KEEPING THE LIGHTS ON: REMOVING BARRIERS TO TECHNOLOGY TO PREVENT BLACKOUTS

HEARING

BEFORE THE

SUBCOMMITTEE ON ENERGY

COMMITTEE ON SCIENCE

HOUSE OF REPRESENTATIVES

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KEEPING THE LIGHTS ON: REMOVING BARRIERS TO TECHNOLOGY TO PREVENT BLACKOUTS

THURSDAY, SEPTEMBER 25, 2003

HOUSE OF REPRESENTATIVES,
SUBCOMMITTEE ON ENERGY,
COMMITTEE ON SCIENCE,
Washington, DC.

The Subcommittee met, pursuant to call, at 10:06 a.m., in Room 2318 of the Rayburn House Office Building, Hon. Judy Biggert [Chairwoman of the Subcommittee] presiding.

COMMITTEE ON SCIENCE
SUBCOMMITTEE ON ENERGY
U.S. HOUSE OF REPRESENTATIVES

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HEARING CHARTER

SUBCOMMITTEE ON ENERGY
COMMITTEE ON SCIENCE
U.S. HOUSE OF REPRESENTATIVES

Keeping the Lights On: Removing Barriers to Technology to Prevent Blackouts

THURSDAY, SEPTEMBER 25, 2003
10:00 A.M.–12:00 P.M.
2318 RAYBURN HOUSE OFFICE BUILDING

1. Purpose

On Thursday, September 25, 2003 at 10:00 a.m., the Energy Subcommittee of the House Committee on Science will hold a hearing to examine the role of technology in preventing future blackouts and the current economic, regulatory and technical barriers to improved reliability. The hearing will also examine the role of the Department of Energy's (DOE) newly established Office of Electric Transmission and Distribution in enhancing the power grid's performance and reliability.

2. Witnesses

The following witnesses will testify at the hearing:

Mr. James W. Glotfelty is the Director of the U.S. Department of Energy's Office of Electric Transmission and Distribution. Previously, Mr. Glotfelty served as a senior advisor to the Secretary of Energy, where he was a co-leader in the Department's contribution to the National Energy Plan. Mr. Glotfelty also served as an advisor on electricity to then-Governor Bush.

Mr. T.J. Glauthier is the President and Chief Executive Officer of the Electricity Innovation Institute, a new non-profit affiliate of the utility industry's research consortium (Electric Power Research Institute or EPRI). Prior to joining the Institute, Mr. Glauthier was the Deputy Secretary and Chief Operating Officer of the Department of Energy and he served for five years at the Office of Management and Budget as the Associate Director for Natural Resources, Energy and Science.

Mr. Thomas R. Casten is the founding Chairman and CEO of Private Power LLC, an independent power company in Oak Brook, IL, which focuses on developing power plants that utilize waste heat and waste fuel. Mr. Casten also serves on the board of the American Council for an Energy-Efficient Economy (ACEEE), the board of the Center for Inquiry, and the Fuel Cell Energy Board. He is also the Chairman of the World Alliance for Decentralized Energy (WADE), an alliance of national and regional combined heat and power associations, wind, photovoltaic and biomass organizations and various foundations and government agencies seeking to mitigate climate change by increasing the fossil efficiency of heat and power generation. Prior to Private Power LLC, Mr. Casten served as President of the International District Energy Association and he received the Norman R. Taylor Award for distinguished achievement and contributions to the industry.

Dr. Vernon L. Smith is a Professor of Economics and Law and the Director of the Interdisciplinary Center for Economic Science at George Mason University. Dr. Smith, who won the Nobel Prize in economics in 2002, is widely recognized as the 'father of experimental economics' and his current research focuses on the design and testing of markets for electric power, water, spectrum licenses and public goods as well as continuing behavioral and evolutionary research on trust and reciprocity.

3. Overarching Questions

The hearing will focus on several overarching questions:

- Which technologies have the greatest potential to increase the reliability and the efficiency of the U.S. electrical system both now and in the future? How do the costs and benefits of these different technologies compare?

- What technologies are the DOE's Office of Electric Transmission and Distribution developing? Do technologies to increase reliability exist and are they ready to be deployed today?
- What is the state of R&D funding for our electrical systems? Where should federal R&D funding be focused to ensure maximum benefit and future flexibility?
- What are the current and future barriers to the commercial application of emerging technologies? What steps have been taken to address these obstacles?

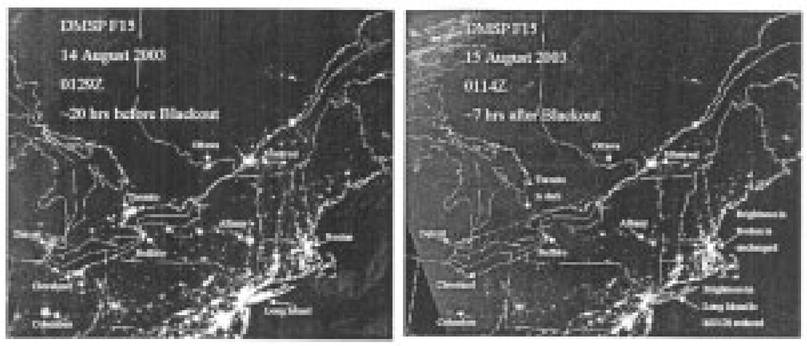

Figure 1. View from Space before and during August Blackout.

4. Brief Overview

- On August 14, 2003, a major power outage occurred across the northeastern and upper mid-western part of the United States and portions of Canada, affecting nearly 50 million customers.
- A joint U.S.-Canada task force has been established to determine the causes of the blackout.
- A contributing factor of the recent blackout—and others—was the deregulation of the utility industry, where companies no longer own their own transmission lines. As a result, investment in the infrastructure has remained flat, despite increases in electricity.
- Several solutions, including demand response, advanced transmission monitoring, communications and controls, advanced conductors, and distributed generation, have been proposed, but barriers remain. New technologies are not widely used, great variability in rules, regulations and technical specifications exist at the local level, and the cost to upgrade systems is high.
- Earlier this year (prior to the August blackout), the Administration established a new Office of Electric Transmission and Distribution at the Department of Energy in order to better address electric reliability concerns.

5. Background

On Thursday, August 14, a little after four o'clock in the afternoon, the power went out for 50 million Americans. While the precise sequence of events is not yet known, overloading of a portion of the Nation's transmission system clearly played an important role that was possibly compounded by human error and unclear lines of responsibility. Although this was the largest blackout ever in the U.S., several other serious blackouts have occurred in recent years, most notably in the Northwest in 1996, but also in San Francisco, Texas, New York State and Memphis, Tennessee.

To investigate the causes of the blackout, Energy Secretary Spencer Abraham is co-chairing a U.S.-Canadian task force, and Mr. James Glotfelty, Director of DOE's Office of Electric Transmission and Distribution, is coordinating DOE's participation in the task force's activities. One contributing factor in the most recent blackout and several of the others was the changing structure of the utility industry. As a result of deregulation, companies that generate electricity often no longer own the transmission lines they use for distribution. In addition, the companies that distribute the electricity buy power from a variety of generators, meaning that transmission lines move power in more directions than was originally contemplated. Worse, uncertainty over the future of deregulation has held investment in transmission lines relatively flat as potential investors have been unsure of how they would reap a profit. As a result, few additional transmission lines have been built and few have been upgraded relative to the increase in demand.

Technology Solutions

Building new transmission lines would ease pressure on the system, but other options may be less expensive and create less controversy. Several of the options are discussed below.

1) Demand Response

The demand for electricity varies widely over the course of a day, a month, and even a season. Highest usage, or so-called "peak load," typically occurs in the afternoons on hot summer days when air conditioners are on full power. This peak load fills the transmission grid and strains the electrical system. It is therefore no surprise that blackouts often occur during these peak times of demand.

At times of peak demand, utilities bring on-line older and more inefficient electric generators for the sole purpose of generating peak power. This, combined with the fact that lines are hot from overloading electricity, results in higher costs and less efficiency. Despite these increased costs—as much as ten times more—the price to the average consumer does not change throughout the day, so the customer has no incentive to change their demand.

Fortunately, new technologies coupled with pricing systems that charge more during peak periods can lead to significant reductions in demand. With so-called "demand response technologies," a utility can send a signal to a home or business when prices are peaking, and electrical equipment in the house can be programmed to shut off specific appliances at a particular price level. For example, one program in Florida is saving consumers an average of 15 percent off their energy bills by providing time-variant pricing and demand response technologies, for a fee. In turn, this has reduced the average household demand during peak periods by about 50 percent.

2) Advanced Transmission Monitoring, Communications and Controls

Advanced transmission control systems—sometimes called "smart grid" technologies—can increase the ability of utilities to control power flows on transmission lines. This emerging technology could prevent blackouts by enabling utilities to better monitor power flows and to limit current in dangerous situations without shutting it off completely. It could also more quickly and automatically direct the flow of current away from overloaded lines. (There is mounting evidence that during the August blackout controllers had little or no idea of the extent of the grid problems.) New technologies can also help utilities better model the grid so they can make informed decisions about how to handle problems.

3) Advanced Conductors

New technologies, including advanced wires made from ceramic composites and superconductors, could enable utilities to carry more electricity on fewer wires. Although more expensive, composites now being tested can carry two to three times the power on the same diameter as regular wires. Superconducting wires, which are also just starting to be tested, must be cooled below -300°F, but they can carry far more current with only negligible losses in power. Superconducting wires are likely to be first used in generators and transformers where they can dramatically increase efficiency, and then in short, constrained segments in urban settings, where they can be placed in existing conduits to significantly increase the flow of electricity. Other technology includes devices for electricity storage. Although currently expensive, storage could help reduce peak loads by storing off-peak power for use when demand is high.

4) Distributed Generation

Distributed generation—the use of multiple, small generators close to the users of the electricity—can ease demand by providing electricity that does not have to move over the transmission system. Distributed generation technologies include fuel cells, micro-turbines, reciprocating and Stirling engines, photovoltaics (solar energy), wind turbines, and a variety of other technologies. Distributed generation also offers security benefits, especially reduced vulnerability to catastrophic damage, whether from natural or man-made disasters.

Barriers

Despite a large federal investment—DOE has funded more than $1.2 billion in research and development since 1980 for electricity transmission and distribution research, and at least as much for various distributed generation technologies—these technologies are not in widespread use. Significant regulatory barriers, particularly in the areas of interconnection standards and market structure, impede the adoption of new technology. Interconnection standards—rules, regulations, and technical specifications that determine how electrical devices connect with local distribution grids—vary widely among different localities. The lack of uniform national standards and the existence of sometimes arcane local rules and regulations often make it prohibitively expensive to connect a distributed generation power unit to a distribution grid. A national consensus interconnection standard would reduce the cost of hardware, and significantly reduce the need for installation inspections and onsite certifications. Market structures currently in place also vary significantly by region, but very few of them are designed to convey accurate price signals to consumers indicating the true costs of electricity usage at times of peak demand.

As is often the case, the cost of installing upgraded technology can be a barrier. Some have estimated that transmission grid modernization could cost $50 billion or more over the next ten years. This translates to about one- or two-tenths of a cent per kilowatt-hour (a dollar or two per month for the average customer). But the costs of an unreliable electric system are even higher, with costs from the August blackout alone estimated to be between $4 and $6 billion. As many local victims of hurricane Isabel's wrath will attest, extended blackouts can result in spoiled food, lost work and other economic costs.

Office of Electric Transmission and Distribution

Secretary Abraham created the DOE Office of Electric Transmission and Distribution (OETD) earlier this year to address two primary functions: research and development (R&D) on electricity transmission and distribution technologies, and systems operation research and policy analysis related to the electric system. The programs run by the Office are not new; they come from various parts of DOE, primarily from the Office of Energy Efficiency and Renewable Energy (EERE).

The Department created the new office in response to recommendations from a series of reports. *The National Energy Policy,* released in 2001, which directed the Secretary to "examine the benefits of establishing a national grid, identify transmission bottlenecks, and identify measures to remove transmission bottlenecks." The Department then commissioned *The National Transmission Grid Study,* which was released in May 2002, which warned of the increasing likelihood of significant blackouts. The Grid Study provided several recommendations to improve the operation of the system, including the elimination of transmission bottlenecks and the creation of a new electricity office within DOE. Private sector groups such as the Electric Power Research Institute (EPRI) have also recommended a significant investment in the power system. Its recent study, *The Electricity Framework for the Future,* recommend increased federal investment in advanced electrical generation, transmission and distribution technologies such as those discussed earlier in this charter.

OETD's fiscal year 2003 R&D budget of $80 million includes research on high temperature superconductivity technologies, transmission systems, distribution and electricity storage technologies conducted through contracts and cost-shared agreements with universities, national laboratories, and industry. The operations and analysis subprogram includes policy modeling, analysis and technical assistance.

6. Questions for the Witnesses:

The witnesses were asked to address the following questions in their testimony before the Subcommittee:

Questions for Mr. Glotfelty

- Briefly describe the responsibilities and reporting structure of the Office of Transmission and Distribution.
- Briefly describe and rank the key vulnerabilities of the electrical grid as it is built and managed today. Are there technological solutions that could contribute to the reduction of these key vulnerabilities?
- What barriers currently prevent wider adoption of these commercially available technologies? What policy choices would be most conducive to greater adoption of these technologies?
- What was DOE's decision process in identifying the technologies it is supporting/has supported through the Office of Electricity and Distribution?

Questions for Mr. Glauthier

- What technologies are commercially available or under development to improve the efficiency and reliability of our electrical system? Which technologies would you suggest receive the highest priority for targeted DOE research and development funding?
- What barriers currently prevent wider adoption of these commercially available technologies? What policy choices would be most conducive to greater adoption of these technologies?
- What is the current level of investment by the private sector in improvements to the grid that enhance its reliability? How can the private sector and the Federal Government best share responsibility for ensuring the reliability of the Nation's electrical grid?
- What level of federal funding would be necessary and appropriate for research, development, demonstration and deployment of smart grid technology? What should the private share be?

Questions for Dr. Smith

- Briefly describe the market structure for the electricity sector as it existed 15 years ago and contrast it with the structure today.
- What barriers currently prevent wider adoption of commercially available energy technologies? What policy choices would be most conducive to greater adoption of these technologies?
- How is uncertainty affecting the economics of investment in the electricity sector? How can we structure a market to ensure reliable electricity at the lowest cost?
- What are the incentives for utilities to invest in transmission research and development? How can we encourage investment in research and development in a highly competitive electricity sector?

Questions for Mr. Casten

- Please give a brief description of your current business ventures designed to capture waste heat.
- How can distributed generation improve the reliability of the overall electrical system? What other benefits does distributed generation provide?
- What barriers currently prevent wider adoption of commercially available energy technologies? What policy choices would be most conducive to greater adoption of these technologies?
- Do some states or regions of the country do a better job at encouraging the dissemination of distributed generation technologies? What specifically makes them different?

Chairwoman BIGGERT. The hearing will come to order.

I want to welcome everyone to this hearing of the Energy Subcommittee. Our purpose here is to identify current and emerging technologies and the barriers to their deployment that will help improve the reliability of our nation's increasingly complex electrical system.

The blackout that occurred on August 14 leaving 50 million Americans without power was a startling reminder of the vulnerability of our current antiquated system and the enormous costs associated with such an unreliable system. Many communities in my District, thankful that the blackout stopped short of Chicago, watched and learned that the blackout meant so much more than no electricity. They came to realize that a blackout could mean no public transportation, no stoplights, no security lights, no heat or air conditioning, and in some cases, no water.

While a national joint task force is still investigating the exact causes of the August 14 blackout, it is clear that overloading of a portion of the Nation's transmission system played an important role. But regardless of what the exact cause of the blackout was, the bottom line is this: we simply can not meet today's energy needs with yesterday's energy infrastructure. No pun intended, but we are virtually in the dark ages when it comes to energy infrastructure. This is especially true with respect to the electric grid.

But the answer isn't necessarily more lines or even necessarily new and better ones. We must consider other, better ways to obviate the need for more lines, such as greater use of distributed generation and reducing peak demand for electricity through technologies that improve efficiency, communications, and controls. And we must make better use of whatever lines we do have, which is where advanced technology could have the greatest impact. Improved monitors of controls could prevent and isolate transmission failures and other new technologies promised to enable the transmission system to sustain far greater loads.

Americans want affordable and reliable energy, and yet, because we have ignored technology, we act as though the two are mutually exclusive. The only way to have both at the same time is first to take our head out of the sand and second by putting technology to work and cutting some of the 1930's style government red tape that has stifled the development of new technology and infrastructure.

Our witnesses today will discuss currently available emerging technologies and the regulatory and economic barriers that impede their adoption. Their testimony also will provide an opportunity to learn more about the Department of Energy's newly formed Office of Electric Transmission and Distribution and its work on these issues.

As Congress works to eliminate barriers that discourage investment in new grid technologies and distributed generation, and consequently, as the competitive market begins to function properly, this committee and this subcommittee, in particular, must do two things: first we must ensure that whatever regulations remain do not limit or impede technological solutions; and secondly, we must ensure that the best and most promising technology is ready and available for deployment. I hope our witnesses today can help shed some light on how we can be successful on both fronts.

As the recent blackout demonstrated, the cost of continued inaction far exceeds the cost of action. Some estimate that the cost—total cost of upgrading our electrical grid will be $50 billion or more over the next 10 years, but the cost of an unreliable electric system are even higher with costs of the August 14 blackout alone estimated to be between $4 billion and $6 billion. By investing in new technologies to improve our electrical system, we are investing in an infrastructure that supports virtually every component of our economy. That is why a robust, resilient, and reliable electrical system is unquestionably in our nation's interest. We must work together to determine the best way to get there. I think we can all agree that advanced technologies can be a major part of the solution as long as the barriers to their deployment and use are removed.

I look forward to hearing today's testimony and pursuing those subjects in greater detail.

[The prepared statement of Mrs. Biggert follows:]

PREPARED STATEMENT OF CHAIRMAN JUDY BIGGERT

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I want to welcome everyone to this hearing of the Energy Subcommittee. Our purpose here is to identify current and emerging technologies—and the barriers to their deployment—that will help improve the reliability of our nation's increasingly complex electrical system.

The blackout that occurred on August 14th, leaving 50 million Americans without power, was a startling reminder of the vulnerability of our current, antiquated system, and the enormous costs associated with such an unreliable system. Many communities in my district, thankful that the blackout stopped short of Chicago, watched and learned that the blackout meant so much more than no electricity. They came to realize that a blackout could mean no public transportation, no stoplights, no security lights, no heat or air conditioning, and in some cases, no water.

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I look forward to listening to today's testimony and pursuing these subjects in greater detail.

Chairwoman BIGGERT. The Chair now recognizes the Ranking Minority Member on the Energy Subcommittee for his only—his opening statement.

Mr. LAMPSON. Thank you, Chairwoman Biggert. I want to thank you for calling this very important hearing this morning. And certainly I want to thank our witnesses for joining us here today. We appreciate having all of you.

The recent blackout suffered by 50 million Americans in the Midwest and the Northeast on August the 14th has indeed brought the issue of electricity generation and transmission into clearer focus. The blackout was the largest ever in the United States. And the cost in the United States has been estimated to be somewhere between $4 billion and $6 billion.

This incident spurred the creation of a joint United States-Canadian task force on the factors that contributed to this event. As the Administration, Congress, and the joint task force continue to examine the factors behind the incident, I believe that it's imperative that we consider the role technology can play in preventing future blackouts. We need to ensure that our power transmission services are reliable and secure while we continue to prevent future disruptions across the country. Technological advances will play a very key role in this endeavor.

While I understand that many have called for the construction of new transmission lines, I look forward to hearing from our witnesses about how smart grid and demand response technologies might also help utility companies handle these problems in the future. Advanced conductors made from ceramic composites and superconducting wires could also dramatically increase efficiency. And I am also interested to hear about the role that reactive power may have played in this incident and whether we have technological advances to help us understand this phenomenon.

My congressional district has the distinction of being serviced by two electricity grids. My Houston-Galveston area constituents are served by Electric Reliability Council of Texas, ERCOT, while my Beaumont, Port Arthur, and Chambers County constituents are under the Southeastern Electric Reliability Council, SERC. I have reached out to the utility companies in my area for their thoughts and their ideas on how we can improve the electricity grids. And while it was the Midwest and Northeast on August the 14th, other parts of the country have experienced blackouts in recent years, and I am sure that other regions will also experience them in the future.

So I am committed to working with our power companies, federal, State, and local officials to utilize available technologies and to ensure that we minimize future disruptions. As a nation, we must be proactive about these problems rather than reactive as we respond to these challenges, and I look forward to hearing from our witnesses.

Thank you, Madame Chairman.

[The prepared statement of Mr. Lampson follows:]

PREPARED STATEMENT OF REPRESENTATIVE NICK LAMPSON

I would like to thank Chairwoman Biggert for calling this very important hearing. And I would also like to thank all of our witnesses for joining us here today.

The recent blackout suffered by 50 million Americans in the Midwest and Northeast on August 14th has brought the issue of electricity generation and transmission into a clear focus.

The blackout was the largest ever in the United States and the cost to the U.S. has been estimated at between $4 and $6 billion.

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I am committed to working with power companies, federal, State and local officials to utilize available technologies and ensure that we minimize future disruptions.

As a nation we must be proactive about these problems rather than reactive as we respond to these challenges.

Chairwoman BIGGERT. Thank you. I would like to ask at this time for a unanimous consent that all Members who wish to do so have their opening statements entered into the record. Without objection, so ordered.

[The prepared statement of Mr. Costello follows:]

PREPARED STATEMENT OF REPRESENTATIVE JERRY F. COSTELLO

Good morning. I want to thank our witnesses for appearing before this committee to discuss removing barriers to technology to prevent blackouts. On August 14 and 15, 2003, the northeastern U.S. and southern Canada suffered the worst power blackout in history. Areas affected extended from New York, Massachusetts, and New Jersey west to Michigan, and from Ohio north to Toronto and Ottawa, Ontario. Approximately 50 million customers were impacted, and the economic costs will be staggering.

Getting to the bottom of things will not be easy, given the complexity of the electrical system, but will require answers to three simple questions. What exactly happened? Why did it happen? And how can it be prevented in the future? In answering the last question, continued research and development in our electric system will help us improve our grid system and hopefully prevent another blackout from occurring.

If future blackouts are to be avoided, we must fix these problems quickly and decisively and continue to promote research and development that will address the reliability and security of the electric energy transmission system. Southern Illinois University (SIU) in my congressional district has been continuously working on research on a variety of electric transmission issues. SIU was among the first to receive research contracts from the Electric Power Research Institute (EPRI) in launching the Flexible AC Transmission Initiative. In addition, SIU has received grants from the National Science Foundation, the Department of Energy and Electric Utilities for electric transmission research. Further, the university is currently working on Broad Band over Power Lines which is an emerging technology utilizing the backbone of the power distribution network for the transmission of high-speed data.

SIU is one example of promising work in improving our electric system; however, more is needed. EPRI estimates that research and demonstration programs will require increased federal funding of approximately $1 billion, spread out over five years, with the private sector contributing a significant amount of matching funding. I am interested in hearing from our witnesses about a public/private institutional role for research and development.

I welcome our panel of witnesses and look forward to their testimony.

Chairwoman BIGGERT. It is my pleasure to welcome our witnesses for today's hearing and to introduce them to you. They are: Mr. James Glotfelty, Director of the Office of Electric Transmission and Distribution, U.S. Department of Energy; Mr. T.J. Glauthier, President and CEO, Electricity Innovation Institute; Dr. Vernon Smith, Nobel Laureate and Professor of Economics, George Mason University; and Mr. Tom Casten, CEO, Private Power, LLC. I would like to extend a special welcome to Mr. Casten, a constituent of my District and to congratulate him on his impressive work he has done for more than 25 years in developing and operating combined heat and power plants as a way to save money, increase efficiency, and lower emissions. Welcome to all of you.

As the witnesses know, spoken testimony will be limited to five minutes each, after which Members will have five minutes each to ask questions. So we will begin with Mr. Glotfelty.

STATEMENT OF MR. JAMES W. GLOTFELTY, DIRECTOR, OFFICE OF ELECTRIC TRANSMISSION AND DISTRIBUTION, U.S. DOE

Mr. GLOTFELTY. Thank you very much.

Good morning, Chairman Biggert and Members of the Subcommittee. My name is Jimmy Glotfelty. I'm the Director of the newly created Office of Electric Transmission and Distribution at the Department of Energy. Thank you for the opportunity to testify before you today on the role that technology can play in the development of a more robust and reliable electric system.

America's electric system is facing serious problems: aging equipment, uncertain regulations at both the federal and State level, and difficulty attracting investment capital, all in the face of rising demand. As you may know, the National Academy of Sciences called America's electric system "the supreme engineering achievement of the 20th century." However, as currently configured, there are serious questions about the ability of this system to satisfy the complex needs necessary to power the economy in the 21st century.

The U.S. Department of Energy is leading an effort to help facilitate the modernization of our nation's aging electric grid. DOE, in collaboration with industry and other partners, developed Grid 2030, a national vision for tomorrow's electric system, and a road map that outlines the key challenges for modernizing the grid and suggested paths and—suggested paths to get there. The vision and road map called for government and industry to work today in a collaborative manner. They implement a five-part action agenda to modernize the grid and achieve the Grid 2030 vision. This agenda includes: study the feasibility of a national transmission backbone; continue the development of critical technologies that make the future grid more stable, more efficient, and more reliable; accelerate technology acceptance; strengthen market operations and allow the marketplace to promote new technologies that strengthen our grid; and finally, build multi-year public/private partnerships with industry, states, reliability councils to ensure that this vision becomes a reality.

Transmission, distribution, researching efforts at DOE have been in existence for many years. Many commercialized technologies that enhanced the reliability of the electric grid today began with DOE research many years ago. However, there are many more technologies that require further research, development, and demonstration to ensure their effective performance in the field. This is critical to acceptance in the marketplace. For example, DOE is working with industry to test high-capacity transmission lines made of new materials that will carry more electrical current, reduce losses, and are lighter weight and lower in cost. Testing these lines at our Oak Ridge National Lab Transmission Testing Center will help industry reduce barriers that lead to commercial viability of these products. New communication and control technologies are necessary to promote an electricity grid with embedded intelligence that will process vast amounts of information in less than a second and help operators make more accurate reliability and economic decisions.

Advances in power electronics today already allow more power to flow through existing systems. Improvements will better control the flow of AC power flows and allow operators to isolate problems that could cause larger regional disruptions. In the future, high-temperature superconductors have the potential to revolutionize electric power delivery in America. The prospect of transmitting large amounts of power through compact underground corridors over long distances with minimal losses could significantly enhance the overall efficiency and reliability of the electric system, all while reducing fuel use and emissions. Superconducting technologies will be used in generators, cables, transformers, storage devices, and motors: equipment that crosscuts the entire electric power center.

While these technologies are still being developed, there are still major stumbling blocks in their widespread deployment on the grid. The primary reason is uncertainty: regulatory uncertainty and financial uncertainty. The lack of investment in grid modernization has been caused by uncertainty in electric utility regulations at the federal and State level. The jurisdictional boundaries are not clear, and the difficult transition from a tightly regulated industry to one where competition and market forces play a greater role has taken years too long. Regulatory uncertainty has lasted almost a decade, and its consequences are beginning to be felt across the Nation.

Investment uncertainty is directly tied to the state of regulation. If markets see clear signals as to a return on investment, they will invest. If not, the capital will flow to a more stable industry. During this time of uncertainty, both investment in the transmission system and R&D funding by the industry has declined. In fact, transmission reliability research at the Department of Energy was zeroed out for three years in the 1990's: '96, '97, and '98. These private/public cutbacks have slowed the push for new technologies and tools into the marketplace.

