE – Department of Energy
- EEI – Edison Electric Institute
- EPRI – Electric Power Research Institute
- FERC – Federal Energy Regulatory Commission
- INPO – Institute of Nuclear Power Operations
- NEI – Nuclear Energy Institute
- NERC – North American Electric Reliability Council
- SOER – Significant Operating Experience Report

Objective

- Understand "what is important" – nuclear safety
- Discuss industry activities
- Integration and coordination

NEI

Historical Perspective

- Reliability Councils
- Transmission reinforcements
- Use of the transmission system
- Current events

NEI

Industry Activities

- INPO Review Visits: SOER 99-01
  - Interface agreements
  - Loss or degradation of the grid: impacts, evaluations and procedures
  - Grid reliability and stability design assumptions
  - Operator training
  - Operating experience

NEI

Industry Activities (cont'd)

- Coordination improvements
  - Standard authorization request to NERC
  - Atlanta workshop
  - Event reviews
  - NRC collaboration
  - Industry task force

NEI

Utility Actions

- Heightened awareness offsite power events
- Enhancements
  - Transmission control systems
  - Line and station maintenance
  - Communication protocols
- Code of Conduct issues

NEI

Industry Activities (cont'd)

- Industry Task Force
  - Survey of recent loss of offsite power events & impact on plant licensing basis
  - Engage NRC staff
  - Coordinate comments to NRC draft generic letter
  - Monitor NERC activities
    - Standards & audits

NEI

Integration & Coordination

- Key Stakeholders
  - EEI, EPRI, INPO, NEI
  - DOE
  - FERC
  - NERC
  - REGIONAL COUNCILS

NEI

Summary

- Clarity and coordination
- Increased Awareness
- Reliability has improved
- Nuclear plant safety and operational readiness is maintained

NEI

GRID RELIABILITY

April 26, 2005

Acronyms

- **ASP-Accident Sequence Precursor**
- **CCF-Common Cause Failure**
- **CDF-Core Damage Frequency**
- **DHS-Department of Homeland Security**
- **EDG-Emergency Diesel Generator**
- **EPRI-Electric Power Research Institute**
- **FERC-Federal Energy Regulatory Commission**
- **INPO-Institute of Nuclear Power Operations**

Acronyms

- LOCA-Loss of Coolant Accident
- LOOP-Loss of Offsite Power
- NARUC-National Association of Regulatory Commissioners
- NEI-Nuclear Energy Institute
- NERC-North American Electric Reliability Council
- NPP-Nuclear Power Plant

Acronyms

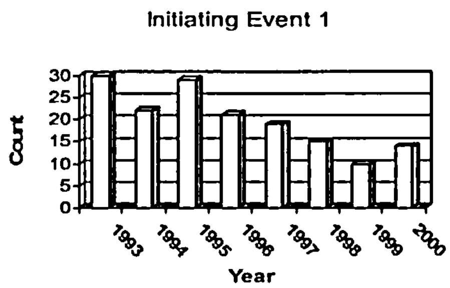
- RCP-Reactor Coolant Pump
- SBO-Station Blackout
- SPAR-Standardized Plant Analysis Risk
- TDP-Turbine Driven Pump
- TI-Temporary Instruction

Grid Reliability Concerns

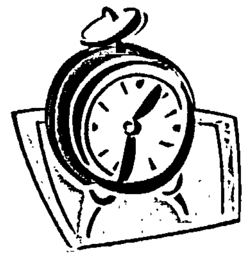
- August 14, 2003 Blackout Event
- Station Blackout Risk Analysis Results
- NRC Actions to Address Grid Safety