While this regulatory rethinking proceeds, several states have implemented price caps as a way to protect consumers from price shocks while the markets adjust to make policy—allow policy-makers to identify next steps. While attractive to the regulator, price caps could very well hinder investment, because they raise the uncertainty of cost recovery for new equipment.

As you know, there are many things that must be done to bring our electrical infrastructure up to a 21st century standard. August—the August 14 blackout is an example of what could happen again in the future if we do not begin to focus on the improvement of our grid today. The U.S. economy's reliance on a secure, reliable infrastructure has never been greater. Modernizing the grid will involve time, resources, and unprecedented levels of cooperation among electric power industries, many and diverse stakeholders. Neither government nor industry can shoulder these responsibilities alone. We must act now or risk greater problems in the future.

I thank you for the opportunity to testify before you today and look forward to addressing your questions.

[The prepared statement of Mr. Glotfelty follows:]

PREPARED STATEMENT OF JAMES W. GLOTFELTY

Introduction

Chairman Biggert and Members of the Subcommittee, thank you for the opportunity to testify today on the role of new technologies in developing a more robust electric system.

America's electric system is facing serious problems: aging equipment and infrastructure, uncertain regulations and policies, difficulties attracting investment capital, and constrained supplies failing to meet rising demand. The National Academy of Sciences called America's electric system ". . .the supreme engineering achievement of the 20th century." However, as currently configured, there are serious questions about the ability of this system to satisfy the increasingly complex electricity needs of the 21st century.

The President is well aware of this problem. For example, on February 6th 2003, President Bush reiterated the Administration's policy to modernize the electric grid, "It is a plan to modernize our electricity delivery system. It is a plan which is needed now. It is needed for economic security. It is needed for national security." The August blackout highlighted the economy's reliance on a secure and reliable electric system. Billions of dollars in goods and services, in productivity and food, were lost.

Implementing the President's plans for modernizing America's electricity infrastructure is one of the U.S. Department of Energy's top priorities. The President's *National Energy Policy* directed preparation of a detailed assessment of the major bottlenecks in our nation's transmission system, and in May 2002, Secretary Abraham issued *The National Transmission Grid Study*. This report made clear that without dramatic improvements and upgrades over the next decade our nation's transmission system will fall short of the reliability standards our economy requires, and will result in higher costs to consumers. The Department immediately began taking steps to implement the improvements that are needed to ensure continued growth and prosperity, working with Congress, States, and other stakeholders to promote innovation and enable entrepreneurs to develop a more advanced and robust transmission system. The mission of DOE's newly created Office of Electric Transmission and Distribution is focused on achieving this end.

Opportunities for Modernizing America's Electric System

Modernization includes the application of new and existing technologies to enhance the reliability and efficiency of the entire electric system. Electric reliability and efficiency are affected by all four segments of the electricity value chain: generation, transmission, distribution, and end-use. Investing in only one area will not necessarily stimulate performance improvements across other segments of the integrated system. Increasing supply without improving transmission and distribution infrastructure, for example, may actually lead to more serious reliability concerns. Thus, to improve the reliability and efficiency of electric power in America—as called for in the President's energy plan—equipment upgrades as well as new technologies are needed throughout the electric system.

With electric generation, reliability is enhanced when additional supplies are added to ensure that peak demands are met. Reliability is also enhanced when sufficient reserve capacity is available for scheduled and unscheduled maintenance, and for emergency situations. Additional supplies can come from expansion of both central and distributed assets, representing a variety of technologies and fuel choices. Efficiency is enhanced when more fuel-efficient generation technologies are used, such as combined cycle combustion turbines and combined heat and power units. However, expanding supplies without balancing investment in transmission and distribution infrastructure will place additional cost burdens on consumers, both in terms of congestion and reliability. A reliable system requires balanced investment in supply, delivery, and demand management.

With respect to electric transmission, reliability is enhanced when additional lines are added to the grid, proper maintenance occurs in a timely manner, and when grid operators are able to make adjustments, in real-time, to address fluctuations in system conditions, particularly during periods of peak demand. Efficiency is enhanced when new transmission technologies are used that have reduced line losses, and that have the capability to carry more current for a given size of conductor. The Department is partnering today with industry to develop cost-effective transmission solutions, including advanced composite conductors, high temperature superconductors, and wide area measurement systems.

With respect to electric distribution, reliability is enhanced when additional lines are added, substation capabilities are expanded, proper maintenance occurs in a timely manner, communications and interconnections systems facilitate distributed energy development, and systems are protected better from natural disturbances. Efficiency is enhanced when new distribution technologies are deployed that reduce line losses, and information technologies optimize existing resources. The Department is working with States and industry to develop transformers, fault current limiters, cables, and power electronics that will revolutionize the distribution system.

With respect to electric end-use, reliability is enhanced when demand response programs manage electricity consumption in ways that result in lower overall peak demand and a better balance between on- and off-peak usages. Actions can include use of such technologies as real-time (or time-of-use) meters, and advanced energy storage. Efficiency is enhanced when new appliances and equipment require less electricity to produce equal (or greater) levels of service, such as advanced lighting, heating, cooling, refrigeration, and motor drive devices. Although peak load management offers significant benefits to utilities, electric consumption is controlled by the end-users. Their participation in a fully integrated energy system requires price transparency.

Barriers to Electric Grid Modernization

For more than two decades, America has been under-investing in the modernization of the electric system. The primary reason is uncertainty: technical uncertainty; regulatory uncertainty; and financial uncertainty. The consequences of this have been significant: greater numbers of congested transmission corridors, a higher likelihood of brownouts and blackouts, and more economic losses from outages when they do occur. Annual estimates of losses from outages and power quality disturbances range from $25 to $180 billion annually. Standard and Poor's estimates the economic losses from the August 14th blackout to be about $6 billion. Although some estimate it will take $100 billion to modernize the electric system, this should be compared against the scale of the existing electric industry: infrastructure worth approximately $800 billion (including generation), and revenues approaching $250 billion annually.

There are electricity technologies that are ready today to be used for grid modernization projects. However, electric assets are capital-intensive and long-lived, so the stock turnover process is relatively slow. Much of the Nation's electric infrastructure of power lines, substations, switchyards, and transformers has been in service for 25 years, or longer.

The primary reason for the lack of investment in grid modernization is the financial uncertainty caused by the uneven process of restructuring of electric utility regulation, at both the federal and state levels. The electric power business currently is in and has for the last few years been in the midst of a difficult transition from a tightly regulated industry to one where competition and market forces play a greater role.

This transition has been slow and there have been missteps. For example, the unfortunate experience in California cost citizens billions of dollars, and has caused other states to re-think their approach to electric power regulation.

Regulatory uncertainty has affected other aspects of grid modernization. For example, there seems to have been a substantial decline in the level of spending recently by the electric power industry in research and development. The Electric Power Research Institute reports that its R&D funding from member utilities has fallen from about $600 million annually in 1994 to about $300 million annually in 2001. Federal spending on electric system research and development during that same time period did not rise to fill the gap. For example, for fiscal years 1996, 1997, and 1998, the funding for DOE's Transmission Reliability research and development program was zeroed out. This significant reduction in R&D investments has limited the flow of new technologies, tools, and techniques into the marketplace.

There are other barriers to the acceptance of new electric delivery technologies in the marketplace. Equipment must be introduced into the electric system in a manner that will ensure safe, reliable, and efficient operation. The electric industry is reluctant to use new technologies unless their functionality, and especially durability, is ensured. This slows down the process of moving technologies from the laboratory and into the "tool-kit" of electric system planners and operators. Some of the difficulties stem from problems in managing the risks associated with using new technologies, risks common to all industries. These technology transfer difficulties are exacerbated in the electric power sector by a regulatory framework that favors the status quo and does not typically reward managers for innovation, risk taking, or entrepreneurial activities. There is a need to work with State commissions to familiarize them with the new technologies and the extent to which their reliability has been demonstrated.

While this "re-thinking" proceeds, several states have implemented "price caps" as a way to protect consumers from price shocks while the markets adjust and policy makers identify next steps. While attractive to the regulator, price caps tend to hinder investment because they raise the uncertainty of cost recovery for new plant and equipment. For example, utilities subject to price caps cannot seek rate increases to recover reliability investment costs; they have to identify offsets from other aspects of their operation to maintain profitability.

Finally, public concern about the environmental, public health, and safety consequences of electric power has resulted in local or state siting and permitting processes that in many cases have impacted additional capacity. There are numerous instances over the past decade where projects to modernize the electric grid were stymied by siting and permitting delays caused by bureaucratic requirements or jurisdictional disputes among states and the Federal Government. This has greatly hindered new investment despite the existence of a guaranteed rate of return for investors. However, technologies such as advanced composite conductors that utilize existing transmission facilities may have a potential advantage over technologies that would require new rights-of-way.

Administration Action to Address Barriers

The Bush Administration, from the outset, has highlighted the importance of modernizing America's electric system. It is one of the most important policy objectives discussed in the President's *National Energy Policy,* which was issued in May 2001. One year later, the Department issued *The National Transmission Grid Study,* which contains 51 specific recommendations for modernizing the grid and increasing the reliability of America's transmission system. In September 2002, the Secretary's Energy Advisory Board issued the *Transmission Grid Solution Report* which outlines steps to streamline transmission siting and permitting and increase the level of investment in electric transmission facilities. In April 2003, the President's Council of Advisors on Science and Technology issued a report calling for expanded federal investment in electric grid modernization technologies.

Also in April 2003, the Department held the National Electric System Vision meeting, which resulted in *Grid 2030—a National Vision for Electricity's Second 100 Years,* a document that presents industry and DOE's views on the future of electric power in America. In July 2003, the Department followed up the "Grid 2030" vision with the National Electric Delivery Technologies Roadmap meeting, which will soon result in a document outlining the research, development, and technology transfer steps that government, industry, and others need to take to make the national vision for the future of the electric system into reality. The U.S. Department of Energy's website, *www.energy.gov,* provides access for downloading copies of these documents and reports.

"Grid 2030"—A National Vision for Electricity's Second 100 Years

The national vision calls for "Grid 2030" to energize a competitive North American marketplace for electricity. It will connect everyone to abundant, affordable, clean, efficient, and reliable electric power anytime, anywhere. It will provide the best and most secure electric services available in the world. Imagine the possibilities: electricity and information flowing together in real time, near-zero economic losses from outages and power quality disturbances, a wider array of customized energy choices, suppliers competing in open markets to provide the world's best electric services, and all of this supported by a new energy infrastructure built on superconductivity, distributed intelligence and resources, clean power, and the hydrogen economy.

Although the precise architecture of America's future electric system has yet to be designed, the "Grid 2030" concept has been envisioned to consist of three major elements:

- A national electricity "backbone"
- Regional interconnections which include Canada and Mexico
- Local distribution, mini- and micro-grids providing services to customers from generation resources anywhere on the continent.

The backbone system will involve a variety of technologies. These include controllable, very-low-impedance superconducting cables and modular transformers operating within the synchronous AC environment; high voltage direct current devices forming connections between regions; and other types of advanced electricity conductors, as well as information, communications, and controls technologies for supporting real-time operations and national electricity transactions. Superconducting systems will be able to reduce line losses, assure stable voltage, and expand current carrying capacities in dense urbanized areas. They will be seamlessly integrated with high voltage direct current systems and other advanced conductors for transporting electric power over long distances.

Power from the backbone system will be distributed over regional networks. Long-distance transmission within these regions will be accomplished using upgraded, controllable AC facilities and, in some cases, expanded DC links. High-capacity DC inter-ties will be employed far more extensively than they are today to link adjacent, asynchronous regions. Regional system planning and operations will benefit from real-time information on the status of power generation facilities (central-station and distributed) and loads. Expanded use of advanced electricity storage devices will address supply-demand imbalances caused by weather conditions and other factors. In this grid of the future, markets for bulk power exchanges will be able to operate more efficiently with oversight provided through mandatory reliability standards, multi-state entities, and voluntary industry entities.

In the "Grid 2030" distribution system, it is envisioned that customers will have the ability to tailor electricity supplies to suit their individual needs for power, including costs, environmental impacts, and levels of reliability and power quality. Sensors and control systems will be able to link appliances and equipment from inside buildings and factories to the electricity distribution system. Advances in distributed power generation systems and hydrogen energy technologies could enable the dual use of transportation vehicles for stationary power generation. For example, hydrogen fuel cell powered vehicles could be able to provide electricity to the local distribution system when in the garage at home or parking lot at work.

National Electric Delivery Technologies Roadmap

The Roadmap, which is still being finalized by DOE, will call for the collaborative implementation by government and industry of a five-part "action agenda" to modernize the grid and achieve the "Grid 2030" vision. The action agenda includes:

- Designing the "Grid 2030" Architecture—Conceptual framework that guides development of the electric system from the generation busbar to the customer's meter
- Developing the Critical Technologies—Advanced conductors, electric storage, high-temperature superconductors, distributed intelligence/smart controls, and power electronics that become the building blocks for the "Grid 2030" concept
- Accelerating Technology Acceptance—Field testing and demonstrations that move the advanced technologies from the laboratory and into the "tool kit" of transmission and distribution system planners and operators
- Strengthening Market Operations—Assessing markets, planning, and operations; improving siting and permitting; and addressing regulatory barriers bring greater certainty and lower financial risks to electric transactions and investment
- Building Partnerships—Leveraging stakeholder involvement through multi-year, public-private partnerships; working with States, FERC, and NERC to address shared concerns

Technologies for Modernizing the Electric Grid

There is a portfolio of technologies that have the capabilities to enhance the reliability and efficiency of the electric grid. Many of these will require further research, development, field testing, and demonstration to lower costs, improve reliability and durability, and demonstrate effective performance. The Appendix, taken from the National Transmission Grid Study, provides additional details on a wide range of grid modernization technologies.

Advanced Conductors and New Materials. Desirable properties of new material for electricity conductors include greater current-carrying capacity, lower electrical resistance, lighter weight, greater durability, greater controllability, and lower cost. Advances in semiconductor-based power electronics have given rise to new solutions that allow more power flow through existing assets, while respecting local land use concerns. Advanced composite materials and alloys are also making an impact and are being used in new designs for conductors and cables. Diamond technology could replace silicon and achieve dramatic increases in current density. In addition, scientific discoveries in advanced materials are resulting in new concepts for conductors of electric power. For example, nanoscience is opening new frontiers in the design and manufacture of machines at the molecular level for fabricating new classes of metals, ceramics, and organic compounds (such as carbon nanotubes) that have potential electric power applications.

High Temperature Superconductors. High temperature superconductors are a good example of advanced materials that have the potential to revolutionize electric power delivery in America. The prospect of transmitting large amounts of power through compact underground corridors, even over long distances, with minimal electrical losses and voltage drop, could significantly enhance the overall energy efficiency and reliability of the electric system, while reducing fuel use, air emissions, and physical footprint. Superconducting technologies can be used in generators, cables, transformers, storage devices, synchronous condensers, and motors—equipment that crosscuts the entire electric power value chain.

Electricity Storage. Breakthroughs that dramatically reduce the costs of electricity storage systems could drive revolutionary changes in the design and operation of the electric power system. Peak load problems could be reduced, electrical stability could be improved, and power quality disturbances could be eliminated. Storage can be applied at the power plant, in support of the transmission system, at various points in the distribution system, and on particular appliances and equipment on the customer's side of the meter.

Communications, Controls and Information Technologies. Information technologies (IT) have already revolutionized telecommunications, banking, and certain manufacturing industries. Similarly, the electric power system represents an enormous market for the application of IT to automate various functions such as meter reading, billing, transmission and distribution operations, outage restoration, pricing, and status reporting. The ability to monitor real-time operations and implement automated control algorithms in response to changing system conditions is just beginning to be used in electricity. Visualization tools are just beginning to be used by electric grid operators to process real-time information and accelerate response times to problems in system voltage and frequency levels. Distributed intelligence, including "smart" appliances, could drive the co-development of the future architecture for both telecommunications and electric power networks, and determines how these systems are operated and controlled. Data access and data management will become increasingly important business functions.

Advanced Power Electronics. High-voltage power electronics allow precise and rapid switching of electrical power. Power electronics are at the heart of the interface between energy storage and the electrical grid. This power conversion interface—necessary to integrate direct current or asynchronous sources with the alternating current grid—is a significant cost component of energy storage systems. Additionally, power electronics are the key technology for power flow controllers (e.g., Flexible Alternating Current Transmission Systems—FACTS) that improve power system control, and help increase power transfer levels. New power electronics advances are needed to lower the costs of these systems, and accelerate their application on the network.

Distributed Energy Technologies. Developments to improve the performance and economics of distributed energy generation and combined heat and power systems could expand the number of installations by industrial, commercial, residential, and community users of electricity. Devices such as fuel cells, reciprocating engines, distributed gas turbines and micro-turbines can be installed by users to increase their power quality and reliability, and to control their energy costs. They can lead to reduced "upstream" needs for electric generation, transmission, and distribution equipment by reducing peak demand.

Potential Benefits of Grid Modernization

An expanded and modernized grid will virtually eliminate electric system constraints as an impediment to economic growth and in fact will promote and encourage economic growth. As stated in *The National Transmission Grid Study,* wholesale markets save consumers $13 billion annually, but constraints cost billions more. Robust national markets for electric power will encourage growth and open avenues for attracting capital to support infrastructure development and investment in new plant and equipment. New business models will emerge for both small and large companies for the provision of a wide variety of new products and services for electricity customers, distributors, transmitters, and generators.

More energy efficient transmission and distribution will reduce line losses and help avoid emission of air pollution and greenhouse gases. More economically efficient system operations and the expanded use of demand-side management techniques will reduce the need for spinning reserves, which could also lower environmental impacts. A modernized national electric grid will facilitate the delivery of electricity from renewable technologies such as wind, hydro, and geothermal that have to be located where the resources are located, which is often remote from load centers.

Faster detection of outages, automatic responses to them, and rapid restoration systems will improve the security of the grid, and make the grid less vulnerable to physical attacks from terrorists. Greater integration of information and electric technologies will involve strengthened cyber security protections. Expanded use of distributed energy resources will provide reliable power to military facilities, police stations, hospitals, and emergency response centers. This will help ensure that "first-responders" have the ability to continue operations even during worst-case conditions. Greater use of distributed generation will lessen the percentage of generated power that must flow through transmission and distribution systems, reducing strain on the grid. Higher levels of interconnection with Canada, Mexico, and ultimately other trading partners will strengthen America's ties with these nations and boost security through greater economic cooperation and interdependence.

Conclusion

The electric grid is an essential part of American life. America has under-invested in maintenance of the national electric grid and in the development and deployment of advanced electric delivery technologies. Most of today's existing infrastructure of wires, transformers, substations, and switchyards has been in use for 25 years, or more. The aging of this infrastructure, and the increasing requirements placed on it, have contributed to market inefficiencies and electricity congestion in several regions. These conditions could lead to higher prices, more outages, more power quality disturbances, and the less efficient use of resources. Jobs, environmental protection, public health and safety, and national security are at risk. We must act now or risk even greater problems in the future.

In recognition of this, President Bush has asked the U.S. Department of Energy to lead a national effort to modernize the electric grid. The newly formed Office of Electric Transmission and Distribution has been given the assignment to do just that. The Office will work in partnership with the electric industry, states, and other stakeholders to develop a national vision of the future for America's electric grid, and a national roadmap of collaborative activities to achieve the vision. The Office's activities will include research and development, technology transfer, modeling and data analysis, and policy analysis.

Modernizing the grid will involve time, resources, and unprecedented levels of cooperation among the electric power industry's many and diverse stakeholders. Neither government nor industry can shoulder these responsibilities alone. The Office of Electric Transmission and Distribution stands ready to lead this transformation.

Appendix

List of Technology Options for Grid Modernization

This appendix, taken from *The National Transmission Grid Study,* contains a list of some of the technologies that are being researched and deployed to modernize the electric grid. The range of potential technologies is enormous and the list presented is not exhaustive.

- *Advanced Composite Conductors:* Usually, transmission lines contain steel-core cables that support strands of aluminum wires, which are the primary conductors of electricity. New cores developed from composite materials are proposed to replace the steel core.

  Objective: Allow more power through new or existing transmission rights of way.

  Benefits: A new core consisting of composite fiber materials shows promise as stronger than steel-core aluminum conductors while 50 percent lighter in weight with up to 2.5 times less sag. The reduced weight and higher strength equate to greater current carrying capability as more current-carrying aluminum can be added to the line. This fact along with manufacturing advances, such as trapezoidal shaping of the aluminum strands, can reduce resistance by 10 percent, enable more compact designs with up to 50 percent reduction in magnetic fields, and reduce ice buildup compared to standard wire conductors. This technology can be integrated in the field by most existing reconductoring equipment.

  Barriers: More experience is needed with the new composite cores to reduce total life-cycle costs.

  Commercial Status: Research projects and test systems are in progress.

- *High-Temperature Super-Conducting (HTSC) Technology:* The conductors in HTSC devices operate at extremely low resistances. They require refrigeration (generally liquid nitrogen) to super-cool ceramic superconducting material.

  Objective: Transmit more power in existing or smaller rights of way. Used for transmission lines, transformers, reactors, capacitors, and current limiters.

  Benefits: Cable occupies less space (AC transmission lines bundle three phase together; transformers and other equipment occupy smaller footprint for same level of capacity). Cables can be buried to reduce exposure to electric and magnetic field effects and counteract visual pollution issues. Transformers can reduce or eliminate cooling oils that, if spilled, can damage the environment. The HTSC itself can have a long lifetime, sharing the properties noted for surface cables below.

  Barriers: Maintenance costs are high (refrigeration equipment is required and this demands trained technicians with new skills; the complexity of system can result in a larger number of failure scenarios than for current equipment; power surges can quench (terminate superconducting properties) equipment requiring more advanced protection schemes).

  Commercial Status: A demonstration project is under way at Detroit Edison's Frisbie substation. Four-hundred-foot cables are being installed in the substation. Self-contained devices, such as current limiters, may be added to address areas where space is at a premium and to simplify cooling.

- *Below-Surface Cables:* The state of the art in underground cables includes fluid-filled polypropylene paper laminate (PPL) and extruded dielectric polyethylene (XLPE) cables. Other approaches, such as gas-insulated transmission lines (GIL), are being researched and hold promise for future applications.

  Objective: Transmit power in areas where overhead transmission is impractical or unpopular.

  Benefits: The benefits compared with overhead transmission lines include protection of cable from weather, generally longer lifetimes, and reduced maintenance. These cables address environmental issues associated with EMFs and visual pollution associated with transmission lines.

  Barriers: Drawbacks include costs that are five to 10 times those of overhead transmission and challenges in repairing and replacing these cables when problems arise. Nonetheless, these cables represent have made great technical advances; the typical cost ratio a decade ago was 20 to one.

Commercial Status: PPL cable technology is more mature than XLPE. EHV (extra high voltage) VAC and HVDC applications exist throughout the world. XLPE is gaining quickly and has advantages: low dielectric losses, simple maintenance, no insulating fluid to affect the environment in the event of system failure, and ever-smaller insulation thicknesses. GILs feature a relatively large-diameter tubular conductor sized for the gas insulation surrounded by a solid metal sleeve. This configuration translates to lower resistive and capacitive losses, no external EMFs, good cooling properties, and reduced total life-cycle costs compared with other types of cables. This type of transmission line is installed in segments joined with orbital welders and run through tunnels. This line is less flexible than the PPL or XLPE cables and is, thus far, experimental and significantly more expensive than those two alternatives.

Underwater application of electric cable technology has a long history. Installations are numerous between mainland Europe, Scandinavia, and Great Britain. This technology is also well suited to the electricity systems linking islands and peninsulas, such as in Southeast Asia. The Neptune Project consists of a network of underwater cables proposed to link Maine and Canada Maritime generation with the rest of New England, New York, and the mid-Atlantic areas.

- *Tower Design Tools:* A set of tools is being perfected to analyze upgrades to existing transmission facilities or the installation of new facilities to increase their power-transfer capacity and reduce maintenance.

Objective: Ease of use and greater application of visualization techniques make the process more efficient and accurate when compared to traditional tools. Traditionally, lines have been rated conservatively. Careful analysis can discover the unused potential of existing facilities. Visualization tools can show the public the anticipated visual impact of a project prior to commencement.

Benefits: Avoids new right-of-way issues. The cost of upgrading the thermal rating has been estimated at approximately $7,000 per circuit mile, but reconductoring a 230 kV circuit costs on the order of $120,000 per mile compared with $230,000 per mile for a new steel-pole circuit (Lionberger and Duke 2001).

Barriers: This technology is making good inroads.

Commercial Status: Several companies offer commercial products and services.

Six-Phase and 12-Phase Transmission Line Configurations: The use of more than three phases for electric power transmission has been studied for many years. Using six or even 12 phases allows for greater power transfer capability within a particular right of way, and reduced EMFs because of greater phase cancellation. The key technical challenge is the cost and complexity of integrating such high-phase-order lines into the existing three-phase grid.

- Modular Equipment: One way to gain flexibility for changing market and operational situations is to develop standards for the manufacture and integration of modular equipment.

Objective: Develop substation designs and specifications for equipment manufacturers to meet that facilitate the movement and reconfiguration of equipment in a substation to meet changing needs.

Benefits: Reduces overall the time and expense for transmission systems to adapt to the changing economic and reliability landscape.

Barriers: Requires transmission planners and substation designers to consider a broad range of operating scenarios.

Also, developing industry standards can take a significant period, and manufacturers would need to offer conforming products.

Commercial Status: Utilities have looked for a certain amount of standardization and flexibility in this area for some time; however, further work remains to be done. National Grid (UK) has configured a number of voltage-support devices that use modular construction methods. As the system evolves, the equipment can be moved to locations where support is needed (PA Consulting Group 2001).

Ultra-High Voltage Levels: Because power is equal to the product of voltage times current, a highly effective approach to increasing the amount of power transmitted on a transmission line is to increase its operating voltage. Since 1969, the highest transmission voltage levels in North America have been 765 kV, (voltage levels up to 1,000 kV are in service elsewhere). Difficulties with utilizing higher voltages include the need for larger towers and larger rights of way to get the necessary phase separation, the ionization of air near the surface of the conductors because of high electric fields, the high reactive power generation of the lines, and public concerns about electric and magnetic field effects.

- *HVDC:* With active control of real and reactive power transfer, HVDC can be modulated to damp oscillations or provide power-flow dispatch independent of voltage magnitudes or angles (unlike conventional AC transmission).

  Objective: HVDC is used for long-distance power transport, linking asynchronous control areas, and real-time control of power flow.

  Benefits: Stable transport of power over long distances where AC transmission lines need series compensation that can lead to stability problems. HVDC can run independent of system frequency and can control the amount of power sent through the line. This latter benefit is the same as for FACTS devices discussed below.

  Barriers: Drawbacks include the high cost of converter equipment and the need for specially trained technicians to maintain the devices.

  Commercial Status: Many long-distance HVDC links are in place around the world. Back-to-back converters link Texas, WSCC, and the Eastern Interconnection in the U.S. More installations are being planned.

- *FACTS Compensators:* Flexible AC Transmission System (FACTS) devices use power electronics to adjust the apparent impedance of the system. Capacitor banks are applied at loads and substations to provide capacitive reactive power to offset the inductive reactive power typical of most power system loads and transmission lines. With long inter-tie transmission lines, series capacitors are used to reduce the effective impedance of the line. By adding thyristors to both of these types of capacitors, actively controlled reactive power are available using SVCs and TCSC devices, which are shunt- and series-controlled capacitors, respectively. The thyristors are used to adjust the total impedance of the device by switching individual modules. Unified power-flow controllers (UPFCs) also fall into this category.

  Objective: FACTS devices are designed to control the flow of power through the transmission grid.

  Benefits: These devices can increase the transfer capacity of the transmission system, support bus voltages by providing reactive power, or be used to enhance dynamic or transient stability.

  Barriers: As with HVDC, the power electronics are expensive and specially trained technicians are needed to maintain them. In addition, experience is needed to fully understand the coordinated control strategy of these devices as they penetrate the system.

  Commercial Status: As mentioned above, the viability of HVDC systems has already been demonstrated. American Electric Power (AEP) has installed a FACTS device in its system, and a new device was recently commissioned by the New York Power Authority (NYPA) to regulate flows in the northeast.

- *FACTS Phase-Shifting Transformers:* Phase shifters are transformers configured to change the phase angle between buses; they are particularly useful for controlling the power flow on the transmission network. Adding thyristor control to the various tap settings of the phase-shifting transformer permits continuous control of the effective phase angle (and thus control of power flow).

  Objective: Adjust power flow in the system.

  Benefits: The key advantage of adding power electronics to what is currently a non-electronic technology is faster response time (less then one second vs. about one minute). However, traditional phase shifters still permit redirection of flows and thereby increase transmission system capacity.

  Barriers: Traditional phase shifters are deployed today. The addition of the power electronics to these devices is relatively straightforward but increases expense and involves barriers similar to those noted for FACTS compensators.

Commercial Status: Tap-changing phase shifters are available today. Use of thyristor controls is emerging.

- *FACTS Dynamic Brakes:* A dynamic brake is used to rapidly extract energy from a system by inserting a shunt resistance into the network. Adding thyristor controls to the brake permits addition of control functions, such as on-line damping of unstable oscillations.

  Objective: Dynamic brakes enhance power system stability.

  Benefits: This device can damp unstable oscillations triggered by equipment outages or system configuration changes.

  Barriers: In addition the power electronics issues mentioned earlier, siting a dynamic brake and tuning the device in response to specific contingencies requires careful study.

  Commercial Status: BPA has installed a dynamic brake on their system.

- *Battery Storage Devices:* Batteries use converters to transform the DC in the storage device to the AC of the power grid. Converters also operate in the opposite direction to recharge the batteries.

  Objective: Store energy generated in off-peak hours to be used for emergencies or on-peak needs.

  Benefits: Battery converters use thyristors that, by the virtue of their ability to rapidly change the power exchange, can be utilized for a variety of real-time control applications ranging from enhancing transient to preconditioning the area control error for automatic generator control enhancement. During their operational lifetime, batteries have a small impact on the environment. For distributed resources, batteries do not need to be as large as for large-scale generation, and they become important components for regulating micro-grid power and allowing interconnection with the rest of the system.

  Barriers: The expense of manufacturing and maintaining batteries has limited their impact in the industry.

  Commercial Status: Several materials are used to manufacture batteries though large arrays of lead-acid batteries continue to be the most popular for utility installations. Interest is also growing in so-called “flow batteries” that charge and discharge a working fluid exchanged between two tanks. The emergence of the distributed energy business has increased the interest in deploying batteries for regional energy storage. One of the early battery installations that demonstrated grid benefit was a joint project between EPRI and Southern California Edison at the Chino substation in southern California.

- *Super-conducting Magnetic Energy Storage (SMES):* SMES uses cryogenic technology to store energy by circulating current in a super-conducting coil.

  Objective: Store energy generated in off-peak hours to be used for emergencies or on-peak needs.

  Benefits: The benefits are similar to those for batteries. SMES devices are efficient because of their super-conductive properties. They are also very compact for the amount of energy stored.

  Barriers: As with the super-conducting equipment mentioned in the passive equipment section above, SMES entails costs for the cooling system, the special protection needed in the event the super-conducting device quenches, and the specialized skills required to maintain the device.

  Commercial Status: Several SMES units have been commissioned in North America. They have been deployed at Owens Corning to protect plant processes, and at Wisconsin Public Service to address low-voltage and grid instability issues.

- *Pumped Hydro and Compressed-Air Storage:* Pumped hydro consists of large ponds with turbines that can be run in either pump or generation modes. During periods of light load (e.g., night) excess, inexpensive capacity drives the pumps to fill the upper pond. During heavy load periods, the water generates electricity into the grid. Compressed air storage uses the same principle except that large, natural underground vaults are used to store air under pressure during light-load periods.

  Objective: This technology helps shave peak and can help in light-load, high-voltage situations.

  Benefits: These storage systems behave like conventional generation and have the benefit of producing additional generation sources that can be dispatched to meet various energy and power needs of the system. Air emission issues can be mitigated when base generation is used in off-peak periods as an alternative to potentially high-polluting peaking units during high use periods.

Barriers: Pumped hydro, like any hydro generation project, requires significant space and has corresponding ecological impact. The loss of efficiency between pumping and generation as well as the installation and maintenance costs must be outweighed by the benefits.

Commercial Status: Pumped hydro projects are sprinkled across North America. A compressed-air storage plant was built in Alabama, and a proposed facility in Ohio may become the world's largest.

- *Flywheels:* Flywheels spin at high velocity to store energy. As with pumped hydro or compressed-air storage, the flywheel is connected to a motor that either accelerates the flywheel to store energy or draws energy to generate electricity. The flywheel rotors are specially designed to significantly reduce losses. Super conductivity technology has also been deployed to increase efficiency.

  Objective: Shave peak energy demand and help in light-load, high-voltage situations. As a distributed resource, flywheels enhance power quality and reliability.

  Benefits: Flywheel technology has reached low-loss, high-efficiency levels using rotors made of composite materials running in vacuum spaces. Emissions are not an issue for flywheels, except those related to the energy expended to accelerate and maintain the flywheel system.

  Barriers: The use of super-conductivity technology faces the same barriers as noted above under super-conducting cables and SMES. High-energy-storage flywheels require significant space and the high-speed spinning mass can be dangerous if the equipment fails.

  Commercial Status: Flywheel systems coupled with batteries are making inroads for small systems (e.g., computer UPS, local loads, electric vehicles). Flywheels rated in the 100 to 200 kW range are proposed for development in the near-term.

- *Price-Responsive Load:* Fast-acting load control is an important element in active measures for enhancing the transmission grid. Automatic load shedding (under-frequency, under-voltage), operator-initiated interruptible load, demand-side management programs, voltage reduction, and other load-curtailment strategies have long been an integral part of coping with unforeseen contingencies as a last resort, and/or as a means of assisting the system during high stress, overloaded conditions. The electricity industry has been characterized by relatively long-term contracts for electricity use. As the industry restructures to be more market-driven, adjusting demand based on market signals will become an important tool for grid operators.

  Objective: Inform energy users of system conditions though price signals that nudge consumption into positions that make the system more reliable and economic.

  Benefits: The approach reduces the need for new transmission and siting of new generation. Providing incentives to change load in appropriate regions of the system can stabilize energy markets and enhance system reliability. Shifting load from peak periods to less polluting off-peak periods can reduce emissions.

  Barriers: The vast number of loads in the system makes communication and coordination difficult. Also, using economic signals in real time or near-real time to affect demand usage has not been part of the control structure that has been used by the industry for decades. A common vision and interface standards are needed to coordinate the information exchange required.

  Commercial Status: Demand-management programs have been implemented in various areas of the country. These have relied on centralized control. With the advent of the Internet and new distributed information technology approaches, firms are emerging to take advantage of this technology with a more distributed control strategy.

- *Intelligent Building Systems:* Energy can be saved through increasing the efficient operation of buildings and factories. Coordinated utilization of cooling, heating, and electricity in these establishments can significantly reduce energy consumption. Operated in a system that supports price-responsive load, intelligent building systems can benefit system operations. Note: these systems may have their own, local generation. Such systems have the option of selling power to the grid as well as buying power.

Objective: Reduce energy costs and provide energy management resources to stabilize energy markets and enhance system reliability.

Benefits: Such systems optimize energy consumption for the building operators and may provide system operators with energy by reducing load or increasing local generation based on market conditions.

Barriers: These systems require a greater number of sensors and more complex control schemes than are common today. Should energy market access become available at the building level, the price incentives would increase.

Commercial Status: Pilot projects have been implemented throughout the country.

- *Distributed Generation (DG):* Fuel cells, micro-turbines, diesel generators, and other technologies are being integrated using power electronics. As these distributed resources increase in number, they can become a significant resource for reliable system operations. Their vast numbers and teaming with local load put them in a similar category to the controllable load discussed above.

  Objective: Address local demand cost-effectively.

  Benefits: DG is generally easier to site, entails smaller individual financial outlay, and can be more rapidly installed than large-scale generation. DG can supply local load or sell into the system and offers owners self-determination. Recovery and use of waste heat from some DG greatly increases energy efficiency.

  Barriers: Volatility of fuel costs and dependence on the fuel delivery infrastructure creates financial and reliability risks. DG units require maintenance and operations expertise, and utilities can set up discouraging rules for interconnection. System operators have so far had difficulty coordinating the impact of DG.

  Commercial Status: Deployment of DG units continues to increase. As with controllable load, system operations are recognizing the potential positive implications of DG to stabilize market prices and enhance system reliability though this requires a different way of thinking from the traditional, hierarchical control paradigm.

- *Power-System Device Sensors:* The operation of most of the individual devices in a power system (such as transmission lines, cables, transformers, and circuit breakers) is limited by each device's thermal characteristics. In short, trying to put too much power through a device will cause it to heat excessively and eventually fail. Because the limits are thermal, their actual values are highly dependent upon each device's heat dissipation, which is related to ambient conditions. The actual flow of power through most power-system devices is already adequately measured. The need is for improved sensors to dynamically determine the limits by directly or indirectly measuring temperature.

- *Direct Measurement of Conductor Sag:* For overhead transmission lines the ultimate limiting factor is usually conductor sag. As wires heat, they expand, causing the line to sag. Too much sag will eventually result in a short circuit because of arcing from the line to whatever is underneath.

  Objective: Dynamically determine line capacity by directly measuring the sag on critical line segments.

  Benefits: Dynamically determined line ratings allow for increased power capacity under most operating conditions.

  Barriers: Requires continuous monitoring of critical spans. Cost depends on the number of critical spans that must be monitored, the cost of the associated sensor technology, and ongoing cost of communication.

  Commercial Status: Pre-commercial units are currently being tested. Approaches include either video or the use of differential GPS. EPRI currently is testing a video-based "sagometer." An alternative is to use differential GPS to directly measure sag. Differential GPS has been demonstrated to be accurate significantly below half a meter.

- *Indirect Measurement of Conductor Sag:* Transmission line sag can also be estimated by physically measuring the conductor temperature using an instrument directly mounted on the line and/or a second instrument that measures conductor tension at the insulator supports.

Objective: Dynamically determine the line capacity.

Benefits: Dynamically determined line ratings allow for increased power capacity under most operating conditions.

Barriers: Requires continuous monitoring of critical spans. Cost depends upon the number of critical spans that must be monitored, the cost of the associated sensor technology, and ongoing costs of communication.

Commercial Status: Commercial units are available.

- *Indirect Measurement of Transformer Coil Temperature:* Similar to transmission line operation, transformer operation is limited by thermal constraints. However, transformers constraints are localized hot spots on the windings that result in breakdown of insulation.

  Objective: Dynamically determine transformer capacity.

  Benefits: Dynamically determined transformer ratings allow for increased power capacity under most operating conditions.

  Barriers: The simple use of oil temperature measurements is usually considered to be unreliable.

  Commercial Status: Sophisticated monitoring tools are now commercially available that combine several different temperature and current measurements to dynamically determine temperature hot spots.

- *Underground/Submarine Cable Monitoring/Diagnostics:* The below-surface cable systems described above require real-time monitoring to maximize their use and warn of potential failure.

  Objective: Incorporate real-time sensing equipment to detect potentially hazardous operating situations as well as dynamic limits for safe flow of energy.

  Benefits: Monitoring equipment maximizes the use of the transmission asset, mitigates the risk of failure and the ensuing expense of repair, and supports preventive maintenance procedures. The basic sensing and monitoring technology is available today.

  Barriers: The level of sophistication of the sensing and monitoring equipment adds to the cost of the cable system. The use of dynamic limits must also be integrated into system operation procedures and the associated tools of existing control facilities.

  Commercial Status: Newer cable systems are being designed with monitoring/diagnostics in mind. Cable temperature, dynamic thermal rating calculations, partial discharge detection, moisture ingress, cable damage, hydraulic condition (as appropriate), and loss detection are some of the sensing functions being put in place. Multi-functional cables are also being designed and deployed (particularly submarine cables) that include communications capabilities. Monitoring is being integrated directly into the manufacturing process of these cables.

- *Direct System-State Sensors:* In some situations, transmission capability is not limited by individual devices but rather by region-wide dynamic loadability constraints. These include transient stability limitations, oscillatory stability limitations, and voltage stability limitations. Because the time frame associated with these phenomena is much shorter than that associated with thermal overloads, predicting, detecting and responding to these events requires much faster real-time state sensors than for thermal conditions. The system state is characterized ultimately by the voltage magnitudes and angles at all the system buses. The goal of these sensors is to provide these data at a high sampling rate.

- *Power-System Monitors*

  Objective: Collect essential signals (key power flows, bus voltages, alarms, etc.) from local monitors available to site operators, selectively forwarding to the control center or to system analysts.

  Benefits: Provides regional surveillance over important parts of the control system to verify system performance in real time.

  Barriers: Existing SCADA and Energy Management Systems provide low-speed data access for the utility's infrastructure. Building a network of high-speed data monitors with intra-regional breadth requires collaboration among utilities within the interconnected power system.

  Commercial Status: BPA has developed a network of dynamic monitors collecting high-speed data, first with the power system analysis monitor

(PSAM), and later with the portable power system monitor (PPSM), both early examples of WAMS products.

- *Phasor Measurement Units (PMUs)*

  Objective: PMUs are synchronized digital transducers that can stream data, in real time, to phasor data concentrator (PDC) units. The general functions and topology for this network resemble those for dynamic monitor networks. Data quality for phasor technology appears to be very high, and secondary processing of the acquired phasors can provide a broad range of signal types.

  Benefits: Phasor networks have best value in applications that are mission critical and that involve truly wide-area measurements.

  Barriers: Establishing PMU networks is straightforward and has already been done. The primary impediment is cost and assuring value for the investment (making best use of the data collected).

  Commercial Status: PMU networks have been deployed at several utilities across the country.

BIOGRAPHY FOR JAMES W. GLOTFELTY

Jimmy Glotfelty is currently Director of the Office of Electric Transmission and Distribution at the Department of Energy. This new office was established by Secretary Spencer Abraham to focus attention on the policy and research and development needs of the Transmission and Distribution systems. Prior to this position, he served as Senior Policy Advisor to Secretary Abraham. He is senior leader in the implementation of President Bush's National Energy Policy. He advises the Secretary on policy concerning electricity, transmission, interconnection, siting, and other areas within the DOE. He works closely with members of Congress and members of the FERC in order to ensure that we continue to move toward competitive wholesale electric markets. He is also responsible for the development of the national grid study to identify major bottlenecks across the U.S.

Prior to joining the DOE, Jimmy served as Director of Government and Regulatory Affairs for Calpine Corporation's Central Region. He actively pursued restructured markets and new wholesale and retail markets for new power generation companies in Texas, Louisiana, Alabama, and Mexico. In addition to government affairs, Jimmy oversaw Calpine's Central Region public affairs efforts.

From 1994 to 1998, Jimmy served as Director of General Government Policy and Senior Energy Advisor to Governor George W. Bush. He spearheaded many oil and gas initiatives, served as the Governor's office point staff member on both wholesale and retail electric restructuring in Texas, and oversaw the Texas State Energy Office. In addition to energy issues, Jimmy founded and managed the Governors High Technology Council, and was responsible for policy initiatives in the telecommunications, banking, housing, and pension arenas.

During his career, Jimmy was Legislative Director for Congressman Sam Johnson (R–TX) where he was responsible for all legislative operations as well as energy, banking, and telecommunications issues. Jimmy has also served as Finance Director for the Republican Party of Texas and as Research Director for the lobby and public affairs firm Dutko and Associates.

Jimmy resides in Arlington, VA with his wife, Molly, and sons, Chase and Walker.

Chairwoman BIGGERT. Thank you so much.

Mr. Glauthier is recognized. Am I pronouncing that correctly?

Mr. GLAUTHIER. Yes, that is fine. Glauthier. Thank you.

Chairwoman BIGGERT. Glauthier. Thank you.

STATEMENT OF MR. T.J. GLAUTHIER, PRESIDENT AND CEO, ELECTRICITY INNOVATION INSTITUTE, PALO ALTO, CA

Mr. GLAUTHIER. Thank you, Madame Chair and Members of the Subcommittee. I am T.J. Glauthier, the President and CEO of the Electricity Innovation Institute, an affiliate of EPRI, the Electric Power Research Institute. With me today, also, is Dr. Dan Sobajic, the Director of Grid Reliability and Power Markets at EPRI. I am here today testifying on behalf of both organizations. I will summarize my testimony.

As you know, EPRI is a non-profit scientific organization formed by U.S. electric utilities 30 years ago to manage a collaborative research program on behalf of utilities, their customers, and society. Today, EPRI has more than 1,000 members, including utilities of all owner types, independent system operators and independent power producers, and others. Electricity Innovation Institute was formed two years ago by the EPRI Board of Directors as an affiliated public benefit organization to sponsor long-term strategic R&D programs through public/private partnerships. Its Board of Directors is primarily composed of independent, bipartisan, public representatives.

Both organizations are already actively engaged in R&D to modernize the electricity grid. Two years ago, in response to the events of September 11, 2001, an interdisciplinary EPRI team prepared a preliminary analysis of potential terrorist threats to the U.S. electricity system. Out of this effort grew an infrastructure security initiative, which has undertaken a short-term, tightly focused effort to identify key vulnerabilities and to design immediately applicable countermeasures.

In addition, we recently have begun work with the Department of Homeland Security in which we are bringing utilities and ISOs together with DHS to help develop a system for them to monitor the security of the national power grid in real time. Now, after the power outage of August 14, EPRI is actively supporting the U.S./Canada joint task force working with DOE and the North American Electric Reliability Council, NERC.

There are several current technologies that could be more widely used today to increase system reliability and security. First, there are gaps in the coverage of SCADA and EMS systems, which should be remedied. Second, system operators need to have greater visibility into what is happening in neighboring control areas. EPRI, Department of Energy, and others have demonstrated systems that could do this. Third, State estimators, systems that are needed for real time management of the grid, are not being fully utilized in many control areas today. And finally, there are some technologies that are either ready now or in nearing commercial availability, which include a Dynamic Thermal Circuit Rating system for improved management of transmission lines, new advanced high-temperature, lightweight conductors or transmission lines, which are undergoing testing by EPRI and the Department of Energy as noted by the previous witness, and FACTS devices, Flexible AC Transmission Systems that can control direct power flows, including loop flows.

All of this is a precursor to the smart grid, which will be the modernization of the electricity transmission and distribution system to be an intelligent, always on, self-healing grid. It will recognize power system vulnerabilities and alert operators to them, and in the event of a failure, will automatically island off those areas to isolate the problem. Smart grid will also support a more diverse and complex network of energy technologies, including an array of locally installed distributed power sources, such as fuel cells, solar power, and combined heat and power systems. This will give the system greater resilience, enhance security, and improve reliability. We believe such a smart grid will yield significant benefits both in power—in reducing the cost of power disturbances to the economy and in enabling a new phase of entrepreneurial innovation, which will, in turn, accelerate energy efficiency, productivity, and economic growth for the Nation.

We offer four recommendations for the Energy Bill and have submitted legislative language to carry these out. First, to establish the smart grid as a national priority. This could increase the pace and level of commitment to the modernization of the electricity grid. Second, to authorize increased funding for R&D and for an aggressive program of technology demonstration and early deployment projects. We estimate that this will require increased federal funding for the Department of Energy on the scale of approximately $1 billion over the next five years, with the private sector contributing a significant amount of matching funding. Third, recognize a public/private institutional role for the R&D. It is vitally important that this program be carried out in partnership with the private sector. It is the industry that will ultimately be responsible for building, maintaining, and operating the electricity system to keep the lights on. This is more than a research program; it is an engineering and operations program on which the country will rely. And finally, develop a national approach for long-term funding of deployment, which will require approximately $100 billion over a decade, $10 billion a year for 10 years. We need a national financing approach that will be effective, fair, and equitable for all parts of society. We urge the Congress to include language in the Energy Bill that directs the Administration to work with the industry, the states, customers, and others to develop a recommendation and report back one year after enactment.

In conclusion, this committee and the Congress can play a pivotal role in leading the modernization of the Nation's electricity infrastructure for the 21st century.

Thank you, Madame Chair. I welcome any questions.

[The prepared statement of Mr. Glauthier follows:]

PREPARED STATEMENT OF T.J. GLAUTHIER

Thank you, Madam Chair, I am T.J. Glauthier, President and CEO of the Electricity Innovation Institute, an affiliate of EPRI, the Electric Power Research Institute. With me today is Dejan Sobajic, Director of Grid Reliability and Power Markets at EPRI.

As you know, EPRI is a non-profit, tax-exempt, scientific organization formed by U.S. electric utilities in 1972 to manage a national, public-private collaborative research program on behalf of EPRI members, their customers, and society. Today EPRI has more than 1,000 members, including utilities of all owner types (both U.S.-based and international), independent system operators (ISOs), independent power producers, and government agencies, collectively funding an electricity-related scientific research and technology development program that spans every aspect of power generation, delivery, and use.

The Electricity Innovation Institute (E2I), formed two years ago by the EPRI Board of Directors as an affiliated non-profit, public benefit organization, sponsors longer-term, strategic R&D programs through public-private partnerships. Its Board of Directors is primarily composed of independent, bipartisan, public representatives.

E2I is already actively engaged in modernizing the electricity grid. For example, with technical support from EPRI, 18 months ago we began a public-private R&D partnership to design and develop the system of technologies enabling a self-healing, 'smart grid.' This partnership involves a number of public and private utility companies, the Department of Energy (DOE), several states, and the high tech industry. It has one multi-million dollar contract underway, with a team that includes General Electric, Lucent Technologies and others, to design an 'open architecture' for the smart grid.

EPRI and E2I actively support the dialogue on national energy legislation by providing objective information and knowledge on energy technology, the electricity system and related R&D issues.

I sincerely appreciate the opportunity to address this distinguished Committee on a subject about which we are all concerned. The electric power system represents the fundamental national infrastructure, upon which all other infrastructures depend for their daily operations. As we learned from the recent Northeast blackout, without electricity, municipal water pumps don't work, vehicular traffic grinds to a halt at intersections, subway trains stop between stations, and elevators stop between floors. The August 14th blackout also illustrated how vulnerable a regional power network can be to cascading outages caused by initially small—and still not fully understood—local problems.

In response to the Committee's request, my testimony today provides some of EPRI's and E2I's views on technology issues that require further attention to improve the effectiveness and reliability of the Nation's interconnected power systems. This testimony will be supplemented with a matrix table as requested by the Committee.

Context for power reliability

Power system reliability is the product of many activities—planning, maintenance, operations, regulatory and reliability standards—all of which must be considered as the Nation makes the transition over the longer-term to a more efficient and effective power delivery system. While there are specific technologies that can be more widely applied to improve reliability both in the near- and intermediate-term, the inescapable reality is that there must be more than simply sufficient capacity in both generation and transmission in order for the system to operate reliably.

The emergence of a competitive market in wholesale power transactions over the past decade has consumed much of the operating margin in transmission capacity that traditionally existed and helped to avert outages. Moreover, a lack of incentives for continuing investment in both new generating capacity and power delivery infrastructure has left the overall system much more vulnerable to the weakening effects of what would normally be low-level, isolated events and disturbances.

Two years ago, in response to the events of September 11, 2001, an inter-disciplinary EPRI team prepared the *Electricity Infrastructure Security Assessment,* a preliminary analysis of potential terrorist threats to the U.S. electricity system. Out of this effort grew the Infrastructure Security Initiative (ISI), which has undertaken a short-term, tightly focused effort to identify key vulnerabilities and design immediately applicable countermeasures. The initial phase of the ISI has been completed and work is now underway to implement some of the technological solutions identified. More recently, E2I and EPRI began work with the Department of Homeland Security (DHS) to establish the National Electric Infrastructure Security Monitoring System (NESEC). This system will enable DHS to monitor the security of the national power grid in real time and can be used to identify and diagnose unusual events that might signal a terrorist attack in its early stages. Such a system could also be used to monitor grid operations for disturbances with potential to impact reliability.

The electric power industry is one of the most data intensive and computing power-reliant of all industries, with Supervisory Control and Data Acquisition (SCADA) systems collecting data and sending control signals over wide geographical regions, in conjunction with the analytical functions performed by highly computerized Energy Management Systems (EMS).

EPRI is actively supporting the U.S.-Canada Joint Task Force on the power outage of August 14th, working with DOE and the North American Electric Reliability Council (NERC). Based on information assembled and published by the task force so far, some basic, bottom-line preliminary implications can be drawn. One is that better, more complete information about system conditions in the affected region could have enabled quicker response by the various system operators, which might have helped avert so widespread an outage.

A significant weakness of the North American power system is that, despite the computing power that is applied, not all parts of the power system are presently covered by SCADA and EMS systems. There are gaps in coverage, and some critical parameters must be computed from other measurements. EPRI strongly recommends that the industry move toward completing the data picture by ensuring that all transmission facilities down to the 169-kilovolt level are fully measurable and observable—in real time—for five key parameters: active power, reactive power, current, voltage, and frequency. In addition, each of the 150 individual control areas need to implement complete SCADA coverage for the entire system.

Seeing the bigger picture

System operators also need the capability for a wide-area view of what is happening in neighboring control areas. This would represent a major improvement over existing conditions, under which operators cannot access the same level of information on neighboring systems that they have on their own system. Two years ago, in cooperation with NERC, EPRI conducted an R&D project sponsored under the industry-funded Reliability Initiative, which demonstrated an integrated, real-time visualization of the nationwide interconnected system, incorporating data on critical operating measurements from each control center, using the Internet for communication. There are similar demonstration efforts underway by other organizations as well. For a relatively modest cost, such a system could be made available to all system operators.

A related issue involves interpretation and analysis of the operating data from SCADA and EMS systems. EMS application software programs known as state estimators are employed to process data and compute values for system parameters that are not measured. Results are critical for doing more complex analyses, such as contingency analyses of the impact of losing various system elements, such as power plants or transmission lines. Yet because of low confidence in the computed results for real-time decision-making, very few control center EMS state estimators are fully utilized today. EPRI believes that credible, complete information from operational state estimators is essential for reliability and should be required in all control areas.

Near-term solutions

One relatively simple technology developed by EPRI and successfully demonstrated by several utilities could contribute to improved system reliability by enabling increased confidence of safe loading levels for transmission lines above their conservative static ratings. By integrating real-time sensor data on ambient temperature, wind speed, and line sag on specific circuits, EPRI's Dynamic Thermal Circuit Rating (DTCR) system allows operators to move more power on lines with reduced risk of thermal overload. DTCR is low-cost and can be quickly deployed on thermally constrained lines. Such dynamic line ratings, along with more complete SCADA coverage, would represent key inputs for more probabilistic-based contingency analyses of system instability. Such probabilistic-based analyses could extend the scope of contingencies considered from the loss of a single transmission line or generating source (N–1 contingency), which is the current criterion, to the simultaneous loss of multiple lines or generators (N–2 contingency).