LOOP and SBO Risk Factors

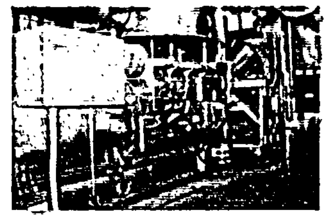
LOOP Frequencies



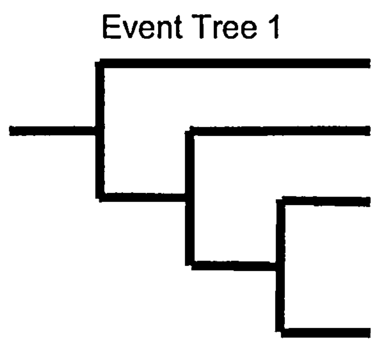
LOOP Durations



EDG Reliability



72 SPAR Models

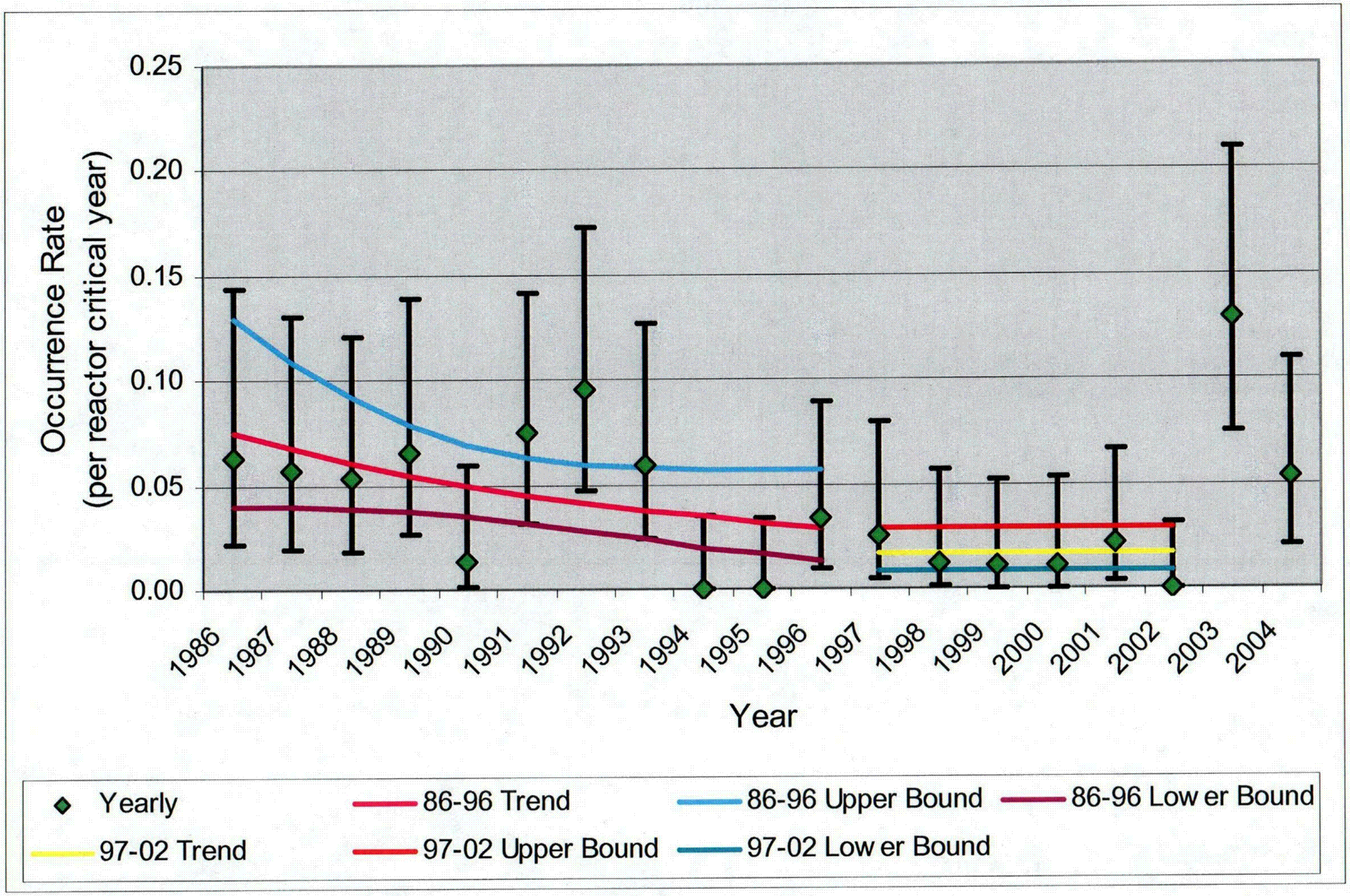


Plant-Specific SBO Coping Features

- Battery depletion time
- Turbine-driven pumps
- Alternate AC power sources
- RCP seal design

SBO Core Damage Frequency

Annual LOOP Frequency
(Power Operation)