On the hardware side of T&D systems, a mid-term solution for increasing the capacity of existing transmission corridors may soon be ready for commercial deployment: advanced high-temperature, low-sag conductors. These advanced conductors have the potential to increase current carrying capacity of thermally constrained transmission lines by as much as 30 percent or more. Five new types of aluminum conductor designs, reinforced or supported with steel or composite material, are being investigated by EPRI in collaboration with member utilities. One type is already under field test in a project with CenterPoint Energy in Houston; it also promises more rapid installation, since it has already been demonstrated that the conductors can be strung while energized. This work complements related ongoing activity supported by DOE's Office of Electric Transmission and Distribution, including testing activity at Oak Ridge National Laboratory.

Facing up to loop flows

Numerous knowledgeable power system engineers have warned for many years that the phenomenon of loop flow would eventually have important implications for reliability, but those warnings have largely gone unheeded with the emergence of a competitive, wholesale bulk electricity market. Preliminary indications are that loop flows of power around the Lake Erie region may have played a role in the Aug. 14th blackout.

Loop flows are a key unresolved issue facing the industry today in terms how the power system status appears to operators, yet such flows generally are not accounted for in day-to-day operations. Loop flows result from the basic physics of electricity, which follows all available paths of least resistance, rather than a single line on a contract path from point A to point B. These loop flows have been present ever since power grids began to become interconnected, but only recently have loop flows reached a level sufficient to cause problems. With today's reduced operating margins of transmission capacity, they can make the difference between safe operating conditions and system overload.

Loop flows can be controlled with solid-state power electronics technology, such as Flexible AC Transmission Systems (FACTS) technology developed by EPRI and power equipment vendors, but specific operating practices are necessary that require EMS state estimator information to establish proper settings for mitigation. FACTS technologies deployed in various configurations promise a new dimension of high-speed control flexibility to change the power system state and react to changes in ways that we cannot today. However, FACTS technologies are still emerging and their cost and size must be further reduced through continued R&D efforts before they are economical for widespread deployment.

In addition to DTCR and improved data exchange standards and system information coverage, other near-term steps that could contribute to improved reliability include improved operator training, both for normal operation under heavy loading conditions and for service restoration from outages. Operators require more information in order to perform restoration procedures than are required under normal operating conditions. Reiterating the importance of a holistic approach to reliability, transmission and distribution infrastructure maintenance should be afforded the same priority as system planning, operations, and energy marketing that are addressed by standing NERC standards committees.

Given that energy legislation now under consideration by the Congress would establish mandatory, enforceable reliability standards under NERC supervision, such standards should specifically address requirements for the provision of, and compensation for, reactive power for voltage support. Although the significance of this somewhat arcane component of alternating current transmission is lost on many people not trained in electrical engineering, its critical importance in the operation of interconnected systems and long distance transmission cannot be overemphasized. Reactive power is a non-billable, but essential, component of real or active power that helps maintain voltage and is critical for magnetizing the coils in large inductive loads so they can start up and begin drawing real power.

Intermediate term measures

Beyond the more immediate steps and technologies available for boosting power system reliability, development of a number of emerging technologies that are still not yet ready for commercial deployment could benefit from increased industry and government support for demonstration efforts. These include the demonstration and integration of new inter-system communication standards based on open protocols to enable data exchange among equipment from different vendors, including SCADA and EMS systems. Two prime examples of such standards are the EPRI-developed Utility Communications Architecture for connecting equipment from different vendors and the Inter-Control Area Communication Protocol for linking control centers and regional transmission organizations.

As described more fully below, EPRI's ultimate vision for the future of power delivery is an electronic, self-healing, adaptive 'smart' power grid. However, realizing this vision fully will require development, demonstration, and integration over the next decade of key elements that do not yet exist, such as intelligent software to reconfigure systems to prevent blackouts. Yet features of the self-healing grid of the future can be demonstrated today using off-the-shelf, recently developed technologies. Such demonstrations could begin providing near-term benefits during the next several years, before the complete vision of a 'smart' grid becomes reality within the next decade.

The Electricity Innovation Institute (E2I), a non-profit affiliate of EPRI established to pursue public-private partnerships for strategic electricity R&D, is proposing just such a partnership to demonstrate Dynamic Risk and Reliability Management (DRRM). The proposed effort would develop and demonstrate a set of real-time tools to enable system operators to see and quickly react to grid conditions that threaten to cause outages. Unlike existing technologies, the tool set will combine a picture of real-time vulnerabilities with an assessment of the status of grid components to pinpoint "hot spots," or areas where equipment failure could precipitate a widespread outage. Existing tools focus on monitoring the health of equipment *or* monitoring the status of the grid, but have not yet been effectively combined into one tool capable of providing a clear picture of overall risk. DRRM requires all the previously mentioned short-term improvements in data integrity and coverage in order to be effective.

E2I is proposing to take maximum advantage of ongoing R&D to develop and implement a working demonstration of DRRM in the shortest possible time. Tools such as the EPRI-developed Maintenance Management Workstation for transmission substations, Probabilistic Risk Assessment for contingency analyses, Visualization of transmission conditions via EPRI's Community Activity Room™ software, Transformer Advisor expert diagnostic system, and others will be brought together to support DRRM development.

E2I is already engaged with several utility partners anxious to demonstrate DRRM tools on their transmission systems. The proposed work will require investment of $10 million to $20 million and take approximately two years to complete. Once demonstrated, DRRM will be designed for rapid deployment by transmission operators and RTOs. Results of using DRRM would provide the quantitative basis to support risk-based revisions to contingency analyses, reliability criteria, and operating practices.

Adaptive, self-healing response at the speed of light

The smart grid encompasses both the long distance transmission system and the local distribution systems. Central to the concept is that it incorporate ubiquitous sensors throughout the entire delivery system and facilities, employ instant communications and computing power, and use solid-state power electronics to sense and, where needed, control power flows and mitigate disturbances instantly. The upgraded system will have the ability to read and diagnose problems, and in the event of a disruption from either natural or man-made causes, it will be 'self-healing' by automatically isolating affected areas and re-routing power to keep the rest of the system up and running. It will be alert to problems as they unfold, and able to respond at the speed of light.

Another advantage of the smart grid is that it will be able to support a more diverse and complex network of energy technologies. Specifically, it will be able to seamlessly integrate an array of locally installed, distributed power sources, such as fuel cells, solar power, and combined heat and power systems, with traditional central-station power generation. This will give the system greater resilience, enhance security and improve reliability. It will also provide a network to support new, more energy efficient appliances and machinery, and offer intelligent energy management systems in homes and businesses. For utilities and their customers, 'smart' grid technology could also enable the incorporation of significant amounts of electricity stored in battery systems, flywheels, compressed-air, and other forms of storage, when they are economical, for load management, voltage support, frequency regulation, and other beneficial applications, including providing a buffer between sensitive equipment and momentary power disturbances.

The enhanced security, quality, reliability, availability, and efficiency of electric power from such a smart grid will yield significant benefits. It will strengthen the essential infrastructure that sustains our homeland security. Moreover, it will reduce the cost of power disturbances to the economy, which have been estimated by EPRI to be at least $100 billion per year—and that's in a normal year, not including extreme events, such as the recent outage. Further, by being better able to support the digital technology of business and industry, the smart grid will also enable a new phase of entrepreneurial innovation, which will in turn accelerate energy efficiency, productivity and economic growth for the Nation.

The economic benefits of the smart grid are difficult to predict in advance, but they will consist of two parts. These are stemming the losses to the U.S. economy from power disturbances of all kinds, which are now on the order of one percent of U.S. gross domestic product, and taking the brake off of economic growth that can be imposed by an aging infrastructure.

Electricity Sector Framework for the Future

On August 25, 2003, EPRI released a report on the current challenges facing the electricity sector in the U.S., outlining a Framework for Action. The report, the *Electricity Sector Framework for the Future (ESFF),* was completed prior to the August 14 outage, and was developed over the past year under the leadership and direction of the EPRI Board of Directors.

EPRI engaged more than 100 organizations and held a series of regional workshops, including a diverse group of stakeholders—customers, suppliers, elected officials, environmentalists, and others—in producing the Framework. That dialogue provided valuable insights into the causes of problems, such as the disincentives for investment and modernization in transmission facilities, which have become much more widely recognized since the August outage.

The ESFF report lays out a coherent vision of future risks and opportunities, and of a number of the issues that must be dealt with in order to reach that future. It also reflects viewpoints widely shared by the broader electricity stakeholder community that contributed to its development. Its vision of the future will be based on a transformed electricity infrastructure that is secure, reliable, environmentally friendly, and imbued with the flexibility and resilience that will come from modern digital electronics, communications, and advanced computing.

But to arrive at that future, many parties must take action in the near-term. The report calls upon Congress to take action in a number of areas, such as establishing mandatory reliability standards, clarifying regulatory jurisdictions, and helping to restore investor confidence in the electricity sector so that needed investments can be made.

EPRI President and CEO Kurt Yeager and I presented a staff briefing on the *Electricity Sector Framework for the Future* that was hosted by this committee on September 11, 2003. The full ESFF report is also publicly available.

Recommended Congressional action

Current legislation under consideration by Congress contains some good provisions in support of technology development, but the national transformation of the grid is so important that it requires stronger action and support from the Congress in the energy bill. EPRI submitted specific legislative language, focusing on the technology and R&D areas that we believe are vital to modernizing the Nation's electricity transmission and distribution grid, to the House and Senate leadership who are currently meeting to discuss H.R. 6. In addition, there are four key areas of technology policy that the energy legislation should address, as described below:

1. Establish the 'Smart Grid' as a national priority

Congress can provide real leadership for the country by establishing the 'smart grid' as national policy and as a national priority in the legislation. By articulating this as national policy and offering a compelling vision for the country, Congress can increase the pace and level of commitment to the modernization of the electricity grid.

That action itself will help to focus the attention of the federal and State agencies and the utility industry and others in the private sector. By making the smart grid a national priority, Congress will be sending a clear message that this modernization is critically important in all sectors and in all regions of the country, and that deployment should be undertaken rapidly.

2. Authorize increased funding for R&D and demonstrations

To carry through with the priority of the smart grid, the legislation should include significantly increased development funding. In particular, it should contain authorization for significant additional appropriations over the next five years for programs managed by DOE, working in partnership with the private sector.

The Administration has taken some steps in this direction in its earlier budgets, but this demands even stronger, more targeted action by the Congress. Support is needed in two areas. One is more extensive R&D in the relevant technologies, needed to provide all the components of the smart grid. The other area is to support an aggressive program of technology demonstration and early deployment projects with the states and the industry, to prove out these components, and to refine the systems engineering which integrates all these technologies in real-world settings.

EPRI estimates that this research and demonstration program will require increased federal funding for R&D on the scale of approximately $1 billion, spread out over five years, with the private sector contributing a significant amount of matching funding. These R&D and demonstration funds represent an investment that will stimulate deployment expenditures in the range of $100 billion from the owners and operators of the smart grid, spread out over a decade.

3. Recognize a public/private institutional role for R&D

It is vitally important that the legislation recognize that this R&D and demonstration program should be carried out in partnership with the private sector. The government can sponsor excellent technical research. However, it is the industry that will ultimately be responsible for building, maintaining and operating the electricity system to keep the lights on and the computers humming. And as we've just seen, there is little tolerance for error—it has to work all the time—so this is more than a research program, it is an engineering and operations program on which the country will rely.

4. Develop an approach for long-term funding of deployment

A national approach is needed to fund the full-scale deployment of the smart grid throughout the country. The scale of deploying the technology, and doing the detailed systems engineering to make it work as a seamless network, will require significant levels of investment, estimated at $100 billion over a decade.

These implementation costs for the smart grid will be an investment in the infrastructure of the economy. This investment will pay back quickly in terms of reduced costs of power disturbances and increased rates of economic growth.

Nevertheless, this is a substantial challenge for an industry that is already under financial strain, and is lacking investment incentives for the grid. It's a challenge, too, because this investment must be new and additional to what the industry and its customers are already providing to keep the current systems operating. A business-as-usual approach will not be sufficient.

We need a national financing approach or mechanism that will be effective, fair, and equitable to all parts of society. This will require agreement among the industry, state regulatory commissions, customers and other stakeholders as to how that should be carried out.

The answer to this will undoubtedly take extended discussions with the various stakeholder groups. Rather than rush to judgment on one or another specific approach, we urge that Congress include language in the energy bill to direct the Administration to develop an appropriate recommendation. The Administration should work with the industry, the states, customers, and other to develop its recommendation and report back to Congress at a specific time, no later than one year after enactment.

Conclusion

As noted earlier, the cost of developing and deploying the smart grid for the country should be thought of as an investment in the future—in a secure, reliable, and entrepreneurial future—that will pay back handsomely over many decades to come as the energy backbone of the 21st century.

Thank you, Madam Chair. I welcome any questions you may have.

BIOGRAPHY FOR T.J. GLAUTHIER

T.J. Glauthier is President and Chief Executive Officer of the Electricity Innovation Institute (E2I), which sponsors strategic R&D programs through public/private partnerships. He has managed the start-up of this new organization, which began full operation in January of 2002. As CEO, he is ultimately responsible for all operations and performance of E2I, including overseeing the activities of the other officers, reporting to the Board of Directors, and coordinating with EPRI and its other affiliated organizations. In addition, he takes an active role in the strategic direction of key programs, such as the CEIDS program to develop the new technologies needed to transform the transmission and distribution electricity infrastructure into a self-healing, 'smart grid' to increase security, reliability and flexibility.

Prior to joining the Institute, Mr. Glauthier was the Deputy Secretary and Chief Operating Officer of the U.S. Department of Energy from 1999 to 2001. In that capacity, he directed the day-to-day management and policy development of the Department's over 120,000 federal and contractor employees and $18 billion annual budget. In his COO role, Mr. Glauthier had broad oversight across all four of the Department's major lines of business: Defense, Science, Energy, and Environment. He was also responsible for the corporate offices, such as policy, International Affairs, the CFO, procurement, and personnel. Mr. Glauthier also testified before Congress, coordinated with the White House and other agencies, and represented the Department and the President in national and international forums.

Before coming to the Energy Department, from 1993 to 1998, Mr. Glauthier served for five years in the Office of Management and Budget as the Associate Director for Natural Resources, Energy and Science. In that capacity, he and his staff of 70 served as the key link between the Executive Office of the President and agencies such as the Departments of Agriculture, Energy, and Interior, the EPA, NASA, NSF, the Army Corps of Engineers, and a number of smaller or independent agencies, such as the Smithsonian Institution, the Kennedy Center, and TVA, together accounting for over $60 billion in annual discretionary appropriations and over 350,000 federal and contract employees.

Earlier, Mr. Glauthier spent over twenty years in management consulting. For most of that time, he was with Temple, Barker & Sloane, Inc., where he began as a specialist on corporate and financial planning for Fortune 500 companies, and later became the Vice President in charge of the firm's Public Policy and Management Group.

Immediately prior to joining the Clinton Administration, Mr. Glauthier spent three years as Director of Energy and Climate Change at the World Wildlife Fund, where he dealt with technology transfer, the climate change treaty, and the 1992 Earth Summit in Rio de Janeiro.

Mr. Glauthier is a graduate of Claremont Men's College and the Harvard Business School.

Chairwoman BIGGERT. Thank you very much.

And now, Dr. Smith. Would you turn on your microphone, so that the green light is lit?

STATEMENT OF DR. VERNON L. SMITH, NOBEL LAUREATE, PROFESSOR AT GEORGE MASON UNIVERSITY

Dr. SMITH. Thank you, Madame Chair. It is a pleasure for me to be here and to have the opportunity to make, perhaps, a small contribution to a very large problem.

To me, the basic problem is not at the transmission level; it is in the—it is between the substation and the end-use consumer. That is the area in the entire electric power system, which has been a—is still—basically is locked in 1930's technology, and there is no incentive there to innovate. And I—to me, and that gives us an extremely inflexible demand side system.

And it is—for example, it is very vulnerable. You couldn't—I can't imagine designing a more vulnerable electric power system to terrorist attack. You are from Chicago. Suppose terrorists take out half of the supply of energy to Chicago. Utilities have no option but to shed—but to turn off half of the substations. It is much better to turn off the lowest half priority of power, not everything below a substation. If—and it is fundamentally an incentive problem, an incentive to innovate prices and an incentive to develop the kinds of technologies that both fit consumer preferences and enable the energy suppliers to profit from providing those services.

I want to show a slide.

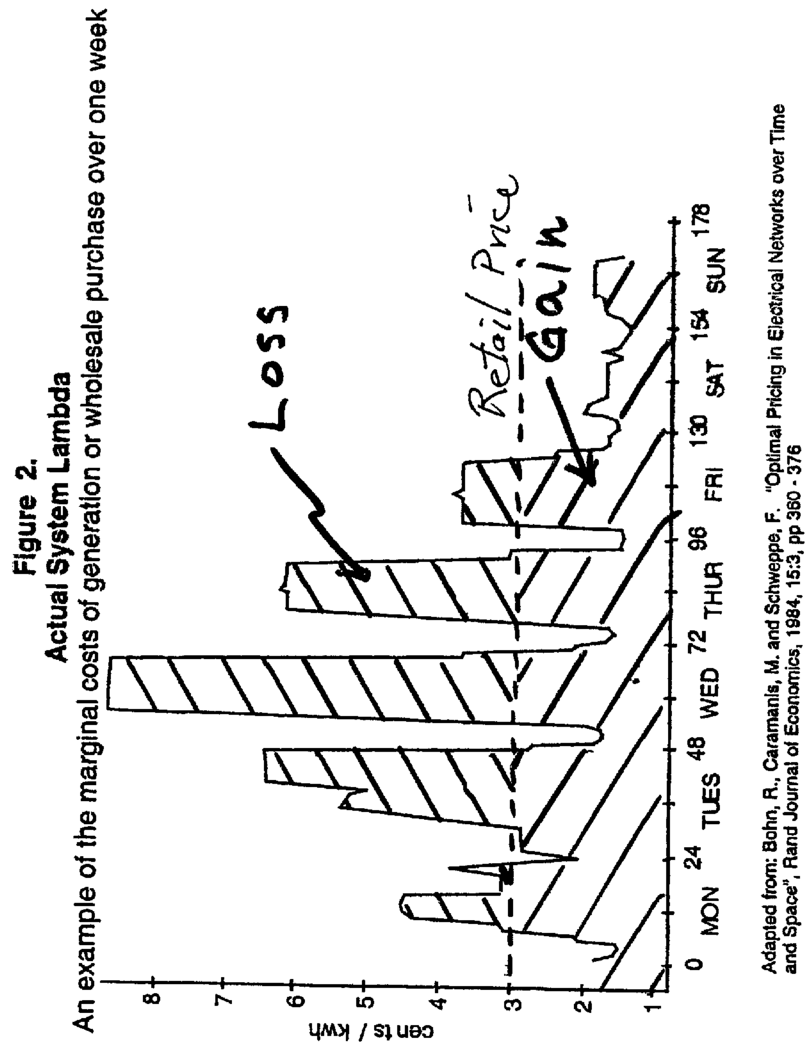
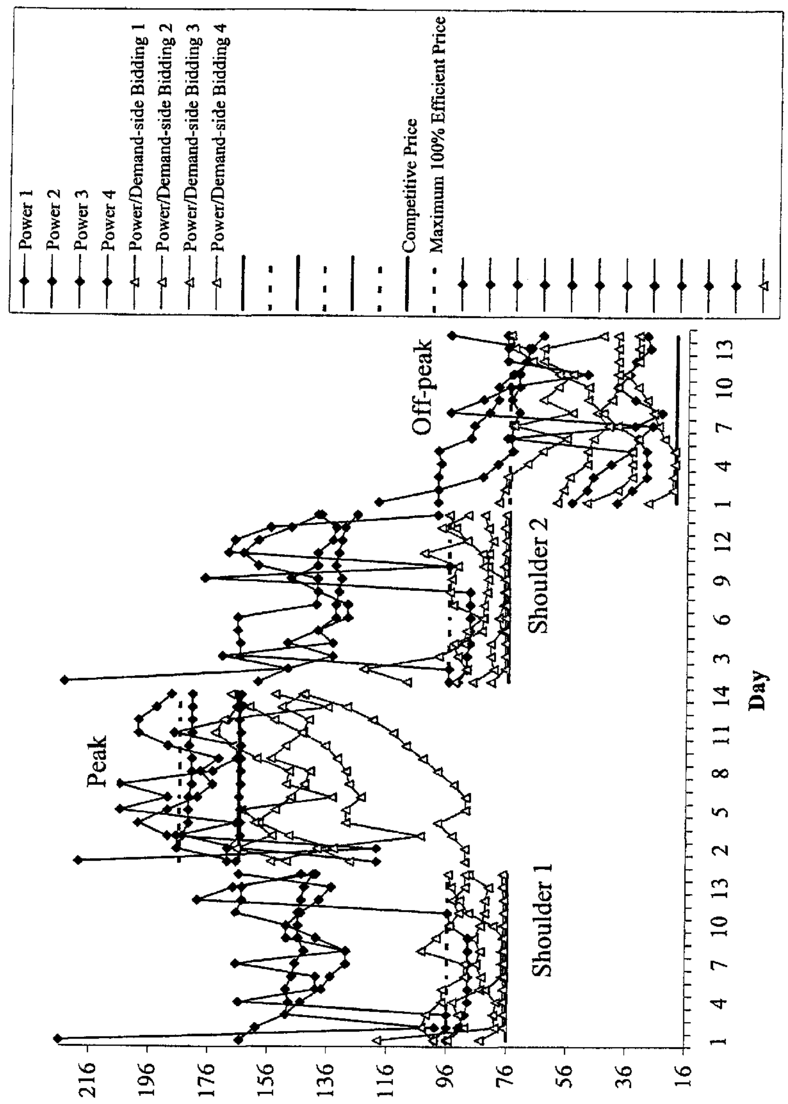


Figure 2.
Actual System Lambda
An example of the marginal costs of generation or wholesale purchase over one week

Adapted from: Bohn, R., Caramanis, M. and Schweppe, F. "Optimal Pricing in Electrical Networks over Time and Space", Rand Journal of Economics, 1984, 15:3, pp 360 - 376

And I—let me apologize for the old technology here, but it is—this is a—this slide shows the variation in just the marginal cost of energy in the Midwest. This is a period in the '80's in a hot August week. It is the hourly variation and the cost of just the energy component of people's bills. At the time, the energy component of people's bills would have been a flat, roughly three cents a kilowatt. And you will notice that actual costs are peaking as high as 8½ cents and as low as 1½ cents. That is the kind of variability you have when the system is strained. And it—whether it is strained enough to take out transmission lines still, it happens very, very commonly. Notice here what that means is that the peak users are imposing costs on the system that are far larger than the price they are paying. In effect, the utility is subsidizing peak consumption. It is sending signals—a signal that says dry your clothes at 3 p.m. in the afternoon, okay. And off-peak, the—basically the users are being taxed, because they are paying a price much above the marginal cost of producing the energy.

If I could have the second slide, please.



I want to show you the effect of laboratory experiments comparing—this is a—these are two-sided spot markets made by human subjects who profit from—the wholesale buyers are profiting by trying to buy power low and reselling it to customers. Generator owners are attempting to profit by selling power above their cost of generation. It is a two-sided market. And what we are comparing is the effect of demand side bidding where you can interrupt 16 percent of the peak demand, that is about 20 or 24 percent, I have forgotten, of the shoulder demand. And the red here shows the tremendous increases in prices when it is just a one-sided market without the opportunity for the wholesale buyers to strategically bid into that market and interrupt a portion of their demand and an attempt to keep prices down. Blue shows four different experiments where wholesale buyers are actively bidding in their own interests, and you will notice that those prices are far lower. Also, they spike a whole lot less. The energy spiking on peak is coming from generators bidding into a market with a completely inflexible demand. And all over the world, you see those spikes.

Now what is to be done? Well, my view is that you need to open up that portion of the grid below the substation level for innovation and competition. That means people attempting to make money by introducing technologies that are saving to give customers a break on their peak charges, and also, of course, there are possibilities for distributed generation to be installed closer to the customer and to bypass the entire grid and get below the substation level. And I think the—that means allowing alternative energy suppliers to come in and sell energy to the customers of the local wires company. That means the inference have to get access to the wires in order to install the technologies that their customers prefer. The local wires company is not well motivated to let people in there. Madame Chairman, you, perhaps, remember when you bought a new telephone for your home, you had to buy it from the American Telephone and Telegraph Company. You were not allowed to buy a telephone separately and install it in your house. And furthermore, Ma Bell, at the time, gave you a choice. When things really opened up, you got your choice between black, white, and red. All right. All of that has changed.

The other thing that you couldn't do under the government-sanctioned monopoly of AT&T is let anyone in your house, any repairman in your house to fiddle with the telephone wires. That person had to come in an AT&T truck. All of that has changed. Arguments were made at the time. We can not let people in there to fiddle with the wires, because it is the integrity and security of the bid we are worrying about. Not any—I mean, you know, that is real complicated that red, green, and yellow wire in there, and it has to be handled by AT&T. That is the situation we face in the local distribution utilities. And I think until that is opened up, we are going to continue to have problems.

Thank you.

[The prepared statement of Dr. Smith follows:]

PREPARED STATEMENT OF VERNON L. SMITH

Testimony will address the following four questions:

1) Briefly describe the market structure for the electricity sector as it existed 15 years ago and contrast it with the structure today.
2) What barriers currently prevent wider adoption of commercially available energy technologies? What policy choices would be most conducive to greater adoption of these technologies?
3) How is uncertainly affecting the economics of investment in the electricity sector? How can we structure a market to ensure reliable electricity at the lowest cost?
4) What are the incentives for utilities to invest in transmission research and development? How can we encourage investment in research and development in a highly competitive electricity sector?

Responses:

Q1: The market structure at the retail level, which is where the system is rigid and unresponsive, has not changed in 15 years. Essentially from the neighborhood substation to the end use customer, we are talking about 1930's technology. Two slides:

Slide 1; Variability of wholesale energy cost during a hot August week in the Midwest (1980s), showing the effect of a fixed energy retail price: *Customers pay less than the cost of their energy consumed on peak, and the loss to the utility is therefore a subsidy that encourages consumption; customers pay more than the cost of their energy off peak, and are therefore taxed to discourage consumption.*

Slide 2; Effect of profit-motivated human subjects who bid their demand in to the spot market along with supply-side bids by generation firms who have market power on the shoulder demand periods. Sixteen percent of peak (20 percent of shoulder) demand is interruptible. *Market power is neutralized by the wholesale demand side buyers; price spikes all but disappear; and prices are much lower, more nearly reflecting the dynamic changes in wholesale costs.*

Q2: The barriers are the continuation of 85 years of regulation of the local distribution franchised monopoly preventing free entry by alternative suppliers of ENERGY. Regulation protects the right of the local distributor to tie the sale of energy into the rental of the wires.

It's like legally franchising the right of the rental car companies to require their customers to buy all their gasoline from the rental car company's own supplies. But of course the technologies required are very different in electricity.

Two suggested policies:

1. Permit free entry by qualified energy suppliers; over time phase out energy sales by the local wires companies.
2. Allow entrants access to the wires between the end user outlet, and the substation to install technologies that fit consumer preferences, and allow interruption of peak time energy deliveries when its cost is more than individual customers want to pay. Similarly, entrants can compete to provide customers off peak discounts.

Q3: At the retail level no one knows what menu of dynamic pricing contracts and corresponding technologies will fit individual consumer circumstances, and emerge as profitable for retail energy suppliers. Moreover, no one knows what new lower cost technologies will emerge once there is an incentive for firms to innovate between the substation and the end use consumer. *This is normal market investment uncertainty.* The structure needed to deal with that uncertainty is indicated in the two policies recommended in Q2.

Q4: The first order of business is not at the transmission level. Transmission is strained and stressed by inflexible peak consumption tending to exceed energy supplies. Transmission capacity is entirely determined by peak requirements, but at the consumption level there is neither the technology nor the competitive incentive to implement a dynamic price responsive demand that limits peak consumption, and reduces peak transmission requirements. More expensive transmission capacity could easily do more harm than good by casting in concrete the downstream rigid retail incentive demand structure.

The retail energy supply sector is not now close to being highly competitive. When it is, the supplying firms will have all the incentive they need to innovate and profit thereby.

Demand, Not Supply

Wall Street Journal

BY VERNON L. SMITH AND LYNNE KIESLING

Immediately following the failure of the electrical network from Ohio to the Northeast Coast, a cascade of rhetoric swept across news networks, blaming the blackout on an antiquated grid with inadequate capacity to carry growing demand for electrical energy. As in the California energy debacle, we are hearing the familiar call on government to "do something."

The California government response—doing something—left the state with a staggering and unnecessary level of debt. Meanwhile, without any additional action by the state, the demand and energy supplies in California have returned to their normal and much less stressful levels and wholesale prices are back to normal. There is no news except good news, but have we gained any deep understanding of power system vulnerability and its efficient cure from this event?

Before Congress and the administration begins to follow the California model and throw other people's money at the power industry, let's have some sober and less frantic talk.

A systematic rethinking of the power demand and supply system—not just transmissions lines—is required to bring the energy industry into the contemporary age. Eighty-five years of regulatory efforts have focused exclusively on supply—leaving on dusty shelves proposals to empower consumer demand, to help stabilize electric systems while creating a more flexible economic environment.

Under these regulations, a pricing system has developed that is so badly structured at the critical retail level that if it were replicated throughout the economy, we would all be as poor as the proverbial church mouse. Retail customers pay averaged rates, making their demand unresponsive to changes in supply cost. Without dynamic retail pricing, no one can determine whether, when, where or how to invest in energy infrastructure. Impulsive proposals to incentivize transmission investment, without retail demand response, puts the cart before the horse and risks expensive and unnecessary investment decisions, costly to reverse.

At the end-use customer level, the demand for energy is almost completely unresponsive to the hourly, daily and seasonal variation in the cost of getting energy from its source—over transmission lines, through the substations and to the outlet plugs. The capacity of every component of that system is determined by the peak demand it must meet. Yet that system has been saddled with a pure fantasy regulatory requirement that every link in that system at all times be adequate to meet all demand. Moreover, the industry has been regulated by average return criteria, and average pricing.

When the inevitable occurs, as in California, and unresponsive demand exceeds supply, demand must be cut off. Your local utility sheds load by switching off entire substations—darkening entire regions—because the utility has no way to prioritize and price the more valuable uses of power below that relic of 1930s electronic technology. This is why people get stuck in elevators and high-value uses of power are shut off along with all the lowest priority uses of energy. It's the meat-ax approach to interrupting power flows. Between the substation and the end-use consumer appliance is a business and technology no-mans-land ripe for innovation.

When a transmission line is stressed to capacity, and its congestion cost spikes upward, the market is signaling the need for increased capacity in any of three components of the delivery system: increased investment in technologies for achieving price responsive demand at end use appliances; increased generation nearer to the consumer on the delivery end of the line; or increased investment in transmission capacity.

What is inadequately discussed, let alone motivated, is the first option—demand response.

Many technologies are available that provide a dual benefit—empowering consumers to control both energy costs and usage while also stabilizing the national energy system. The simplest and cheapest is a signal controlled switch installed on an electrical appliance, such as an air conditioner, coupled with a contract that pays the customer for the right to cut off the appliance for specified limited periods during peak consumption times of the day. Another relatively inexpensive option is to install a second, watt-hour meter that measures nighttime consumption, when energy usage is low, coupled with a day rate and a cheaper night rate. More costly is a time-of-use meter that measures consumption in intervals over all hours of the day, and the price is varied with delivery cost throughout the day. Finally, a load management system unit can be installed in your house or business that programs appliances on or off depending on price, according to consumer preferences.

More important, better and cheaper technologies will be invented once retail energy is subject to free entry and exit. No one knows what combination of technology, cost and consumer preferences will be selected. And that is why the process must be exposed to the trial-and-error experiment called free entry, exit and pricing. As in other industries, investors will risk their own capital—not your tax dollars or a charge on your utility bill—for investments that fail. Also, as in other industries with dynamically changing product demand, competition will force prices to be slashed off-peak, and increased on-peak to better utilize capacity.

Together with demand response technologies, a simple regulatory fix can give new entrants the incentive to provide customers with attractive retail demand options. Local regulated distribution utilities have always had the legally and jealously protected right to tie in the rental of the wires with the sale of the energy delivered over those wires. But these are distinctly separable activities. Just as rental car companies are separate from gas stations, electricity can be purchased separately from the company that delivers it to you—provided only that they can access the wires to install metering, monitoring and switching devices that fit the budget/preferences of individual consumers.

Remember when Ma Bell would not let you buy any telephone but hers, and would not let you admit any licensed electrician into your house to access the telephone wires except those arriving in her service truck? All that has changed for the better in telecommunications, but we are still stuck in a noncompetitive world in the local utility industry.

* * *

Against the backdrop of the wars in Iraq and Afghanistan, the East Coast blackout stimulated déjà vu speculation of Sept. 11 and fears of shadowy operatives bent on disaster. Since 2002, the Critical Infrastructure Protection Project at George Mason University has worked under a Department of Commerce grant to integrate the study of law, technology, policy and economics relating to the vulnerability of key U.S. infrastructure. Prime among this continuing research is investigation of the susceptibility of the national power grid.

As it turns out, terrorist speculation, though false, did not fall far from the truth. If you were to design an electrical system maximizing vulnerability to attack, it is hard to imagine a better design than what has evolved in response to regulation. If a terrorist attack took out half the energy supply to Chicago, the only viable response would be to shut down half the substations. Demand response would allow a prioritization of energy use, shutting down only the lowest priority of power consumption while supplying high value uses—such as production facilities, computer networks, ports, airports and elevators. Power systems badly need the flexibility to selectively interrupt lowest value uses of power while continuing to serve higher value uses. Retail price responsiveness in a competitive environment provides such a priority system.

The implementation of retail demand response in the electric power industry would provide a wide range of benefits including lower capital and energy costs, fewer critical power spikes, consumer control over electricity prices, and the environmental benefits gained by empowering consumers to use electricity more wisely. Despite Milton Friedman's admonition, by adding increased flexibility to the electricity grid and sparing critical infrastructure from shutdown, demand response creates a more efficient and resilient economic structure while providing more robust security as a free lunch.

Mr. Smith, on leave at the University of Alaska Anchorage, is professor of economics and law at George Mason and the 2002 Nobel laureate in economics. Ms. Kiesling is senior lecturer in economics at Northwestern and director of economic policy at the Reason Foundation.

Updated August 20, 2003

BIOGRAPHY FOR VERNON L. SMITH

Vernon L. Smith was born in the flat plains of Wichita, Kansas during the boom years preceding the Great Depression, January 1, 1927. Born to politically active parents—and an avowedly Socialist mother who revered Eugene Debs—Vernon Smith's early ideological indoctrination would prove pivotal to his attraction to the economic sciences.

While earning his bachelor's degree in electrical engineering at the California Institute of Technology in 1949 Smith took a general economics course. Intrigued, Smith pursued the science, receiving a Masters in Economics from the University of Kansas in 1952 and a Ph.D. from Harvard University in 1955.

Dr. Smith's initial training in the hard sciences lead him to pursue the application of the scientific method in his chosen profession, and social science, of economics. Predisposed to have the heart of a socialist, Dr. Smith expected to prove the inefficiencies of market mechanisms when he conducted his first economic experiments in 1956 at Purdue University, using his students as subjects. However, Dr. Smith's experiments—testing economic concepts and theories under controlled conditions—instead overwhelmingly demonstrated to him the clear efficiencies of markets. Smith found that even with very little information and a modest number of participants, subjects converge rapidly to create a competitive equilibrium.

Specifically, Smith's experiments proved large numbers of perfectly informed economic agents were not prerequisites for market efficiency—a radical departure from conventional economic thought. Smith compiled his early experiments and in 1962, while a Visiting Professor at Stanford University, published his findings in the *Journal of Political Economy.* The article, "An Experimental Study of Market Behavior," is today considered the landmark paper on experimental economics.

Continuing his work, again at Purdue University, Smith conducted more and more experiments while also becoming well known as an expert in capital theory formation and an early pioneer in the field of environmental economics. Widening the interest in academia, Smith continued to research and teach experimental methods, as well as explore new avenues, at Brown University, University of Massachusetts, University of Southern California, California Institute of Technology and the University of Arizona.

Displaying an unusual breadth of academic understanding and application, Smith has published and co-published numerous seminal works exploring, and defining, experimental economics as well as other economic disciplines. His "The Principle of Unanimity and Voluntary Consent in Social Choice" published in the *Journal of Political Economy* in 1977 initiated the systematic study of institutional design for public choice decisions. The 1982 "Microeconomic Systems as an Experimental Science" in the *American Economic Review* marked the still adhered to methodology for experimental economics. His 1982 "A Combinatorial Auction Mechanism for Airport Time Slot Allocation" in the *Bell Journal of Economics* provided a real-world application of experimental economics on economic systems design. The 1988 "Bubbles, Crashes and Endogenous Expectations in Experimental Spot Asset Markets" published in *Econometrica* examined stock market bubbles and rational expectations. The 1994 "Preferences, Property Rights and Anonymity in Bargaining Games" in *Games and Economic Behavior* started the systematic study of personal exchange.

At the same time the slow but steady development in experimental economics begun by Smith in the 1950s and 1960s was superseded by accelerated development in the 1970s and 1980s. After establishing himself as the field's pre-eminent researcher, Smith collaborated with several noted economists to refine and improve his subject.

From Smith's foundation of research, the modern experimental methods in economics began to gain acceptance. The research expanded to include the economic performance of many real-world institutions. Attempts to apply laboratory experimental methods to policy problems became systematic. The convergence properties of multiple markets were discovered. Conspiracy, price controls and other types of market interventions were examined experimentally for the first time. New forms of markets were studied, such as methods for deciding on programs for public broadcasting. All this research stems from the initial contributions of Dr. Vernon Smith.

Current research is focused on the design and testing of markets for electric power, water and spectrum licenses and a new field 'neuroeconomics' which analyzes the impact of brain functions on economic decision-making. As well, Dr. Smith and his colleagues have worked with the Australian and New Zealand governments on privatization issues, developed market designs for the Arizona stock exchange, and designed an electronic market for water in California.

Dr. Smith's groundbreaking work has led to an explosion in the application of laboratory experimental methods. Volumes of experimental papers are being published each year and the number of experimental laboratories are growing rapidly around the world. ICES is now the preeminent facility serving as a model for experimental economic and laboratory development throughout the world.

On December 10, 2002 Dr. Smith received the *Bank of Sweden Prize in Economic Sciences in Memory of Alfred Nobel*—the Nobel Prize in Economics—from His Majesty Carl XVI Gustaf for "for having established laboratory experiments as a tool in empirical economic analysis, especially in the study of alternative market mechanisms."

Chairwoman BIGGERT. Thank you very much. I certainly do remember those phones. I think we had to lease them, too, and then finally you could purchase them. I hate to admit it, but I do remember.

Mr. Casten, if you would like to begin.

STATEMENT OF MR. THOMAS R. CASTEN, CEO, PRIVATE POWER, LLC, OAK BROOK, IL; CHAIRMAN, WORLD ALLIANCE FOR DECENTRALIZED ENERGY

Mr. CASTEN. Madame Chairwoman, Members of Congress, thank you for the opportunity to present my views on preventing blackouts while saving money and reducing pollution.

We have the technology to greatly improve the U.S. power system. Building local power that recycles presently wasted energy will reduce system vulnerability, reduce future capital expenditures for power, reduce energy costs/pollution, greenhouse gas emissions, and significantly improve the economy. What is not to like?

But all of the technologies that generate power locally and thus lower the throughput on existing wires are discouraged and, indeed, stopped by many barriers. We have heard much about an industry vision of a smart and self-healing grid. And I think those are welcome changes, but that view focuses on modernizing the grid, and it falls short on modernizing the world view that continues to treat central generation as optimal. Pursuing this obsolete central generation vision will lead to more wires we don't need, will raise the cost of power to consumers, and will only modestly lessen system vulnerability.

Finally, I would like to note that Isabel was the ninth area-wide blackout in the last seven years, which is still going on. The only unique thing about the blackout in question is that it was not attributed to an act of God. And so we are—we can chase some culpable individual, but in the western states, a tree branch knocked out 18 states six years ago and on and on.

Now on background, responding to your questions. I have been attempting to change the way the world makes power for 25 years, believing that we can no longer afford the waste inherent in remote generation. The U.S. power system reached the pinnacle of its efficiency in 1959 when it converted 33 percent of the fuel that it burned into delivered energy. It has not increased one percentage point in the ensuing four decades, despite of all of the technology.

I founded Trigen Energy Corporation, ultimately taking it public on the New York Stock Exchange, to correct this. The 56 power plants that we built used a variety of fuels: biomass, coal, oil, natural gas, and waste fuels. They ranged from a single megawatt to over 200 megawatts. In total, we made more power than the single largest nuclear plant in the United States, all locally. Each of these plants recycled the normally wasted heat. Operating in 18 states, including Pennsylvania, Georgia, Michigan, Tennessee, and Indiana, we achieved our mission of producing heating, cooling, and electricity with less than half the fossil fuel and less than half the pollution of conventional generation. If the system was anywhere near optimal, it would not be possible to achieve those kind of results.

After an unwelcome buyout of Trigen, I joined with others to form Private Power to purchase and operate projects that recycle energy. We recently announced agreement to acquire six projects in northern Indiana. They are within an hour's drive of Hinsdale, Madame Chairman, and I would be delighted to—and honored to have you and your staff visit those projects. And I think it would be useful.

We generate 460 megawatts of power with virtually no fossil fuel. One of the projects recovers heat from 368 coke ovens, uses utility style technology to convert that into 100 megawatts of power and 200,000 pounds of steam. And all of that power stays right at the steel mill. Three of the projects burn blast furnace gas that had been flared and create another 300 megawatts of power. One conventional project burns gas in a gas turbine, but achieves 2½ times the efficiency of central power, because we take all of the heat and use it for the cold rolling process at the steel mill.

The projects have won several environmental awards. They significantly reduce greenhouse gases, and they save the four steel companies over $100 billion a year. Moreover, today's concern about blackouts and system vulnerability, these projects ease the transmission loads and reduce line losses to other customers. All of the power stays home, is used by the steel mills, and in times of high system demand, these projects automatically adjust their output to support the voltage on the back end of the lines, and that allows the wires to carry more power with fewer losses to other consumers.

We have analyzed the data that EPA keeps of flare gas, of heat exhausted from industrial processes and of pressure drop that is ignored by our central power system. We find that this waste energy in the United States, if recycled, could produce between 45,000 and 90,000 megawatts of fossil fuel-free, pollution-free power. That is the equivalent of 90 nuclear plants with no environmental problems. Another 300 gigawatts, which would be about half of the U.S. power demand, and all of the projected 20-year load growth could be generated by burning fuel locally where you could take the normally wasted heat and recycle it to avoid putting more fuel into a boiler.

In summary, local power has these benefits. It does not need transmission wires. It is thus cheaper to construct. It avoids the nine percent average line losses. It recycles waste heat inherent in all power generation. Or even better, it uses industrial waste heat to generate the power. EPA just completed a study that combined heat and power emits 1/20 of the pollution of the average central power station. We have estimated that the $390 billion U.S. heat and power system could slash $100 billion a year out of its costs by deploying local power.

You asked what the barriers are to local power, and I will be quick about them. I have summarized them later. It is illegal to run a private wire across the street in all 50 states. Rate commissions allow their utilities to charge for 100 percent of the wires and generation for backup, even though on an actual basis, it is about two percent. It is like charging $100 for $100 of life insurance. There is no locational value given in where the power is located. In Texas, it costs the same to move power across the street as the whole way across the state, discouraging the local power. There are all of the policy decisions, I am sad to say, including this committee, use the wrong metric. You talk about what is the cost of the power at the generator. What is the capital cost of the generator? It is an irrelevant question. What is the cost at the consumer after you pay for the wires? Local power doesn't need wires. The environmental policy does not recognize the output and therefore gives no encouragement to recycling energy.

What are the policy choices that you could follow to encourage local power? I think most important, use the right metric and talk about the real thing: what does it cost at the consumer? Secondly, I think Congress should remove the ban on private wires. This would give all local power developers a fair chance to get a reasonable price on using existing wires to move their power. There wouldn't be any new wires built, but we would have a fair discussion. You need to demand standard interconnection rules without the excessive and bogus safety concerns of the red and green wires that Dr. Smith refers to. I think you should encourage or demand recycled power. I would strongly support a clean portfolio standard that mandates that a growing percentage of power come from recycled energy, and that will encourage local power. That is where it all is. And finally, I would suggest that you have the national laboratories shift their focus from new generation technology to focusing on the interconnection issues and getting deployment of the technologies that are already there.

Finally, you asked what the local deployment differences are. The U.S. generates only six percent of its total power locally, all of the rest coming from remote plants. By contrast, Denmark, Finland, and the Netherlands generate over 40 percent of their power out of local plants, saving wires and making it cheaper. Within the U.S., the picture is equally diverse. Three states, South Carolina, South Dakota, and Kentucky, have virtually no local generation. At the other extreme, Hawaii produces 33 percent. California, I think, is about 25 percent local power. New York and Maine are in the high teens. The differences are in State encouragement of wider choices.

The high local power states encourage local power with requirements for utilities to purchase the power at full cost. They tackled interconnection rules. They tailored their environmental management to output standards and rewarded efficiency. And they have provided grants to break old paradigms. The states with little local power have laws preventing third parties from generating power on site and selling it. They give no locational value to power.

In conclusion, I note that Congress faces a seemingly unpleasant task. The power industry begs help to build more wires. The papers are asking for $100 billion for improved grid and wires. They ask for new eminent domain rights so that the wires can slash across our parks and backyard. I think this will raise prices. It will annoy the voters, and it will largely fail to address system vulnerability or to mitigate power system related problems. There is a better solution. Local generation operation options are technically right. They are environmentally superior. They are at least twice as efficient as the average central generation. My work in Trigen and now Private Power has proven the value of these systems. I think that if Congress lifts the many barriers, everyone will follow.

Thank you.

[The prepared statement of Mr. Casten follows:]

PREPARED STATEMENT OF THOMAS R. CASTEN

Madam Chairwoman, Congresspersons, Ladies & Gentlemen:

My name is Tom Casten and I am the Chairman and CEO of Private Power in Oak Brook, Illinois. I appreciate the opportunity to present my views on preventing blackouts while saving money and reducing pollution. We have the technology, but block its use because of a now obsolete worldview. We have heard much about an "industry consensus vision" for a smart, self-healing grid. This view focuses on modernizing the grid, but falls short on modernizing the worldview and leads to more wires we don't need. Applying three (3) simple principals will optimize the power system. The principals are:

- Build local power
- Build smaller
- Recycle waste energy.

Blackouts blackouts everywhere

On August 14th, around 2:00 PM, a 31-year-old, 650 megawatt Ohio power station failed. Transmission controllers struggled to route power from remote plants, overloading transmission lines. At 4:06, a 1200-megawatt transmission line melted, starting a failure cascade. Lacking local generation, system operators could not maintain voltage and five nuclear plants tripped, forcing power to flow from more remote plants and overloaded regional lines. By 4:16 PM, the northeastern U.S. and Ontario, Canada lost power.

Before the even more recent blackouts associated with Hurricane Isabelle that many of you have experienced, the August 14th blackout was the eighth area-wide loss of power in seven years. It differed from the prior seven blackouts in one respect—the cause was not seen as an act of God. Herewith the recent record:

1996— A falling tree branch in Idaho led to a failure cascade, blacking out 18 states.

1997— An ice storm in Quebec downed transmission lines and blacked out much of New England.

June 1998— A tornado downed a Wisconsin power line leading to rolling brownouts east of Mississippi.

2000— Low water and a failed nuclear plant caused a power crisis in California with a month of brownouts and rolling blackouts. This nearly bankrupted California.

1999–2002— Three separate ice storms caused large area blackouts in Oklahoma.

2003— A thirty-one year old coal plant in Ohio tripped. Lines overloaded as power moved from further away, voltage dropped, dramatically reducing the capacity of transmission lines and 50 million people lost power.

A review of electric generation history

For electricity's first 100 years, the optimal way to produce and deliver power was with large, remote central stations feeding long wires; this formed a deep, central generation bias. Initially all power came from two central technologies—hydro and coal fired steam plants. Hydroelectric plants were inherently remote and early coal plants were noisy and dirty—not good neighbors. Also coal plants required skilled operators, making them inappropriate for smaller users. For 80 years, power from remote plants—linked to the user by an ever-growing set of wires—enjoyed cost advantages over local power. Nuclear power technology, commercialized in the 1960's, was also seen as inherently remote by everyone but Admiral Rickover and the U.S. Navy.

Everyone assumed that central generation was and would always be technically and economically optimal. Many laws and regulations reinforced this assumption. If all generation is central, then all power must flow through wires, which seemed to be a natural monopoly. Laws enshrined a monopoly approach, with good results. The country was rapidly electrified and power prices feel from $4.00/kWh in 1900 to 5.8 cents/kWh in 1968. The electric age celebrated its 88th birthday. Technology was changing but local power technologies were blocked.

The monopoly approach created an incredibly strong power industry with deeply vested interests in all power flowing through their wires, and once central technologies matured, progress stopped. Between 1969 and 1984 power prices rose 65 percent. After 1959, delivered average efficiency never improved beyond 33 percent. But things changed. People came to hate the ugly fifth column of transmission lines. We learned more about the bad side effects of burning fossil fuel and as population grew, electricity demand grew with it. Fossil fuel imports also grew, unbalancing the budget. Then 9/11 terrorist attacks focused attention on infrastructure vulnerability.

These issues must inform the discussions about preventing blackouts. Fortunately, we have the technology to simultaneously address all problems if we change the central generation paradigm:

1. Build local power
2. Build smaller
3. Recycle waste energy.

Distributed generation comes of age

Technical progress has provided many local power answers. It employs proven central generation technologies and fuels but is located next to electric and thermal loads. DG power goes directly to users, bypassing transmission, and DG plants recycle normally wasted heat, saving fuel and pollution. Local generation options are technically ripe, environmentally superior, and at least twice as efficient as average central generation. In fact, much of the technical progress has occurred as a result of government supported research.

But do not limit focus to sexy new technologies like micro turbines, solar photovoltaic or fuel cells. There are many proven local power technologies, matched to all medium to large electric loads.

Economics of scale have been reversed by the microcomputer. Small steam turbines, able to extract power from local energy waste were available in 1950 but required operators, making most on-site generation less economic than central power. Today, microcomputer controls enable steam turbines to operate unattended and produce economic local power.

Modern gas turbines are clean and compact, unobtrusive neighbors. Two 5MW gas turbines now generate power at the steam plant serving the White House, the DOE and the EPA, and they are more than twice as efficient as central plants because they recycle wasted heat. Their power needs no transmission wires. It stays home.

The most efficient gas turbine yet built is a 50 megawatts LM6000GE, matched to middle sized industrial complexes or large universities. The next best turbine in the world is 4 megawatt solar mercury turbine, perfect for hospitals and small industry.

An even better local power opportunity burns no new fuel. The U.S. flares waste gas, vents waste process heat and fails to harness steam pressure drop that could support 45 to 90 gigawatts of local, fuel-free, pollution free, wire-free power—over 10 percent of U.S. load. Only 1 to 2 gigawatts of this waste energy is currently recycled. The needed technology is available, proven, and less expensive than central plants and wires.

The U.S. is out of transmission capacity and electric peak load is projected to grow by 43 percent over 20 years—300 gigawatts. Line losses have grown from 5 percent in 1960 to 9 percent in 2002 and exceed 20 percent on peak. If we stay with the central generation paradigm, we must build 375 GW of large new plants to accommodate peak line loses. By contrast, 300 GW of local power will meet peak load with no new wires and no added line loses. And, because local plants can recycle waste heat, we will burn only half the fuel.

The technology is here today but it is the outmoded laws, regulations and the vested interests in central power that keep deployment at bay.

As I have said, the optimal approach is to:

1. Build local power

2. Build smaller
3. Recycle waste energy.

How can Congress find solutions?

This Congress faces a seemingly unpleasant task. The power industry begs help to build more wires—$100 billion of new wires and an improved grid. They ask for new federal eminent domain rights to enable new wires to slash through forests and backyards. This will raise prices, annoy voters, and largely fail to address system vulnerability or to mitigate power system related problems.

There is a better approach:

1. Demand and use the right metric in all discussions. What is the delivered cost of power? Stop focusing on capital cost and the cost per kWh at the generator—count the line costs and line losses and extra capital for peak loads. Recognize the locational value of power.
2. Remove regulatory barriers to local power. Instead of new federal eminent domain for transmission wires, overturn the 50 state bans on private wires. Give distributed generation operators the right to bypass the wires monopoly and deliver their power across the street, just as federal laws allow private gas pipes. Few private pipes are built and few private wires will be built, but lifting bans on private wires will transform the power industry, ending the ability of monopolies to block local power with excessive line charges. Couple this right with standardized interconnection access, the right to backup power and an environmental regulatory framework that recognizes the environmental benefits of the combined production of power and heat (CHP).
3. Encourage and/or demand recycled power development. Pass a clean portfolio standard that requires a growing percentage of power from renewables and recycled energy. Give manufacturers a reason to recycle waste fuel, waste heat and pressure drop.
4. The work of the national laboratories has pushed the frontier of technology but with efforts often conducted in isolation of broader national needs. There is a need to assess and refute the still widespread belief that distributed generation can not be safely integrated into the electric distribution system at reasonable costs. Every effort should be made to showcase and highlight the many existing commercial technologies that DOE and others have had a role in developing which can safely and cost effectively integrate DG into the grid.

This is a short summary of an analysis showing that the optimal way to meet future electric load growth is with distributed generation—using proven technology DG. I have attached a more comprehensive analysis in the form of a paper entitled "Preventing Blackouts."

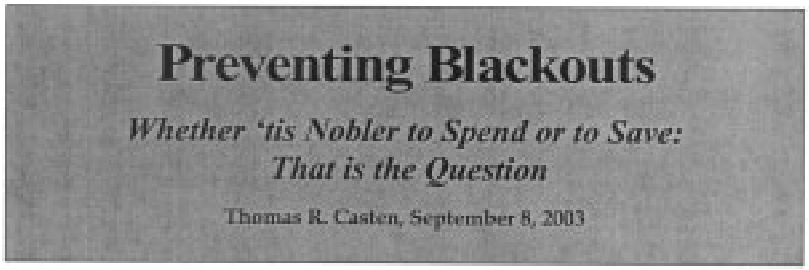
In closing, let me reiterate how to prevent more blackouts while saving money and reducing pollution:

1. Build local power
2. Build smaller
3. Recycle waste energy.

BIOGRAPHY FOR THOMAS R. CASTEN

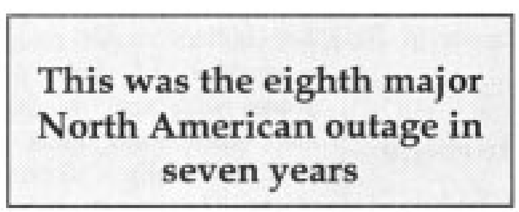
Thomas R. Casten has spent over 25 years developing and operating combined heat and power plants as a way to save money, increase efficiency and lower emissions. A leading advocate of clean and efficient power production, Mr. Casten is the founding Chairman and CEO of Private Power LLC, an independent power company in Oak Brook, IL, which focuses on developing power plants that utilize waste heat and waste fuel. In 1986 he founded Trigen Energy Corporation and served as its President and CEO until 1999. Trigen's mission reflects that of its founder: to produce electricity, heat, and cooling with one-half the fossil fuel and one-half the pollution of conventional generation.