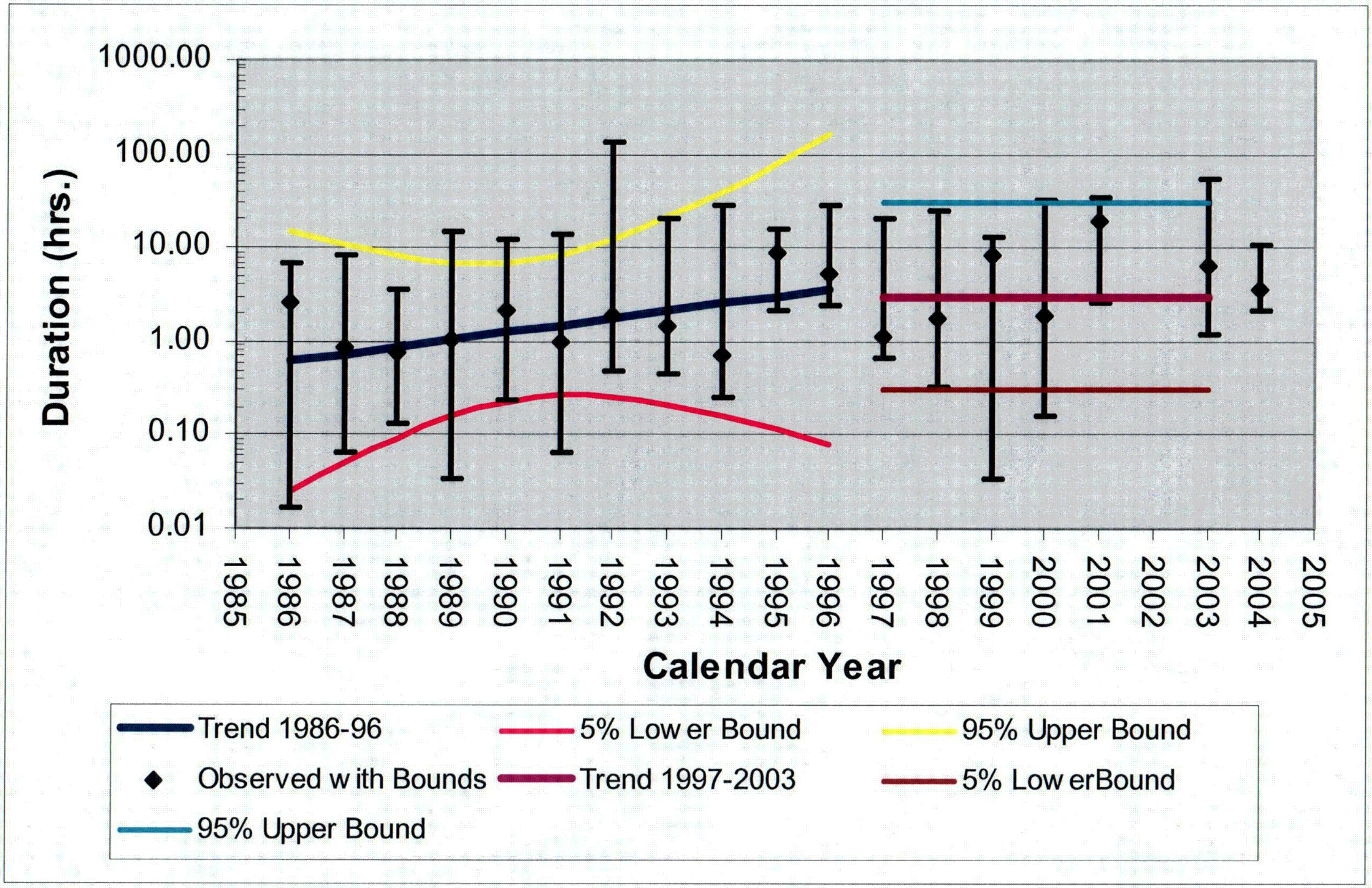


C01

LOOP Frequency Observations

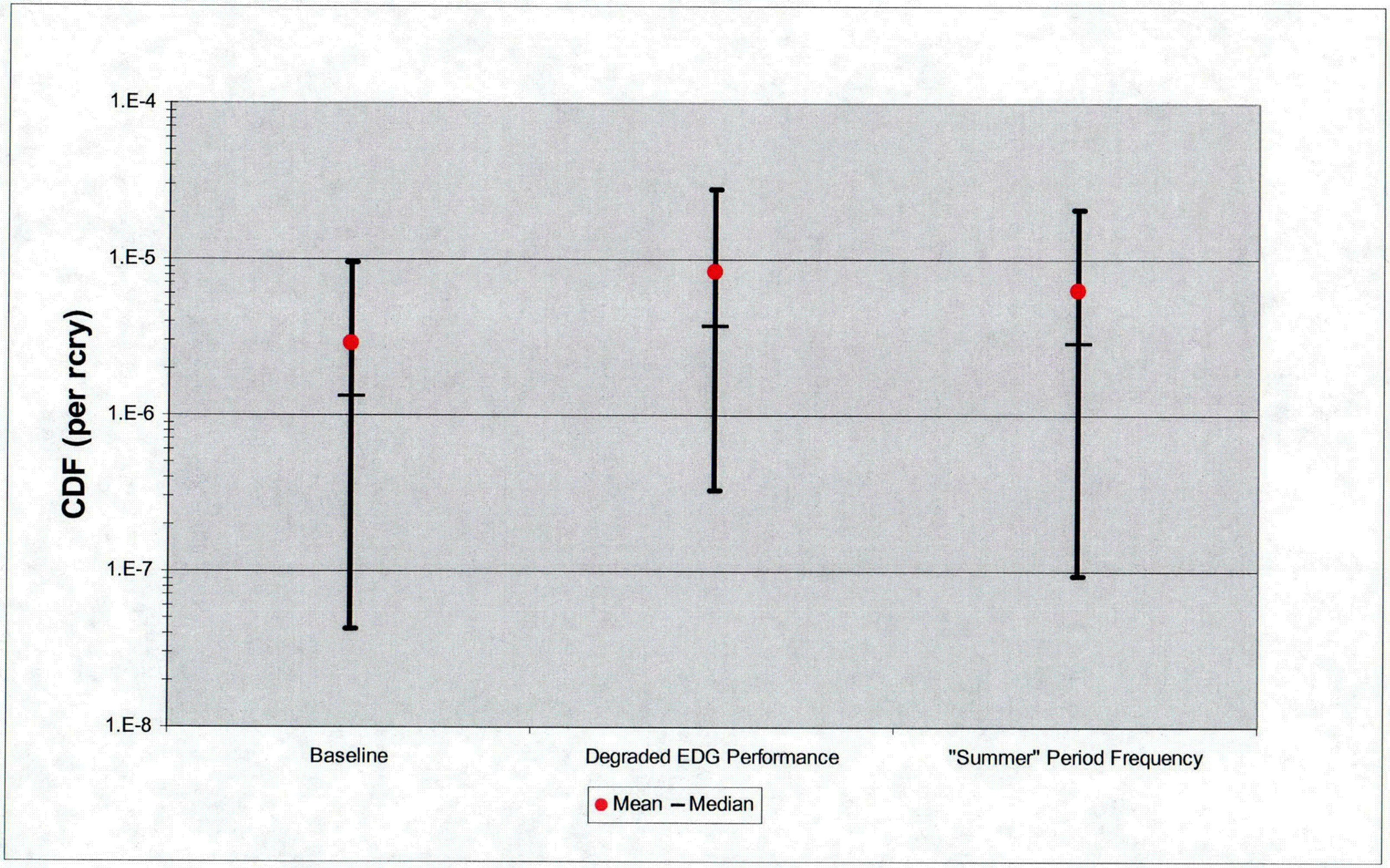
- 19 LOOP events between 1997 and 2003; 17 during the "summer" period
- No grid-related LOOP events between 1997 and 2002; 13 in 2003 and 2004
- Decrease in plant and switchyard centered LOOP events and increase in grid-related LOOP events

Annual LOOP Duration



C02

SBO CDF Sensitivity Results



C03

SBO Risk Perspectives

- Using data from 1997 to 2003, SBO risk was low
- The grid is the largest contributor to SBO CDF
- The increasing number of LOOP events in 2003 and 2004 and their concentration during the summer period are causes of concern

STAFF ACTIONS

- Issued the draft Generic Letter for public comment on April 12, 2005
- Regulatory Bases
  - General Design Criterion (GDC) 17, "Electric power systems"
  - 10 CFR 50.63, "Loss of all alternating current power"
  - 10 CFR 50.65, Maintenance Rule
  - Plant Technical Specifications

STAFF ACTIONS

- **Memorandum of Agreements with NERC and FERC**
- **Interaction with External Stakeholders**
  - **NRC/NERC/FERC are evaluating grid operating data**
  - **Continue to inform the Department of Homeland Security of NRC grid-related efforts**

STAFF ACTIONS

- **Continuing attention of the grid will be needed**

- **Temporary Instruction for Summer 2005**

Conclusion

- **Increasing number and duration of LOOP events is a concern**
- **Draft generic letter raises industry awareness of compliance**
- **NRC communications improved**
- **TI Inspection to check readiness for Summer 2005**