Mr. Casten has served as President of the International District Energy Association and has received the Norman R. Taylor Award for distinguished achievement and contributions to the industry. He currently serves on the board of the American Council for an Energy-Efficient Economy (ACEEE), the board of the Center for Inquiry, and the Fuel Cell Energy Board. He is the Chairman of the World Alliance for Decentralized Energy (WADE), an alliance of national and regional combined heat and power associations, wind, photovoltaic and biomass organizations and various foundations and government agencies seeking to mitigate climate change by increasing the fossil efficiency of heat and power generation. Tom's book, *"Turning Off The Heat,"* published by Prometheus Press in 1998, explains how the U.S. can save money and pollution.



New York City, Early Evening, August 14, 2003

On August 14th, around 2:00 PM, a 31-year-old, 650 megawatt Ohio power station failed. Transmission controllers struggled to route power from remote plants, overloading transmission lines. At 4:06, a 1200-megawatt transmission line melted, starting a failure cascade. Lacking local generation, system operators could not maintain voltage and five nuclear plants tripped, forcing power to flow from more remote plants and overloaded regional lines. By 4:16 PM, the northeastern U.S. and Ontario, Canada lost power.



This was the eighth major North American outage in seven years, not counting five localized blackouts in New York City and Chicago. These area wide failures began in 1996 with a blackout of 18 western states, followed by a 1997 ice storm in Quebec that knocked out much of New England, a 1998 tornado that crippled midwestern power systems, California system failure in 2000, three ice storms in Oklahoma and the August 2003 blackout. Pundits spread blame widely and call for massive investment in wires, while ignoring the fundamental flaw—*excessive reliance on central generation of electricity.*

Power system problems are deeper than repeated transmission failures. Average U.S. generating plants are old (average age 35 years), wasteful (33 percent delivered efficiency) and dirty (50 times the pollution of the best new distributed generation). Centralized generation, besides requiring ugly, highly visible transmission lines, does not recycle its own byproduct heat or extract fuel-free power from industrial waste heat and waste energy. This leaves two starkly contrasting ways to address blackouts:

- Spend billions on new wires. This will not completely eliminate blackouts and will exacerbate other problems.
- Save money by encouraging distributed generation. This will greatly reduce system vulnerability and deliver a host of other benefits.

Distributed generation (DG) has come of age. It employs proven central generation technologies and fuels but is located next to electric and thermal loads. DG power goes directly to users, bypassing transmission, and DG plants recycle normally wasted heat, saving fuel and pollution. Local generation options are technically ripe, environmentally superior, and at least twice as efficient as average central generation.

Unfortunately, laws and regulations block distributed generation. The industry and its regulators are caught in an overloaded, wire-entangled web that blocks innovation.

The Wiring of America

Central generation—long considered optimal—is an outgrowth of early generating technologies. Hydroelectric plants were inherently remote and early coal plants were noisy and dirty—not good neighbors. And coal plants required skilled operators, making them inappropriate for smaller users. For 80 years, power from remote plants—linked to the user by an ever-growing set of wires—enjoyed cost advantages over local power.

By contrast, transportation required small engines that did not need skilled operators. Coal was tried for automobiles (the Stanley Steamer), but soon displaced by oil fired piston engines. For the first six decades of the 20th century, power technology evolved along two separate paths—coal fired steam turbines for electricity and oil fueled piston engines for transportation.

Over time, engine-driven power plants became cheaper to build, but required more expensive fuel and were only economic for backup or remote electric generation. Coal fired steam power remained a better value for electricity into the 1960 period.

Aircraft needs spurred another power generation technology, the combustion turbine. Pioneered near the end of WWII, early combustion turbines lacked efficiency but produced more power per pound than engines—critical to aircraft. Technology marched on. By the early 1980's, combined cycle gas turbine plants had become more efficient than the best steam power plants. To fill the gap left by environmental pressure on coal plants, turbine manufacturers developed turbines suitable for stationary power generation.

> **By 1980, local gas turbine generation cost less to install and operate, required less net fuel and produced fewer net emissions that the best possible remote gas turbine generation and associated wires**

By 1980, local gas turbine generation cost less to install and operate, required less net fuel and produced fewer net emissions that the best possible remote gas turbine generation and associated wires. Turbines are available from sub-megawatt to two hundred megawatt, appropriate for local loads; the plants are all automated, clean and quiet. Generating power locally avoids capital for transmission lines and eliminates transmission losses. Local power plants, unlike remote generation plants, can recycle byproduct heat, reducing net fuel use and cost. The power industry embraced turbine technology, but clung to central generation, missing opportunities to save money and pollution with distributed gas turbine generation.

Many other trends of the past thirty years also make distributed generation attractive. Turbine and piston engine power plant electric efficiency continues to increase. Transmission system losses of remotely generated power have increased from 5 percent to 9 percent, due to congestion. Computer controls enable unattended local generation based on waste gas and waste fuel. The most efficient generation technology ever invented, back pressure steam turbines, were historically limited by operator needs. With computer controls, these devices can economically extract power from waste heat, waste fuel, and steam pressure drop in virtually every large commercial and industrial facility. The U.S. currently vents or flares heat, low-grade byproduct fuel and steam pressure drop that could support 45 to 90 gigawatts of back pressure turbine generation capacity—6 to 13 percent of current U.S. peak load.[1]

Even coal-fired local power now beats the costs of power delivered from remote coal plants. Advances in fluid bed boilers enable on-site production of heat and power with coal, biomass and other solid fuels in environmentally friendly plants. The limestone beds chemically bond with sulfur as calcium sulfate and limit combustion temperatures, reducing NO_X formation. These clean coal plants, located near users, recycle heat to achieve 2.5 times the efficiency of remote coal plants.

Given all of these advances, an optimal power system would generate most power near load, using existing wires to shuttle excess power. Because electricity flows to the nearest connected users, regardless of the sales contract, locally generated power bypasses transmission lines.

Which brings us back to those long protected, overburdened, vulnerable, and *failing* wires that connect remote central plants to customers. Although the power industry finds itself waist deep in the big muddy, it clings to central generation. *Every stakeholder pays.* Power prices shot up by 65 percent from 1968 to 84, needless environmental damage continues, many major industry players have declared bank-

[1] Thomas R. Casten and Martin J. Collins, *Recycled Energy: An Untapped Resource,* April 19, 2002.

ruptcy or are close, banks are saddled with billions of non-performing loans to new central plants and blackouts have become a way of life.

Regulations and Industry Responses

Competition cleanses, discarding firms that cling to yesterday's technology. But the electric industry has long been sheltered from competition. *The electric industry's guiding signals have, since 1900, come from regulation rather than from markets.* All "deregulation" to date has left intact universal bans on private electric wires and many rules that penalize local power generation and protect the incumbent firms from cleansing competition. History sheds light on how and why utilities and regulators have enshrined central generation and largely continued to oppose local power generation.

> **Electricity is arguably the greatest invention of all time.**

Electricity, commercialized in 1880, is arguably the greatest invention of all time. But early developers faced a big problem, finding money for wires to transport electricity to users who didn't think they needed it. To manage the risk, developers asked city councils for five-year exclusive franchises.

Thousands of small electric companies sprang up; by 1900, there were 130 in Chicago alone. Greedy alderman sold votes to extend franchises. Samuel Insull conceived of (and got) an Illinois state granted monopoly in perpetuity. State monopolies spread.

States established regulatory commissions to approve capital investments and set rates that assured utilities fair returns on capital. Under rate-based regulation, investments in efficiency improvements increase the rate base, but all savings go to customers. This approach does not allow utilities to profit from increasing efficiency. This misalignment of interests eventually caused industry stagnation, but in the early years, utilities chased efficiency to compete with candles, oil lamps, muscle power and self-generation.

Banks cheerfully loaned money to monopoly-protected utilities fueling a race to grow and acquire other systems. Power entrepreneurs borrowed huge sums to gain control over vast areas of the country. In 1929, the bubble burst; demand for electricity sagged, and over leveraged trusts could not pay debt service. Utility bankruptcies deepened the Great Depression. Congress's response—the Public Utility Holding Company Act (PUHCA)—prevented utility amalgamation and assigned federal watchdogs to oversee finances. PUHCA blocked profit growth via acquisition or financial engineering. Profit-seeking utilities had two options: (1) sell more power and (2) invest more capital in the rate base.

Both strategies favored central generation over local power. Utilities sponsored research in electric appliances, motors and other novel uses of electricity that increased sales and provided significant public benefits. But they also fought local generation with every available means.

Electric distribution companies have an understandable bias against generation that bypasses their wires and cuts potential profits. Utility monopolies long made it "Job One" to preserve the monopoly. The electric industry sponsored "Ready Kilowatt" campaigns to win industry love and skillfully coached (and paid) governments at every level to block distributed generation.

For eight decades, central generation was the optimal technology. The regulatory approach delivered nationwide electrification and real prices fell by 98 percent. Electrification not only improved standard of living, but also played a strong role in positive social change.

Then, beginning in the late 1960's problems arose. Central generation ceased to be optimal, but the industry ignored local power innovations. Which brings us back to stakeholder costs.

The Good Times End

By 1960, as competition withered away, utilities began pursuing questionable strategies. With no way to recycle byproduct heat, fuel efficiency never moved beyond 33 percent. Utilities and their regulators rushed to convert many coal-fired power plants to oil, just in time for the OPEC embargo in 1973. Many utilities committed to build massive central plants that required up to ten years to construct, far beyond safe planning horizons. When rising prices induced conservation, electric load growth flattened and left the industry with massive overcapacity.

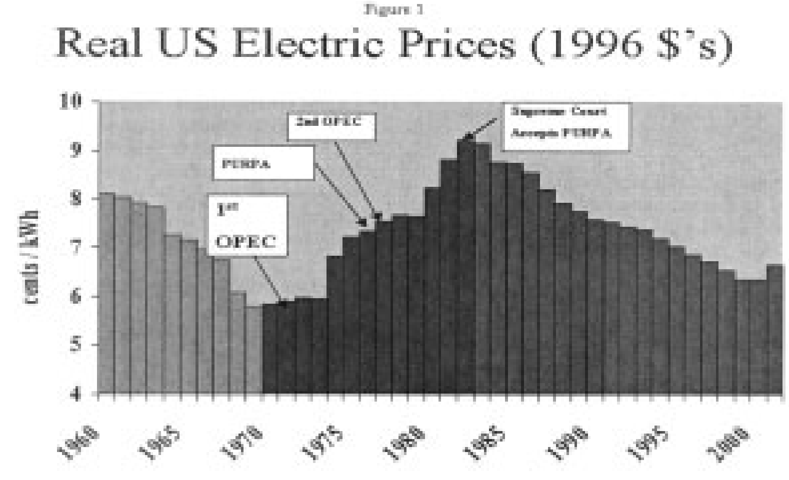
Then came nuclear. The utility industry committed vast sums, underestimating complexity and safety concerns. Some nukes were built near budget, but others broke the bank. Cost overruns of 300 percent to 500 percent were common. Long Island Lighting spent 19 years and $5 billion building Shoreham, only to have New York Governor Cuomo close the plant before it generated any power.

Figure 1 shows the rising real prices of U.S. electricity after 1968.[2] From 1970 to 1984, real electric prices rose 65 percent.

Regulatory responses nearly got it right, flirting with local generation. The 1978 Public Utility Regulatory Policy Act or PURPA sought to improve efficiency by exempting plants that recycled some heat from Federal Power Act regulations and required utilities to buy power from these plants at avoided costs. Utilities fought PURPA to the Supreme Court, losing in 1984. But subsequent changes removed the pressure to build plants near users, and nascent DG was again driven back.

Next came Three Mile Island. State commissions, fed up with nuclear cost overruns and rising prices, overturned the tacit regulatory compact. They challenged the prudence of utility investments in nuclear plants, claiming mismanagement. Historically friendly regulators ordered CEOs to remove billions of dollars from rate base and reduce electric prices. Utility shareholders took a bath.

Figure 1



The two changes did stop electric price inflation; prices dropped to 1969 levels by 2000. But utility managements went into shock. They curtailed in-system investments, but still needed to put massive cash flow to work. Smarting from independent power producers' (IPPs) "poaching" of their generation under PURPA, many utilities funded unregulated subsidiaries to "poach" generation in other territories. Never questioning the central generation mantra, utility subsidiaries began a disastrous race to build remote gas turbine plants, ignoring this strategy's vulnerability to rising gas prices. In thirteen months following May, 2001, the eleven largest merchant power plant builders destroyed over $200 billion of market capitalization. ENRON, NRG, and PSE&G and Mirant have since declared bankruptcy while, Dynegy, CMS and Mission struggle to pay creditors. Industry players that embraced gas-fired remote merchant plant development have seen their credit ratings lowered

[2] Prices given in 1996 dollars as reported at www.eia.doe.gov

to junk status. These mistakes have already cost a dozen utility CEOs their jobs, pounded utility shareholders and caused enormous bank losses.

Major transmission failures did not start immediately. Spare transmission capacity, built in the days of compliant regulation, absorbed load growth until 1996, when a falling tree set off an 18 state blackout throughout the west. By then, load growth had made the non-growing T&D system vulnerable to extreme weather (ice storms, tornadoes, hurricanes and drought induced hydro electric shortages), human error, and terrorists.

As costs and environmental concerns mounted, States began to experiment with partial deregulation, but never eased protection of wires, leaving utilities free to continue fighting DG by charging excessive backup rates and denying access to customers. Commissions allowed generators to sell to retail customers, but then set postage stamp transmission rates, charging the same to move power across the street or across Texas. DG power, which only moves across the street, was left to pay identical transmission rates to power moving hundreds of miles through expensive transmission wires. Wholesale power prices give little recognition to the locational value of generation.

Environmental regulations also suppress distributed generation. The 1976 Clean Air Act and subsequent amendments penalize efficiency. Almost all emission permits are granted based on fuel input, with no relationship to useful energy output. All new generation plants are required to install "best available control technology," while existing plants retain 'grandfather" rights to emit at historic levels. These grandfather rights give economic immortality to old central stations and block innovation, and thus bear some responsibility for system failures.

The costs to all stakeholders from the central generation worldview extend to other societal problems.

The costs to all stakeholders from the central generation world view extend to other societal problems. The balance of payments suffers from needless fuel imports. The U.S. demands for fossil fuel begat military adventures. Inefficient generation raises power costs, hurts industrial competitiveness and makes electric generation the major source of greenhouse gas emissions, threatening entire ecosystems.

An Exception Disproves the Rule

NIPSCO encouraged local power at the steel mills they serve in northern Indiana. Parent NiSource formed an unregulated subsidiary in 1994 that invested over $300 million in 460 megawatts of distributed power. Primary Energy built five projects that recycle waste heat and normally flared blast furnace gas. All of the power is consumed at the steel mills, easing transmission congestion and supporting local voltage.

The steel mills collectively save over $100 million per year by producing power with waste energy. These distributed generation projects produce no incremental emissions and displace the emissions of a medium sized coal fired station, 24/7. They are the environmental equivalent of roughly 2,500 megawatts of new solar collectors, which would only operate 20 percent of the time, on average.

These projects have not hurt NIPSCO, on balance. Yes, the utility sells less electricity to the mills, but steel production has risen, requiring more shifts and pumping up the local economy, increasing other electric sales. There is no reason why similar projects cannot be built to the benefit of all stakeholders in every other electric territory.

Whether 'tis Nobler to Spend or to Save; That is the Question

There are two distinct paths to avoid blackouts. Spend $50 to $100 billion on new and upgraded transmission lines or save money by removing barriers to distributed generation.

The first path will raise electric rates by 10 to 15 percent and will exacerbate other problems. The second path will cost taxpayers nothing and mitigate other problems.

To follow the second path, governments must:

- Allow anyone to sell backup power
- Enact standard and fair interconnect rules
- Void laws that ban third parties from selling power to their hosts.
- Give every power plant identical emission allowances per unit of useful energy.
- Recognize the locational value of generation.
- Most importantly, allow private wires to be built across public streets.

These changes will transform the $390 billion U.S. heat and power business into a dynamic marketplace of competing technologies and allow distributed generation's competitive advantages to prevail. Utilities and IPPs will build new DG capacity to serve expected electric load growth and reduce transmission congestion.

> **Ending central generation bias will upset vested interests and require a great deal of political effort, but the rewards for this leadership will be immense**

Ending central generation bias will upset vested interests and require a great deal of political effort, but the rewards for this leadership will be immense—lower power prices, reduced pollution, reduced greenhouse gas emissions, and a vastly less vulnerable national power system.

Thomas R. Casten has spent 25 years developing decentralized heat and power as founding President and CEO of Trigen Energy Corporation and its predecessors and currently as founding Chairman and CEO of Private Power LLC, an Illinois based firm specializing in recycling energy. Tom currently serves are Chairman of the World Alliance for Decentralized Energy (WADE), an alliance of national and regional combined heat and power associations, wind, photovoltaic and biomass organizations and various foundations and government agencies seeking to mitigate climate change by increasing the fossil efficiency of heat and power generation.

Tom's book, "Turning Off the Heat," published by Prometheus Press in 1998, explains how the U.S. can save money and pollution.

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DISCUSSION

Chairwoman BIGGERT. Thank you very much.

At this point, we will open our first round of questions. And the Chair recognizes herself for five minutes.

Mr. Glotfelty, your office is charged with improving the reliability of the electric system. And Dr. Smith has argued that the best way to encourage innovation and investment is to have a fully competitive market. Is there a conflict between innovation and reliability and between competition and reliability? And are you concerned that as we move toward a completely competitive market that there will be increased pressure to push the system beyond its limits? And then Mr. Casten suggests that there should be a—it would—it should be local and we should use waste energy. Has—is your committee looking—or commission looking into this, also?

Mr. GLOTFELTY. To address Dr. Smith's concern, we absolutely agree that demand response is a critical component to ensuring future reliability as is distributed resources. They are one of the components in a wide array of choices that we have to implement. I don't believe either one of them are the silver bullet to ensuring greater reliability or a greater and more efficient transmission system or electrical system, generally speaking, but they are two of the most critical components as we move forward that have to be addressed.

The problem, from our standpoint, is both of those issues are State issues. They deal with retail customers. At the federal level, we deal at the wholesale level. So there has been a conflict for many years that the Congress has grappled with when considering energy legislation as to do you violate the States' rights that deal with the retail customer and say demand response is a federal issue and therefore we promulgate these rules. And the same thing with distributed resources. It is a conflict that I think is apparent in the energy bill that is being considered today, but it can be resolved. And it should be resolved, because both provide a valuable component for a more efficient and reliable transmission system.

Chairwoman BIGGERT. As far as the recycling of waste energy, is this a possibility?

Mr. GLOTFELTY. Absolutely. Combined heat and power, in this Administration, going as far back as the President's National Energy Policy, we have said time and time again that we are believers in that. Combined heat and power is very efficient. It is good for the environment. In my past life, I worked for a company that owned about 20 co-generation plants. They are very good for the environment, and they are very good for the system. Again, you get into the—and those were large plants. But as you get into smaller combined heat and power plants, the majority of the rules that are prohibiting their application into the system are at the State level. They are not at the federal level. I think this—FERC has tried to implement standard interconnection agreements, and they do affect large generation that is tied into the transmission system, not that—at the distribution level that is under State regulation.

Chairwoman BIGGERT. Thank you.

Mr. Casten, you talked about some of the—where your company—at the steel mills, et cetera, but could you just kind of describe the products or services and then what benefits do your products—projects offer to both your company and to your customers?

Mr. CASTEN. Every steel mill puts coke and iron ore in a big blast furnace and makes iron out of it. It emits a very dirty, low-energy gas. EPA requires that gas to be flared to clean up some of the pollutants in it. Three of our projects put in a special boiler, burn that gas, cleaning up the pollution, and then just recycle the energy and turn it into electricity and steam, all of which goes to the steel mill, cuts down their purchase of outside power and cuts down their pollution, et cetera. There are comparable projects with most chemical factories, refineries, other places with the same type of thing. So they benefit from lower prices, the grid benefits from less demand on the system.

Chairwoman BIGGERT. Is this something like methane gas from landfills or anything that could be used?

Mr. CASTEN. Methane gas from landfills is a great example of recycling. It can use some other technologies, because it is about half as energy intensive as natural gas. The stuff we are burning is eight percent of the energy of natural gas, so there are a variety of technologies to get the different waste heat, but yes, many things can be done.

Chairwoman BIGGERT. Thank you.

My time is up, so I will recognize Mr. Lampson for five minutes.

Mr. LAMPSON. Thank you. Madame Chair.

Let me start by asking Mr. Glotfelty and Mr. Glauthier a comment on Mr. Casten's testimony. What are your feelings and maybe concerns? It doesn't matter whoever wants to start.

Mr. GLOTFELTY. I believe he is on target. I mean, he—again, he has addressed one of the issues that needs to be addressed in order for us to get a more efficient and reliable system. It—I think from my standpoint, if we got, even in our wildest dream, 20 or 30 percent integration of distributed resources in our system, in a decade, that would still mean that 700,000 megawatts would still have to travel over our transmission system. So we can't neglect the transmission and distribution system and put all of our eggs in the distributed resources basket, because it will not supply all of our needs in real time. But it is a critical component that can help us over the next decade achieve a more reliable and efficient system.

Mr. GLAUTHIER. And I agree with that. I think we need to go even further than Mr. Casten did. We really need to think about distributed energy resources that include photovoltaics and other renewables, ultimately fuel cells in widespread use. The system that will support that needs to be modernized. The distribution system, as well as the transmission system, needs to be upgraded to a point where it can incorporate that kind of equipment and support it effectively. We need to be able to make that kind of distributed energy, literally point and play. So you know, as you bring home a new printer for your computer, you plug it in, and the system recognizes that and initializes and it can incorporate that. Today, that is not the case for electricity. Every new application is a custom connection. We need to make that sort of technology improvement. And that is part of the modernization that we are supporting that I think the Department of Energy can lead and the

Congress can help to provide the kind of direction and support for it that we think is important.

Mr. LAMPSON. Mr. Glauthier, you have seen the New York Times article from Tuesday this week regarding reactive power?

Mr. GLAUTHIER. Yes, I have.

Mr. LAMPSON. Can you tell me a little bit about reactive power first? And then has EPRI done a study relative to reactive power and the August 14 blackout?

Mr. GLAUTHIER. EPRI has conducted some analysis of working with First Energy and with the data there and has submitted that to the Department of Energy to the—for the use of the task force, that is the international task force. And we expect that that will be some of the information that they will be able to put together to come up with a final answer on what had happened.

The reactive power itself is something I can give you a brief explanation, but I am not an electrical engineer. And I do have with me, as I mentioned earlier, Dr. Sobajic from EPRI, who could give you more in detail if you would like to have that.

Mr. LAMPSON. Just a simple, if you can.

Mr. GLAUTHIER. Reactive power is necessary to be able to allow the regular power to flow through the lines. And there has to be enough of this balance, if you will, to allow the whole system to operate. So if you have plants that are operating and just providing their power into the system and not reactive power, they—those have to draw reactive power from somewhere else. It is a necessary balance in the system. And that is something that utilities in the past were, I think, more able to provide because the whole systems were integrated. As we restructure the system and we have independent entities performing the different functions, that becomes more complicated. It requires more coordination and more coordinated management.

Mr. LAMPSON. We may explore that more in time. Is it possible that this committee can have a copy of that study? Could you get it to us?

Mr. GLAUTHIER. At this point, we would be willing to submit it to you, but it is really a restricted report, because we are trying to provide it to the task force for its use, and we envision making it public later on as part of the data that, I think, everyone will have access to eventually. So we would ask that you would respect that, if you would, and on that kind of a basis, we would be willing to do that.

Mr. LAMPSON. Okay. We would like that when it is possible.

Let me—my time is running very short now, and this is sort of an open-ended question that I have, and I want everyone to respond to. Perhaps we can start it and then on the second time around, we will continue what I am doing. But I thought it would be interesting to hear your comments, all of you, about the top three technologies that are already developed and need to be deployed in order to increase the reliability and efficiency of the bulk power transmission system and perhaps the top three technologies that need to be developed for further—to further increase the efficiency and reliability.

And the red light came on, so that is my question. When we come back around the second time around, that is what I would like for you to begin with.

Chairwoman BIGGERT. Thank you, Mr. Lampson.

The Chair recognizes Dr. Ehlers for five minutes.

Mr. EHLERS. Thank you, Madame Chair.

I—first of all, I just want to commend Mr. Casten for what he is doing. This is something that is badly needed, and we really have to expand it across the country. This is something we have known about for years and just never get behind it and push it, because everyone likes to think of grand projects rather than small projects. I was not aware of any discrimination by the State public utility commissions on this. I thought they were all adapting to it. If that is a problem, that is something we can try to address.

Mr. Glauthier, I really appreciate your comments about a smart grid. Something that really has irritated me since the blackout is the repetitive theme I heard initially on the news media that the grid is so complicated, no one can really understand it. And that is one of the most absurd statements I have heard, because there are far more complicated systems that we deal with in this world than the grid. And clearly, we know how to do it. We can understand it. And we have to do what you said, build a smart grid that incorporates our knowledge of today into a system that is a little bit, perhaps, archaic.

Having said that, I do want to pursue the reactive power, since you said you brought an engineer around. And I don't know how many of you are engineers. But I would like to hear the explanation. Is it just caused by the phase difference between the—or is this something different?

Mr. GLAUTHIER. With your permission, I would be happy to introduce Dr. Sobajic. Would you——

Mr. EHLERS. Okay.

Dr. SOBAJIC. Well, I will try to do this simply, although—I am Dan Sobajic. I am working for EPRI. I am Director of Grid Reliability and Power Markets. And this is a subject that has been brought up in many occasions like this one, you know. And sometimes we engineers, you know, have a difficulty explaining. We go through analogies to make people understand it.

Mr. EHLERS. Well, we have two physicists here, myself and a staff member—no, three now.

Dr. SOBAJIC. Well, you are——

Chairwoman BIGGERT. This is beyond some of our pay grade, however.

Mr. EHLERS. So you can get technical for us, and——

Dr. SOBAJIC. Well, let me put it this way. T.J. just mentioned that if you deal with the ultimate in current, as we are dealing mostly in our grid, the power that flows is not active or reactive. There is just the plain power. And this is what you have down the lines. And power is the contract. It is what mathematically becomes the product of the voltage and current and if you like to go deeper in the electricity. However, these systems, when analyzed, and this is what we have to do in order to understand them very well, leads to some representations that involve complex numbers, if you like mathematics. Okay. And these numbers have a so-called real and imaginary part. Now you, perhaps, remember that. This is what we call active power or the part that is the real part or it is active. And the other one is so-called reactive. Okay. It doesn't mean that it is imaginary. Again, this is what mathematicians like to call it. But this is—these are the components of that phenomenon. And then you can go further on and analyze what are the effects of these two components when you break it up. And you can see that both of them are needed. You know. Active power, as we all know, does the work, and reactive power is very important to allow active power to do the work. So it is—it leads to an analogy that someone said it is about a car. You know, you need the gas to drive it, but you need the oil in order to be able to start the car and move. It is not quite there, but this is sort of coming to what it is.

So basically to put it, the bottom line is that you need to respect the need for the active power in order to be—to have an efficient functioning system. And I think I should stop there, because the rest goes into the market rules and why don't we have it and so on and so forth.

Mr. EHLERS. My question is are power companies deliberately ignoring this in order to push more real power out and therefore connect—collect more money without taking care of the complex variables involved? Say hey, there is a limit to what you can do here.

Dr. SOBAJIC. I think what one can see is that the way how the market system has been set up, it is clearly promoting delivery of the active power. The reactive power is, as we call it, an auxiliary service, which is already—which is the word auxiliary. It means, you know, something, perhaps, outside or—that is definitely needed, but——

Mr. EHLERS. But does a power generator make more money by ignoring the ancillary?

Dr. SOBAJIC. Well, I think the auxiliary services are also recognized in the market model and provided for. Whether there is a balance in how these services are both recognized in terms of the market rules, that is a different question, but clearly there is a financial incentive whether to do the active or not. Thank you.

Mr. EHLERS. Okay. That is what I was trying to get, whether it is a physical problem or a financial problem.

Dr. SOBAJIC. No, it is not a physical problem.

Mr. EHLERS. Okay. Yeah.

Dr. SOBAJIC. I think systems are quite capable of——

Mr. EHLERS. Okay. So it is a financial issue and therefore it should be subject to regulation?

Dr. SOBAJIC. Possibly.

Mr. EHLERS. All right. All right. If Mr. Smith wants——

Dr. SMITH. Sir, may I speak just briefly to this point? Think of reactive power as being associated with voltage and frequency control. If you don't provide it at the end of a long line, a long transmission line, it very much limits the capacity of real power that you can get through that line. It is possible, entirely possible that if—that someone might gain by limiting the transmission throughput by providing inadequate reactive power to compensate for the absorption in that long line. But this is—I think it is—why it is important ultimately that reactive power as well as real power be priced out node by node, and I think we—and I think that technology is going to allow us to do that in real time. And we are moving in that direction. I have worked with the Australians, and they are right now particularly—very much interested in pricing—developing pricing systems for reactive power in the grid.

Mr. EHLERS. And I might just observe there was a similar problem years and years ago when two electrical plants first interconnected, because they would play games having a phase lag and trying to gain financial advantage that way.

Dr. SMITH. Yes. Yes. That is entirely possible. That is the reason why you want to pay people for producing reactive power.

Mr. EHLERS. Thank you very much.

Chairwoman BIGGERT. Thank you, Dr. Ehlers.

The gentleman from California, Mr. Honda.

Mr. HONDA. Thank you. Madame Chair.

I find this discussion pretty interesting and for a novice, I think some of the lines are becoming pretty clear. What I hear folks saying is that there is a distinction in terms of policy arenas that one is federal and other state. And so it sounds like that there could be some artificial barriers just because of that. And what I hear other folks say is that if you are thinking about the consumer, and it seems to me if you look backwards in terms of policy making, then it would be—creates a different paradigm of the areas of responsibility. And it seems like if we go from the consumer backwards to create a policy for energy, it might make more sense than solving some of the problems in terms of barriers. Because what I have learned about our problems is that the grid and the transmission and the generation of electricity and the consumption is not state. It is regional. And so, you know, it seems like there are some archaic paradigms that we are forced to work under.

I guess my question is are there different ways of looking at policy development rather than separation of federal and State and looking at the consumer and developing policies that way. And I think I agree that we have to have a smart grid, you know, for us to have at this period of generation of energy so that the consumer ultimately ends up being the winner. What would be your comments to the observation I am trying to make and trying to understand, wrap my arms around?

Mr. CASTEN. May I answer?

The policy all stems from the fact that the paradigm is that all power flows through their wires. They are a natural monopoly. We have to protect the monopoly, and so we have set up a very powerful set of vested interests to make sure that all power ever used will flow through those wires. And the regulators see it as their job to protect that. As a consequence, we don't look at it from the consumer point of view and say what would we do in an optimal situation without this. The example just discussed is classic. In all of the power plants we have ever built, we have often been required to support the voltage at the back end, to change our power factor to help out the grid. We have never been paid for it. It is a value that you need, that the consumer needs, but the system doesn't want distributed generation. And consequently, we don't do the right things. We really have to fundamentally go back to saying no more monopoly on wires, and then it will start to unfold itself.

Mr. HONDA. Thank you.

Dr. SMITH. Let me say that I think here is the problem. Every customer is charged for this cost for the wires and all of these capital investments. It is determined by peak demand, not average demand. A customer who is served by energy sources closer to him, which is what Mr. Casten is talking about, shouldn't have to pay the full price for the capital costs. He is not using it, or he is only using it for backup or something like that. And he should have substantial savings from that. And until you have that kind of a system, you are not going to have the ordinary innovations that occur in response to the people's attempt to profit by doing things better. You just simply don't have maximum opportunity for that development to occur. So when you compare the electric power industry with industries that—telecommunications and computers and everything, you see an industry which is not nearly as flexible and not as prone to innovate. And we are talking about innovating in the interests of the customer: saving him money and giving him better service.

Mr. GLAUTHIER. I think your observations are very interesting in that there are many states and Federal Government are trying to find ways to spur this kind of innovation and flexibility for customers. Many of the states are going through restructuring or trying to find ways to do that that allows the innovation but also protects the customers. This is one area where the commodity we are dealing with is an essential requirement for everyone. Electricity underpins our whole way of life, so it is not an optional item but rather one that they need to be sure there is an adequate protection. And there also are generally going to be connections into the grid. We are not talking about applications where people are going to generally go off the grid and be totally independent, so you need these things to be interconnected and to be integrated.

I think what we need is also the technology development that will support this. Right now, the communications system and the power system are not integrated, so in order to do the real time pricing that Dr. Smith talked about or to provide the real dogmatic load management systems, you need communication to the customer site, so the customer systems recognize when there is a peak in the demand and they ought to scale back their own use or at what points they really change their generation and perhaps generate power into the grid. But I think these two go together; the regulatory questions and the technology development are both important.

Mr. GLOTFELTY. Very quickly, I would agree with most everything that was said but go back to the jurisdictional issue, which I think is the biggest problem. The interaction with the retail consumer is governed by the state, which means we have 50 different State rules on how we get distributed resources or demand side management or control technologies onto the grid to allow more consumer interaction. And that is a tough issue to crack, considering that retail consumption of electricity is not an interstate commerce, as is the wholesale market. It is something that I think Congress is trying to address. But in the meantime, the Department of Energy, as well as many associations and groups, have been working with the states to try and get model interconnect agreements and model policies that can be adopted at the State level to increase the deployment of these technologies. However, it is not as quick as it could be. But it is a challenge, and it is moving down the road.

Mr. HONDA. Thank you, Madame Chairman. Just a real quick comment. I think if the consumers got more educated, there would be some changes.

Chairwoman BIGGERT. Thank you, Mr. Honda.

We do have a vote coming up, but we have got time for another round of questioning from Dr. Gingrey.

Dr. GINGREY. Thank you. Madame Chairman. I will make this brief, because I know we do have to go vote.

Excuse me. Mr. Glotfelty, the National Grid Study, which led to the creation of your office, called for the elimination of transmission bottlenecks, can demand response technologies and distributed generation technologies help eliminate the bottlenecks and the grid congestion generally? And if so, how would we best encourage these technologies?

Mr. GLOTFELTY. The answer is a resounding yes. There are models out there for demand side management that today decrease bottlenecks. A great example of that is in southwestern Connecticut. They have had a very hard time building additional transmission lines. With the implement of a market in the Northeast, prices this past summer were going very high. A new demand side management program that the Department helped support but was supported by the utilities as well as the state, allowed a tremendous demand response, which reduces—reduced prices for not only the consumer but for the whole region. There is a great example, and it is a great model that can be replicated across the country.

For distributed resources, I think there are a lot of models from the—in the Southeast to California. Other states have good models for putting additional distributed resources on the grid. I think, again, we go back to this State issue. Each State is different and each region is different, so the model is going to have to fit each region.

Dr. GINGREY. And let me ask both you and Mr. Glauthier. Some have suggested that much of our transmission and distributive congestion could be relieved by simply replacing the basic 1950's era grid technologies, such as the wires, the transformers, and the mechanical switches with today's state-of-the-art technology. For example, we have heard of wires, and I think you mentioned this earlier, that carry three to five times more power or digital switches that improve the capacity of the grid. How much would this help compared with the technologies you have proposed and that others have mentioned? And how would its costs compare with some of these alternatives that we have already discussed this morning?

Mr. GLAUTHIER. Thank you.

I think those are very important, and I think they are all part of the overall solution, that there is not any one solution that will take care of this. The transmission lines, or conductors as you talked about, are under testing by the Department of Energy and by EPRI and others. And there are at least five or six different manufacturers of that. So there is the opportunity for some competition among those. And they are quite cost-effective, if they prove out. Right now they are in the testing phase to be able to be certified for use in commercial applications. So our hope is that those will be ready soon, perhaps in the next year or 2 years that those can begin to be used.

Other digital controls also can be installed, but in some cases, the cost needs to come down. There are the FACTS devices, the Flexible AC Transmission Systems I described. There are only nine or ten of those installed in the country right now because they cost several million dollars a piece, in some cases $10 million or more. But those are solid State controls that can actually direct the power flow and can eliminate loop flow problems and other difficulties. That is the kind of thing. We need to spur the development of a family of those controls that can be scaleable down to smaller sizes and be cheaper and be installed in numerous locations throughout the whole grid.

Dr. GINGREY. Thank you. And thank you, Madame Chairman. That concludes my questioning.

Chairwoman BIGGERT. Thank you, Dr. Gingrey. As you heard from the buzzers, and if you heard the beepers that—we do have a vote on the House Floor, so we will—it is just one vote, so it should not take us too long. So we will stand in recess to the call of the Chair.

[Recess.]

Chairwoman BIGGERT. If we could resume, the witnesses will then take their seats. All right. We will call the Committee to order again. As long as some of our Members have not returned, I think that we could give five minutes to Mr. Lampson on the question that he asked earlier.

Mr. LAMPSON. Thank you very much. I might as well start.

I had already posed the question to you, and so if each of you would talk about the technologies that exist and we need to implement and those that we might need to try to develop over time. Right. From the left to the right. All right.

Mr. GLOTFELTY. From our perspective, I think the technologies that are here today that just need to be deployed onto the grid are: higher capacity transmission lines; wide area measurement systems, which measure the state of the grid, voltage, all sorts of components of the grid in a wide area, we have it in the West, we do not have it in the East; and training for our operators to use this new technology that is coming. It is critical that they have an understanding of how new power electronics and new technologies can help them make the system more reliable.

I think in the future it is high temperature superconductivity and the wide variety of technologies that come from that, whether they be cables, fault current limiters, or other technologies that really have no losses. It is storage and it is power electronics. Storage has the ability to help peak shave. It has the ability to help provide backup for entities that—like batteries. There are new technologies coming down the road that can help entities be more efficient as well as firm up their reliability for their industrial processes. And power electronics, of course, is something that we are working on with EPRI as well as the industry on how we make sure that the grid is controllable, how we can isolate problems without them becoming widespread where we can really ensure that the grid is reliable in the future. It is a few years off, but we are working on it today.

Mr. GLAUTHIER. Thank you.

I add to that list a couple of things that are here now. The State estimators is a software term that—systems that can calculate within seconds, the PJM system about every 30 seconds calculates the state of the system from all of the data coming in exactly what is happening. The State estimators are not being widely used in most of the systems around the country. The systems need more sophisticated work so that the operators will really feel that their information coming out of them is reliable. That is an area that is here. It can be done now. It is—needs to be improved so that operators have the best information possible as they are running the system.

Along with that is wide area data to the operators so they can see what is happening in neighboring control regions. They have the data on their own control region but they have no idea exactly what is going on in the areas around them. It is very helpful, and it is possible with today's technologies. In fact, it has been demonstrated in some applications that DOE has done and that we have done how to do this and how to make that data available on a real time basis.

Mr. LAMPSON. Are either of those extremely expensive to implement?

Mr. GLAUTHIER. No, they are not. They are——

Mr. LAMPSON. Well, why aren't we already talking about doing it then? Why——

Mr. GLAUTHIER. Part of it has to do with access to the data. It is providing data to your neighbors, you know, your own operations. There is some extra software development and some costs involved, so it just hasn't been high on the list, but it is something that I think we need to make a greater priority. And now that outage in August will perhaps give more visibility to that sort of thing. It has just not been viewed as one of the top priorities.

I would echo what Mr. Glotfelty said about the transmissions lines, the new conductors that will be able to carry a greater amount of throughput so you could re-conductor some existing transmission corridors and get more power through those without having to build or permit new transmission corridors and the like.

On the existing technologies, I would also say real time sensors. We have sensors in all sorts of applications now in other sectors. We are a wireless society and becoming a wireless society, but the electricity sector is not—has not caught up. The electricity sector is not as widely computerized and is not using the real time information that it could. Mr. Glotfelty mentioned the wide area monitors or sensors in the West. We ought to have them throughout the whole system and it—and all sorts of equipment. Ultimately, every piece of equipment is going to be sending in information about how I am doing and what is happening.

In terms of new technologies, the power electronics area is really important. I mentioned the FACTS systems earlier that can actually control the power flowing through an area of connection. And right now, the wires are just a set of dumb wires. The wires are out there, and you put power into one place and it will flow through the system. But we need real controllers out there. And we can do that, but they are expensive. We need to develop a more cost-effective set of those, a scaleable set that will be able to be used widely throughout the system.

Just two other quick things. The technology to get the distributed energy resources, the kinds of things that Mr. Casten has talked about and in addition solar powered and many other kinds of renewable power, to be able to be plug and play. That is actually something that can be done. We are working on it with the manufacturers and vendors. The Department of Energy is working on it. It is not something that is going to take a long time, but it has to be done in a way that provides the standardized protocol, the standardized methods so that these can be widely used.

Mr. LAMPSON. Madame Chair do you want to let—just let them—we still don't have anyone else to—or do you have a question that you want to go on a different direction on and we will come back to the last two on?

Chairwoman BIGGERT. No.

Mr. LAMPSON. Okay. Then——

Chairwoman BIGGERT. Proceed, Dr. Smith.

Dr. SMITH. I think the problem is to have—try to get in place incentives that enable people to put their own money up, incur the cost of investing in some of these new technologies and getting the benefit from it. Now what is hard, of course, is that those benefits are widely distributed in the system. And the problem—and the grid. And the problem is to figure out how those savings can—the individual who incurs the investment can, because of the savings he is enabling the system to enjoy, to capture revenues in response to his—to the investment costs that he incurs.

Now I would ask—would like to ask Mr. Glauthier if he sees—if he is at all hopeful that the control system could enable you to also compute benefits and savings and come up with a way of pricing this so that the individual who invests in it can benefit.

Mr. GLAUTHIER. I think the answer is yes, if I may.

Mr. LAMPSON. Please. Go ahead.

Mr. GLAUTHIER. Really having the access to the data and having a set of information coming in through—from throughout the system on a real time basis does give you the power then to construct different kinds of pricing systems, to administer them, to make the whole system a richer and more robust way of managing.

Dr. SMITH. That is all I have.

Mr. LAMPSON. Okay. Mr. Casten, do you want to tell me about those technologies?

Mr. CASTEN. Thank you.

The three most important, hands down, the microprocessor. Old power plants required six to eight attendants per shift. And when you double up all of that labor, you just can't make a small power plant economic. The microprocessor lets us operate any kind of technology unattended. And it just takes the scale out of—one of its advantages. Another advantage is that we do connect up in real time to all of our customers' meters. And once we have got a customer, we do what we say the—what Dr. Smith says the grid ought to do. We are monitoring and actually causing them to drop their peak loads to make better use. That is one.

Number two is the advances in gas turbine efficiency. When I entered this business 25 years ago, the best gas turbine was 22 percent efficient, and the best thermal plant was about 33 percent efficient. Today, the best thermal plant is still 33 delivered. The best gas turbine is about 42. You can combine the cycle and get it up to 55. The best news is that if you take the two most efficient gas turbines in the world today, one of them made by Solar is four megawatts, about the load on the Hinsdale Hospital. So there is no reason why you can't put these things out. In fact, it makes no sense to burn gas anywhere but locally, thanks to that and the third technology.

The pollution control is astonishing what has happened at the source. The best turbine available 25 years ago was about 200 parts per million of NO_X, which is roughly comparable to what you get out of a big thermal plant. The best ones today are two parts per million. So we formed this whole paradigm that the power plants had to be located a long ways away, because they had to be located a long ways away. They were ugly and dirty and needed a lot of people. Today, they are inconspicuous. There could be one in the basement of this building, and you would never know it.

With respect to the second part of your question, what technology is needed, I can offer only two. One I wholly support Dr. Smith's idea of getting to the point where there is a signal on the wire telling every consumer the marginal cost of power at that moment so that smart appliances could pick it up and decide whether to wash my dishes right now or wait until three in the morning. The other thing I think the Committee could look at is some work on technologies that we cover energy from lower quality heat. That is a field that hasn't been investigated very much. There are some promising ways to use even lower temperature heat and convert it to electricity, and that needs some science, some fundamental science.

Thank you.

Mr. LAMPSON. Thank you all very much, and I yield back.

Chairwoman BIGGERT. Thank you. Then I will continue with the questioning.

Mr. Glauthier, many have said, and I think that you agree, that we have under-invested in the grid. And I wonder if you have some indicators of this under-investment. But I also want to go a little bit further than that, because we are talking about a grid, and we have heard a lot—most of you had mentioned at some time we run into State laws and that—and another factor has been that because of the deregulation that this has had a—has been a factor in the blackouts that we have incurred. So is there—do we have a choice of whether we are going to really improve the grid? Should we have a national policy so that we can, you know, avoid the State laws and, for example, then Mr. Casten would be, perhaps able to cross the street with his—with private lines? It seems like we have got an awful lot of factors here with the regulation that is causing part of the problem. And maybe start with you, Mr. Glauthier.

Mr. GLAUTHIER. Yes. Thank you.

Investment has been lagging in the grid, the distribution and transmission parts of the system, and especially the transmission part, for the last decade. Part of it is due to the confusion that there has been about what the regulatory structure and the ownership responsibilities will be for the transmission system. There are changes that the Federal Energy Regulatory Commission has proposed, changes that individual states have put forward. And many cases, the owners and potential investors in the grid just need the rules clarified. They could——

Chairwoman BIGGERT. And I believe that that is also in the National Energy Bill that we have right now that is in conference.

Mr. GLAUTHIER. It is. And it is part of the energy proposals by this Administration and the previous Administration to try to make those decisions. So that will help. And there is, I think, a question about the returns. There is a lot of discussion about what rate of return is sufficient to bring about that kind of investment. The question really needs to be focused on what is the realized rate of return. It is one thing to have an allowed rate of return, but if, because of rate freezes or because of other delays or other things, they are—companies are not able to realize the returns that are allowed, that is an issue. So I would suggest that people need to look at the reality of what returns actually will come.

Chairwoman BIGGERT. Okay. Do you have any figures on that that you would——

Mr. GLAUTHIER. Well, the investment right now in the transmission system and the grid is about $3 billion a year. And the estimates that the Electric Institute has used is that they think it ought to go up to about $5 billion a year to—really to maintain the current system. And our feeling, as I said earlier, is that we think the investment needs to be about $10 billion a year in order to modernize the system so that you are not just fixing the current system but you are also moving ahead to really add the computerization, the sensors, the real time controls that are needed to make this system operate in both the reliable and secure fashions we described and to enable the kinds of applications that will really make it possible to use it so that customers can control their loads better and you can get more distributed energy and other things connected.

Chairwoman BIGGERT. Well, given the cost of transmission improvements then tenths of a cent per kilo-hour and the benefits to customers that you describe, which are orders of magnitude higher? Should the rate payers bear this cost?

Mr. GLAUTHIER. Rate payers probably will, and it is not a huge cost. The total of all electricity revenues right now in the country is about $250 billion a year. So if you add $10 billion a year to that, that is a four percent increase. But the key is that this needs to be an incremental investment. The utilities already are spending the money to try to keep their current systems running and to keep the lights on for everybody. They are operating under regulatory controls at the states where people are trying to keep the customers—give the customers the lowest rates possible. Everyone needs to realize that this is an investment in the future and it will provide a lot of benefits.

As Dr. Smith said earlier, the benefits are widely dispersed, and so it is harder to identify exactly who gets those benefits. But there are real benefits there. Our estimate is that the cost of power disturbances right now is about $100 billion a year, year in and year out. And that is not the cost of the August outage. That is just the regular disturbances, not always blackouts, but often the fluctuations that are enough to make a chip producer go off line or to make a pharmaceutical batch that has been going for 10 days unusable, things of that sort.

Chairwoman BIGGERT. And would special financing be required?

Mr. GLAUTHIER. What our recommendation is that the Department of Energy be instructed to look into this and work with the customers. Work with the State regulatory commissions, work with the industry and other stakeholders, and come back in a year with the recommendation. We think that there may be mechanisms that would provide incentives for this investment or other ways, perhaps working with the National Association of Regulatory Utility Commissioners to have the states, as a group, embrace some approach to going ahead. Ultimately, the customers probably pay all of this cost, but if there is a concerted effort to do it and a commitment to really move ahead and invest something in the system, that is what is going to make it happen. A business-as-usual approach is probably going to take a long time and just, you know, be very, very slow.

Chairwoman BIGGERT. Would anybody else like to speak either to the under-investment or to the national policy or—Mr. Casten?

Mr. CASTEN. The slight problem with the investment is that the industry knows how vulnerable it is to continuing the present model. And if the industry doesn't know, the banks do. And so there is a growing reluctance to put a lot more money into wires, which are probably obsolete before you ever build them.

And my second comment is that I don't know how any of this mess gets straightened out until Congress asserts that electricity is, indeed, interstate commerce, because you have heard that all day. And it is just really a problem with all of the states asserting jurisdiction.

Chairwoman BIGGERT. Anyone else?

Dr. Smith.

Dr. SMITH. I think the real problem is not so much under-investment but the direction of investment. You see, we have these technologies that can improve the grid and make it more efficient. We also have technologies that completely bypass the grid that Mr. Casten was talking about. And I have a question I want to raise. Suppose that I own a high-rise apartment, in particular this is for Mr. Casten, but for anyone else. Suppose I own a high-rise apartment house, and I want to buy one of those four-megawatt units to supply my own power needs, and any excess capacity, I want to dispatch it out to the rest of the world through the local substation. What are the barriers to my doing that? Can I do that?

Chairwoman BIGGERT. Physically or legally?

Mr. CASTEN. Can I answer that?

Chairwoman BIGGERT. Sure.

Mr. CASTEN. First of all, the commission is going to say that it is okay to charge you for 100 percent of all of the facilities to back you up, because you might go down at the time of the absolute system peak. So you are going to pay for all of the wires anyway, and this is going to mean you probably don't want to do it. If they charge maybe four percent, you would cover it.

Secondly, the power from that generation excess is going to flow to the nearest user. It does by the laws of physics. But you will be given a discounted amount for the extra power, based on what the wholesale market is from big plants minus a discount because it is too small to mess with. You will get no locational value for the fact that your little operation is actually going to strengthen the local grid. You will get no value for the fact that this is going to help the big utility avoid the cost of putting another buried transmission—or distribution line in the street. So the commissions will look at the costs only, not look at the benefits. And the net result of all of that is that you will probably decide just to stay where you are.

Dr. SMITH. Thank you.

Chairwoman BIGGERT. Thank you.

And if I might, I have one more question, and this is switching gears a little bit, but as we proceed with our energy bill conference, which I am a conferee and Mr. Lampson is a conferee, we will be looking at authorization levels and which will be higher, but—for these R&D programs. And in addition, in the electricity provision, we are attempting to push the regulatory reforms that really have—we have discussed here today. Which of these, in your view, is of greater importance, the R&D or regulating reform? So I think we will start with Mr. Glotfelty.

Mr. GLOTFELTY. I think they are equally important. The R&D must continue, whether it is done at the basic level with the government and universities or the more applied level with industry, to make sure that those technologies actually get deployed in the grid. But they won't be deployed into the grid unless we have the regulatory reform. The cost that we are talking about of upgrading the grid, if they cost $100 billion, may very well be offset by the reduction in energy costs. If your bill is $100: $10 is transmission, $10 is distribution, and $80 is energy, if we increase the transmission component or even the distribution component as well to allow these other technologies and you decrease—and that incremental increase can very well be more than offset by a decrease in energy costs. Distributed resources, demand response reduce costs for everybody, not just the single user.

So I think they go hand in hand, and they both must be addressed as we move forward to make this system more reliable.

Chairwoman BIGGERT. Thank you.

Mr. Glauthier.

Mr. GLAUTHIER. I would note that the regulatory issues you are dealing with are, of course, at the federal level. And as we said earlier, many of the issues that bear on the applications that we are talking about are at the State level. So there may be a lot that can be done through means of working with the states and not necessarily all through your legislation.

The organizations I represent are R&D organizations, so let me speak to that part of your question and that is we do think that increased authorization levels are appropriate here. And the levels that are in the House-passed bill last year for the R&D and electricity area, we would increase or suggest increasing about $500 million a year. I mentioned earlier that we thought that the program ought to be $1 billion—I am sorry, $100 million a year, $500 million over five years. That ought to be about $1 billion. There is currently about half of that in those levels for these kind of programs. So we think it ought to be increased but not by the full amount that I said. Importantly, I think it ought to be increased to be transmission and distribution system R&D, not just for the transmission system. The very things that we talked about here that are really done at the customer level typically are through the distribution system, and so it is important that the R&D do both. We need to modernize the whole grid, not just half of it. And importantly, too, to include demonstration projects so that the Department can work with those utilities or those customers who are at the leading edge of technologies and help support the first applications in order to get those technologies demonstrated and really into working order.

So I would emphasize those three elements of the R&D program.

Chairwoman BIGGERT. Thank you.

Dr. Smith.

Dr. SMITH. I am sorry. I have no more comments on that, but I may have another question later.

Chairwoman BIGGERT. Okay.

Dr. SMITH. I am learning here on some of this technology, okay. My background—I do have an engineering—electrical engineering degree, but it is from Cal Tech in 1949, and I don't stay up. I am doing economics, so I am really delighted with this——

Chairwoman BIGGERT. Well, we are delighted that you are here, so thank you——

Dr. SMITH [continuing]. Interchange.

Chairwoman BIGGERT [continuing]. For your contribution.

Mr. Casten.

Mr. CASTEN. I would like to give you a very clean answer. The regulation. The—a veritable Hoover Dam that holds back thousands of technologies that—many of which appropriations of this committee over the years have helped to bring forward. But they sit there. Let those flowers bloom and then we can do a better job of figuring out what kind of new fertilizer we need. Right now, we don't know where those flowers are going to go, because they are all held back. So fix the regulation first.

Chairwoman BIGGERT. Thank you.

Mr. LAMPSON. I want to go back to Dr. Smith's question. What is the solution? Is there a solution to this? Is there a way to reach a point? Is total deregulation of letting anybody go out and do whatever they want to do the answer? What——

Dr. SMITH. Well, regulation by—people are always regulated by markets and prices. The question is how free should those prices be? And Mr. Casten was saying that is—in answer to my question here is we have these technologies, which also have the advantage that they completely bypass the grid, so you don't even have to use this. You don't have to worry about more investment in it. Although it still may be used as a backbone, as a backup, of course. And there just isn't the price incentive there for anyone to do it, to invest in that, because of the local regulation. And I agree with Mr. Glotfelty that the problem is really at the State level in the kinds of issues we are here—that I am talking about. The problem is at the State level, and that is why I am spending more of my time at that level and not up here testifying in Congress, because I think that is where the problem is.

I think the danger, though, is that if that is not fixed at the State level, then at the national level we will do things that are not cost efficient because we are forced at the national level to invest in more supply side capacity and that is not at all—need not at all be the most efficient way to create a more flexible system. I don't know whether it is feasible to—for the feds to simply declare that electricity is a commodity, whether it crosses State lines or not, and gets in the business of separating wires from energy. I think that is what we have to do. Energy is a commodity that can be supplied competitively. And the local utility ties in the sale of energy with the rental of the wires, and they have good motivation to do that. But I believe that that should be—they shouldn't—that tie-in sale should not be taken for granted as a part of the regulatory apparatus. And that should be entirely opened up so that the energy part can be supplied competitively, either with demand interruption technologies and control or with generators closer to the customer.

Mr. LAMPSON. Well, this has all been fascinating, and we have lots more to learn, and I am sure that we will be spending a good bit of time before we take the next steps, but thank you all for being here, and thank you, Madame Chairman, for letting me participate.

Chairwoman BIGGERT. Before we bring the hearing to a close, I would like to thank our panelists before the Subcommittee today. You truly are experts, and we have—I think we have had a great hearing, thanks to you. So if there is no objection, the record will remain open for additional statements from the Members and for answers to any follow-up questions the Subcommittee may ask the panelists. Without objection, so ordered. The hearing is now adjourned.

[Whereupon, at 12:05 p.m., the Subcommittee was adjourned.]

Appendix 1:

ANSWERS TO POST-HEARING QUESTIONS

ANSWERS TO POST-HEARING QUESTIONS

Responses by James W. Glotfelty, Director, Office of Electric Transmission and Distribution, U.S. DOE

Questions submitted by the Subcommittee on Energy

Q1. The creation of the new Office of Electric Transmission and Distribution separated R&D for transmission, distribution, and interconnection from R&D for distributed generation. What was the reasoning behind this? How do you intend to ensure that these R&D programs remain coordinated?

A1. The R&D division corresponds with appropriations subcommittee lines (distributed generation is under the Interior and Related Agencies Subcommittee; T&D is under the Energy and Water Development Subcommittee). The new office includes all of the activities previously funded in the Electric Energy Systems and Storage activity in the Energy Supply account (EWD appropriation): high-temperature superconductivity, energy storage, electric transmission reliability, and distribution and interconnection. The Energy Conservation account (Interior appropriation) funds R&D on industrial gas turbines, micro-turbines, reciprocating engines, and materials and sensors for those engines and turbines.

Distributed generation is a critical component of a portfolio of technologies that will help us over the next decade to achieve a more reliable and efficient electric system. However, it will compliment and supplement existing generation, not supplant it entirely. Even if distributed generation contributes 20 or 30 percent of new capacity additions in the Nation's electric system over the next decade, hundreds of gigawatts of electricity would still have to travel over the transmission system. The new Office is committed to a secure, reliable, economic electricity system utilizing all of our generation assets and technologies. We will work closely with both central generation (including large-scale renewables, coal, nuclear, natural gas) and distributed generation. The program managers assigned to distributed generation R&D and those assigned to transmission and distribution R&D will continue to work closely together, share information, and participate in each other's peer reviews.

Q2. In your testimony you state that distributed generation has important contributions to make, but will not be the single solution to reliability concerns. What is your estimate of the size of the potential market for distributed generation? Please include your assumptions about technology costs, etc.

A2. One estimate I have seen is that of Resource Dynamics Corporation, an energy consulting company that utilizes an extensive set of tools including proprietary databases and models to develop innovative business solutions for energy technologies and markets. Based on their analysis, today's installed distribution generation is 169 gigawatts, which includes some 134 gigawatts of backup units which can be used in the event of power supply failure. The distributed generation potential (using current technologies) is about 80 gigawatts (which includes combined heat and power and peak shaving, but does not include backup units). It grows to almost 180 gigawatts when future improvements in distributed generation technologies and some more innovative applications (e.g., customer aggregation) are considered.

Q3. Last year the General Counsel for the North American Electric Reliability Council (NERC) testified that "Some entities appear to be deriving economic benefit or gaining competitive advantage from bending or violating [NERC's voluntary] reliability rules." Is there a technology remedy for this problem?

A3. Installing systems to monitor conditions regionally and respond to potential problems more quickly is one remedy. High-speed, time-synchronized data systems that are now being deployed could be used to track and predict the potential for outages in near-real time. However, this high-speed dynamic information could also be used to do state estimation, system model improvement, and recalculate the "security" of grid in real time, providing the results to transmission providers for their system and neighboring systems. If mandatory reliability standards were in place, these systems could better detect non-compliance, and with the potential for penalties, the monitoring alone would provide incentive for compliance.

Questions submitted by Minority Members

Q1. What sector makes up the largest percentage of electric load: household, industrial, commercial, etc.? In the next decade where will we see the largest increase in efficiency? Where will we see the largest increase in demand?

A1. The Energy Information Administration (EIA) estimates that residential sector comprises the largest percentage of electric load (roughly 36 percent), followed by commercial (roughly 32 percent), and industrial sectors (roughly 29 percent).

On the upstream end of the supply line, energy efficiency involves getting the most usable energy out of the fuels that supply the power plants. The EIA estimates that nearly two-thirds of all energy used to generate electricity is wasted, with transmission and distribution losses amounting to nine percent of gross generation. Thus, combined heat and power, coupled with new technologies applied to the storage of energy and the transmission of electricity, will contribute to energy efficiency. With respect to load, several energy efficiency programs at the Department affect the commercial sector. These programs are designed to stimulate investment in more efficient building shells and equipment for heating, cooling, lighting, and other end uses.

According to EIA projections, the largest demand increases are expected in the transportation sector (2.8 percent annual growth between 2001 and 2025, but with a tiny fraction of the total electricity sales), followed by the three much larger electricity sales sectors: the commercial sector (a 2.2 percent annual growth between 2001 and 2025), the residential sector (a 1.6 percent annual growth between 2001 and 2025) and the industrial sector (also 1.6 percent annual growth between 2001 and 2025).

Q2. Despite the inevitable increases in efficiencies of household devices, do you believe demand per household will increase as more electronic devices are added to average house and the average house gets bigger?

A2. Yes, but not at the rate of increase in the 1960s (over 7 percent). According to the EIA (*Annual Energy Outlook* 2003, p. 66),

> "The continuing saturation of electric appliances, the availability and adoption of more efficient equipment, and promulgation of efficiency standards are expected to hold the growth in electricity sales to an average of 1.8 percent per year between 2001 and 2025. . ."

Q3. You mention that reliability will be enhanced when grid operators are able to make adjustments in real-time, to fluctuations in demand. Why are they not able to do that now? In terms of personnel, what are the primary hurdles towards achieving a smoother running system?

A3. Most of the electricity in our country is generated at the moment it is needed. To meet changing electrical demands, some power plants must be kept idling in case they are needed. These plants are known as "spinning reserves." During times of high electrical demand, inefficient power plants may be brought on-line to provide extra power, and the transmission system may be stretched to near its limit, which also increases transmission energy losses. Thus, today, adjustments to demand are primarily made at the gross level (i.e., day-ahead markets, backed up by spinning reserves).

Price responsive load, or demand response, programs could be more efficient in responding to demand fluctuations in real-time. However, wholesale market and retail rules that allow grid operators to use demand response are limited. Retail pricing and demand response programs are largely controlled by the States, and it is difficult for grid operators to influence them.

ANSWERS TO POST-HEARING QUESTIONS

Responses by T.J. Glauthier, President and CEO, Electricity Innovation Institute, Palo Alto, CA

Questions submitted by the Subcommittee on Energy

Q1. Which of the technologies you mention in your testimony could be deployed tomorrow on a mass scale? For the technologies that can't be readily deployed, what are the barriers to near-term implementation?

A1. One relatively simple technology developed by EPRI and successfully demonstrated by several utilities could contribute to improved system reliability by enabling increased confidence of safe loading levels for transmission lines above their conservative static ratings. By integrating real-time sensor data on ambient temperature, wind speed, and line sag on specific circuits, EPRI's Dynamic Thermal Circuit Rating (DTCR) system allows operators to move more power on lines with reduced risk of thermal overload. DTCR is low-cost and can be quickly deployed on thermally constrained lines. Other near-term steps that could contribute to improved reliability include improved operator training, both for normal operation under heavy loading conditions and for service restoration from outages.

On the hardware side, a mid-term solution for increasing the capacity of existing transmission corridors may soon be ready for commercial deployment: advanced high-temperature, low-sag conductors. These advanced conductors have the potential to increase current carrying capacity of thermally constrained transmission lines by as much as 30 percent or more, and demonstrations are underway.

Loop flows can be controlled with solid-state power electronics technology, such as Flexible AC Transmission Systems (FACTS) technology developed by EPRI and power equipment vendors. However, FACTS technologies are still emerging and their cost and size must be further reduced through continued R&D efforts before they are economical for widespread deployment.

Development of a number of emerging technologies that are still not yet ready for commercial deployment could benefit from increased industry and government support for demonstration efforts. These include the demonstration and integration of new inter-system communication standards based on open protocols to enable data exchange among equipment from different vendors, including SCADA and EMS systems. Two prime examples of such standards are the EPRI-developed Utility Communications Architecture for connecting equipment from different vendors and the Inter-Control Area Communication Protocol for linking control centers and regional transmission organizations.

A more complete description of how advanced technologies can help improve power system reliability and what barriers need to be overcome is presented in the EPRI report, *Electricity Sector Framework for the Future*—which may be downloaded from http://www.epri.com/.

Q2. You've outlined several specific actions in your testimony that government, in conjunction with the private sector, can take to ensure grid reliability in the future. What is the current level of investment in grid infrastructure by the private sector and what should their investment be in the future. What about for R&D investments?

A2. As discussed in the *Electricity Sector Framework for the Future,* Vol. 2, pp 29–30, infrastructure investment levels relative to revenues are now below the levels seen in the Depression of the 1930s, producing an "investment gap" of at least $20 billion a year. For example, electricity sector investments in transmission assets in 1999 were $3 billion, approximately half of what they were in 1979, and 30 percent of the recent peak level reached in 1970. In October 2002, energy analysts at Oak Ridge National Laboratory estimated that $56 billion of investments in transmission infrastructure was needed in this decade just to maintain the current quality of transmission service. The current level of capital expenditures is far short of this minimum level.

Looking toward the future, EPRI recommends a research and demonstration program that will require increased federal funding for R&D on the scale of approximately $1 billion, spread out over five years, with the private sector contributing a significant amount of matching funding. These R&D and demonstration funds represent an investment that will stimulate deployment expenditures in the range of $100 billion from the owners and operators of the smart grid, spread out over a decade.

Q3. What is your estimate of the size of the potential market for distributed generation? Please include your assumptions about technology costs, etc.

A3. Most estimates show distributed energy resources (DER) eventually representing 10–20 percent of U.S. total generation, depending on a variety of assumptions. EPRI does not have its own estimate. Rather, we have focused on determining the market potential of DER in particular applications. Specific findings include:

- New DR applications for baseload electric-only and co-generation are fairly limited. Economics for these applications are only favorable in areas with very high electric prices, low gas prices, and sites with good electric and thermal load profiles.
- Future peaking applications may offer important opportunities for using DER. For example, peaking DER can be applied in combination with a number of different electricity contract types, including time-of-use rates (to avoid buying power during peak price periods), interruptible rates (to sustain operations during outages), flat rates (to present a flatter load profile to the electricity seller), and rates with peak demand charges (to reduce peak demand).
- Significant opportunities may exist for selling DER for backup power to businesses that have not traditionally used DER for such applications.
- DER projects that provide multiple solutions to a customer (e.g., heat and electricity) are much easier to justify economically. When considering a DER project, all potential benefits need to be explored and economically quantified.

In Attachment A, "Analysis of DER Applications Potential," Table 1 shows the results of our analysis for baseload electric, co-generation and peaking power DER potential in the industrial and commercial sectors. Tables 2–4 show the assumptions involved in the analysis.

Ouestions submitted by Minority Members

Q1. If it is going to take ten years or more to get the smart grid developed and implemented, are there steps we need to be taking to make the current grid more reliable in the interim. Are we adding complexity through distributed power? Do we need to go slow on this or other innovations?

A1. Although ultimately revolutionary in its effect, the smart grid will be evolutionary in its development. Some pieces—e.g., current utility applications of DTCR and FACTS—are already being put into place. Others, such as the Dynamic Risk and Reliability Management (DRRM) system, which would enable system operators to react quickly to grid conditions that threaten to cause outages, will require that a sophisticated system monitoring and communications systems to be implemented first. It is therefore vital that government and the private sector to work in partnership in demonstrating and deploying new technologies in an orderly fashion. Specifically, EPRI is already engaged with several utilities partners to demonstrate DRRM tools on their transmission systems, and we propose a public-private initiative to hasten their widespread deployment.

The role of DER in improving power system reliability is complex. In general—everything else being equal—the closer that power is generated to loads, the greater potential for high reliability. Put another way, the longer the lines used to delivery power, the more potential there is for interruptions. Conversely, however, if DER is not integrated properly with the existing grid, both reliability and safety may be jeopardized. For example, linemen may be injured if power flows in an unexpected direction along a distribution line because of a DER unit on a customer's premises. To make sure that increased use of DER supports reliability and safety, EPRI is helping develop new interconnection standards (discussed in more detail below) and is working to make individual DER units more "plug and play" compatible with existing power systems. In the language of the question—the point is not to go slowly, but to go carefully.

Q2. We set up safety margins in other lifeline institutions. For instance, in the banking industry, a certain percentage of the financial assets of a bank must be kept as reserves, and energy generation reserves are a long-established practice in the industry. Do we need similar limits on percentage of resources that can be used with regard to transmission capacity?

A2. A distinction should be made between infrastructure capacity versus consumable resources. Bank reserves and fuels for electricity are consumables, which can be used to reduce the probability of it running out. Power plant capacities and transmission capacities, on the other hand, represent fixed infrastructure, requiring long lead time for construction. Because they are highly capital intensive, it is not economical to overbuild by a large degree. And once these facilities are built, the costs are sunk, so it makes no economical sense not to make use of them for normal operation. An analogy is building a highway with more lanes than currently needed. It does not make sense to block off a lane from normal usage and hold it in reserve.

Because generator and transmission capacities have measurable probabilities of outages, however, extra generators and lines are needed for backup when outages occur. In this way, the backup units that are not directly affected by an outage will generally be sufficient to keep most of the grid intact and deliver power economically.

In the case of setting safety margins for generation capacity, the rule of thumb is that for most regions, a 15 to 20 percent reserve margin (based on the annual peak load forecast) would be adequate. With transmission, however, there is no comparably simple reserve margin to compute, because the loading of the transmission lines changes frequently in response to economic dispatch or wholesale power market fluctuations. Flows can go in one direction at one time and then in the opposite direction some other time. Lines are often loaded to the maximum operating limit. If the demand and the wholesale power market cause certain transmission lines to be loaded above their operating limits, then the grid operators can usually re-dispatch the generation or curtail the wholesale power transactions so as to keep the loadings below the operating limits. The extreme remedial action would be to curtail firm customer loads.

The question thus arises of how to set transmission operating limits, based on the concept of providing an adequate safety margin. NERC requires that no transmission line or transformer should become loaded above its reliability limit upon the sudden outage of another single transmission line or transformer, anywhere else in the grid. This requirement is known as the "single-contingency criterion." For example, if two transmission lines serve an isolated area, then the loss of one of the two lines must not result in overloading the remaining line. For example, if each of the two lines can carry 100 MW of power, then the maximum amount of load they can serve *together* under this criterion is only 100 MW. Most of the time, when both lines are in service, they will share the load between them—each carrying 50 MW, with 50 MW of spare capacity. Then, if one line goes down, the other can safely carry the full 100 MW load.

The single-contingency criterion is based on the assumption that if a line outage happens, the operator will know about it immediately and take corrective action to bring the system to a safe operating condition where with the possible onset of another line outage, the system is still reliable. The rating of the transmission line's operating limit is based on this reaction time. For thermal overloads, the rating is typically based on the ability to sustain 30 minutes of this load level without physical damage or without sagging onto trees, causing a short circuit. Thus, if either the monitoring equipment fails to notify the operator, or the corrective action cannot be taken within the 30 minutes to relieve the overload, this single contingency criterion will not be adequate.

The blackout of August 14, 2003 has brought these two potential problems into visibility. First, alarm systems or state estimators could fail to notify the operator. Second, the re-dispatch or curtailment process may either not work properly due to bad data or too lengthy a communication process. Thus, to compensate for these potential factors, it may perhaps be necessary either to re-examine the definition of the operating limits, or to change the single-contingency criterion to a double-contingency criterion, or to a probabilistic reliability criterion. In any case, it is likely that this will result in the need for more transmission investment so as to provide the additional safety margin.

Further information about efforts to improve grid reliability in response to the dramatic increases in inter-regional bulk power transfers that have resulted from industry restructuring is presented in *Assessment Methods and Operating Tools for Grid Reliability: An Executive Report on the Transmission Program of EPRI's Power Delivery Reliability Initiative.* [Note: This report appears in Appendix 2: Additional Material for the Record.]

Q3. Are there areas where our standards development is inadequate and is there a federal role in funding the development of consensus standards organizations that work with your industry?

A3. Industry and government have a long history of working together closely with standards-making organizations, such as the Institute of Electrical and Electronic Engineers (IEEE). Recent work on the IEEE 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems provides an excellent example. The three-year effort has been fully supported by the power industry, EPRI, the U.S. Department of Energy, and other stakeholders.

This new standard establishes the technical foundation for the interconnection of all distributed energy resources (DER) with electric power systems. It ensures that major investments in DER technology development by the power industry and government organizations will result in real-world applications providing alternative sources of electric power to the electric utility operating infrastructure. The IEEE standard may be used in federal legislation and rule-making, in state PUC deliberations, and by more than 2,500 electric utilities in formulating technical requirements for interconnection agreements.

The efforts and commitment of the many stakeholders were instrumental in the fast-track success of the standard and in the implementation of the complementary 1547 body of standards-development activities. EPRI and numerous other organizations have hosted the meetings, and many companies have supported the participation of their employees. Altogether, the 1547 Working Group has involved more than 350 members. To further aid in the safe and reliable integration of DER with electric power systems, the Group is currently working on a series of ancillary standards related to testing (P 1547.1), applications (P 1547.2), and communications (P 1547.3).

Attachment A

Analysis of DER Applications Potential

Table 1 displays the results of EPRI's baseload electric, cogeneration and peaking DER power analysis. Almost all of the baseload electric/cogeneration potential is in the industrial sector and almost all applications are cogeneration. Peaking applications are expected only in the commercial sector and mainly comprise diesel engine generators.

Table 1
Summary of Results for Lowest Cost of Electric Power by DR Application (number of units)

Sector/	DR Size Range (kW)									
Operation Mode	30-74	75-149	150-299	300-599	600-999	1000-2499	2500-4999	5000-9999	10-20 MW	Total
Commercial										
Electric Only	440	696	465	392	56	437	11	1	0	2,497
Cogeneration	854	481	309	203	137	180	7	0	0	2,171
Peaking Power	35,206	13,503	6,591	3,120	1,378	527	100	0	0	60,425
Total Commercial	36,500	14,680	7,365	3,715	1,570	1,144	118	1	0	65,093
Industrial										
Electric Only	31	31	25	25	75	76	61	48	16	388
Cogeneration	10,605	9,997	9,746	9,822	5,687	4,811	2,327	1,285	657	54,937
Total Industrial	10,636	10,028	9,771	9,847	5,762	4,887	2,388	1,333	673	55,325
Total	47,136	24,708	17,136	13,562	7,332	6,031	2,506	1,334	673	120,418

Table 1 displays total national results that show that there are a total of 120 thousand potential applications of varying sizes. Results are also disaggregated by state and SIC: The top states, representing 38% of total applications, are California, New York and New Jersey. The top Standard Industrial Classifications (SICs) are 20/ Food and Kindred Products, 30/ Rubber and Miscellaneous Plastics Products, 34/ Fabricated Metal Products, and 28/ Chemicals and Allied Products. Although showing fewer applications than the top industrial SICs, the top commercial SIC, 54/ Food Stores, also shows significant potential.

Assumptions used in the above (base case) analysis are displayed in Tables 2 to 4.

Table 2
Generating Unit Parameters for Base Cases

Segment	Residential	Commercial	Industrial
Technology Type	PEM Fuel Cell	Microturbine	Reciprocating
Size (kW)	7	150	2,000
Packaged Cost ($/kW)	800	550	400
Installation Cost ($/kW)	200	250	200
Permitting ($/kW)	30	75	57
Interconnection ($/kW)	20	50	17.5
Cogen. Equip. Cost ($/kW)	N/A	N/A	150
Electric Efficiency	40%	30%	38%
Thermal Output (MMBtu/hr)	N/A	N/A	8.4
Overall Efficiency	40%	30%	85%
Variable O&M Expense ($/kWh)	.007	.004	0.007
Fixed O&M Expense ($/kW-yr)	20	20	7
Electric Capacity Factor	25%	50%	80%
Thermal Utilization Factor	0%	0%	70%

Table 3
Fuel and Backup Power Costs for Base Cases

Segment	Residential	Commercial	Industrial
Natural Gas Price ($/MMBtu)	6.82	5.47	2.77
NG Price Escalation Rate (%)	1.8	2.1	3.0
Backup Power Price ($/kW)	25	50	50
Backup Power Price Escalation Rate (%)	1.7	1.5	1.5

Table 4
Financial Parameters for Base Cases

Segment	Residential	Commercial	Industrial
Equity Fraction (%)*	0	0	0
Return on Equity (%)*	N/A	N/A	N/A
Interest Rate on Borrowed Money/Lease (%)	12	12	9
Discount to Customer (%)	0	0	0

ANSWERS TO POST-HEARING QUESTIONS

Responses by Thomas R. Casten, CEO, Private Power, LLC, Oak Brook, IL; Chairman, World Alliance for Decentralized Energy

Questions submitted by the Subcommittee on Energy

Q1. Which states or regions—or countries do a good job of supporting distributed generation? Why do you think this is?

A1. No U.S. state does a good job. New York, personally encouraged by Governor Pataki, has developed standard interconnection rules for very small DG and has started to address standby power. California, reeling from shortages and brownouts, has claimed support for DG and offers some avoidance of penalty rates for small DG.

However, several countries are doing a surprisingly good job in supporting DG. Portugal leads in leveling the playing field. The single national grid company is required to purchase DG under a formula that considers the avoided cost of central generation, the transmission capital saved by local generation, the transmission losses saved by DG, the impact of recycling heat from DG on pollution, and the availability of the DG. By contrast, no state in the U.S. gives any credit to the DG plant for any costs beyond avoided cost of central generation, ignoring the savings of T&D capital and losses and the pollution savings.

Indian regulators have had a recent epiphany, recognizing that the country is starved for power, has up to 50 percent losses in the grid (compared to 10 percent in U.S. on average) and that one of the country's major industries, sugar cane, could produce significant power without fossil fuel, saving imports and carbon emissions. One-year-old policies provide 13-year contracts for DG at full value and require the local grid to pay half of the costs of interconnecting with these local generators.

China, operating in a command and control mode, does not allow new factories to build boilers for thermal energy when there is a nearby power plant that can supply waste thermal energy. China increased power output over the prior decade by roughly 45 percent, but actually reduced CO_2 emissions by nearly 15 percent in the same decade by promoting more efficient DG.

In general, I think the public and its leaders accept the central generation paradigm without much thinking and the monopoly protected utilities, beneficiaries of the resultant practices, find it in their interest to maintain the laws and approaches that prevent more efficient, but competitive DG. When a polity comes under intense pressure, all assumptions come under question. New York lost industrial jobs and "enjoyed" nation leading high electric prices and began to change. California power crises caused thinking. Indian poverty finally toppled conventional wisdom.

Q2. What steps should the Federal Government take to allow distributed generation and combined heat and power to compete fairly?

A2.

- Reshape all debate to consider the delivered cost of power.
- Use antitrust laws to vigorously oppose state rules that limit private wires or otherwise prevent DG from competing to supply customers with electric power.
- Revamp EPA rules to focus on permit limits and allowance trading programs based on pollution per megawatt hour of useful electricity or thermal energy, applicable equally to all heat and power generation, eliminating all grandfather rules, legacy pollution permits and differences between types of plants and age of plants. This will reward efficiency and force the industry to build power plants close to users where thermal energy can be recycled.
- Focus research and development support on energy recycling technologies, which are inherently DG.
- Exercise federal jurisdiction over power regulation as the interstate commerce it truly is. This will lessen the power of local monopolies to preserve anti-competitive rules and should lead to more functional markets.

Questions submitted by Minority Members

Q1. What future role do you see for the national laboratories in helping to fulfill your goal of building more local power, building smaller units and recycling waste energy? Are there specific programs in the laboratories that should be better funded or redirected to produce the needed technologies?

A1. There has been very little work done by industry or the labs on the technologies that recycle low-density waste energy. Industry rejects vast quantities of exhaust heat that does not support economical electric generation with conventional Rankine cycle steam plants, but which has higher quality than the typical geothermal field. Technology does exist (organic fluid Rankine cycle) to recycle this heat. Small technical improvements would help economics.

The proof of feasibility for recycling can be found in a typical geothermal field. A California geothermal project described by LBL taps thermal energy from the ground to produce 40 megawatts of electricity. A 250-megawatt coal fired power plant exhaust contains the same quantity and quality of energy in its exhaust, and could, using current organic fluid Rankine cycle generation, produce an added 40 megawatts with no added fuel. Without the subsidies received for "renewable" energy by the geothermal installation and using today's technology, it has not made economic sense to recycle coal exhaust. The labs could work on increasing the efficiency and capital efficacy of low temperature recycling, which would lead to myriads of DG plants wherever factories exhaust waste heat.

The labs, especially LBL, have documented some of the potential to recycle waste energy from U.S. industry and gathered information about how other more efficiency focused societies do a better job of recycling energy from steel, primary metals, foundries, glass production, etc. The results are in obscure technical papers that never reach policy makers or the general public. The labs could popularize this information to great advantage.

Q2. You list as one of your approaches (page 4) to finding solutions the need for standardized interconnection access for distributed energy sources.

A2. There are, according to DOE, over 6,000 DG plants that supply nine percent of U.S. energy, all of which are interconnected with the grid. Yet, every new DG plant proponent, with the exception of a few very small plants that fall under standard rules in Texas, NY, and Massachusetts must go through extensive hearings and subject their designs to individual approval by the local utility, which has financial incentive to prevent the existence of a new competitor. These hearings are filled with dire warnings of the dangers to the utility workers and suggestions that without extraordinary prudence, the DG plant could trip the entire grid. Yet, to my knowledge, there are no known cases of utility workers being electrocuted by DG plants or of DG plants causing grid failure. In fact, the connection of a one-megawatt electric motor has nearly the same impact on the grid as a one-megawatt generator. For the motor, there are national standards, incorporated in local codes, and no hearing is needed. For the generator, the process could take up to 18 months and a great deal of money. DG will not improve U.S. standards of living or reduce U.S. fuel use and pollution until there are national standards for interconnection of all sizes of DG.

Q3. What are the unresolved technical issues associated with standardized interconnections? Do new technologies need to be developed to ensure that these interconnections will function more safely and seamlessly?

A3. In private conversations, the utility personnel assigned to interconnection debates admit that there are no major technical issues, only commercial issues. Change the rules to make the utility operating the distribution grid embrace efficiency and energy recycling, and the interconnection technical issues will all go away. See above regarding over 6000 installations, per DOE, and add the unnoticed 100,000 back pressure turbines that generate electricity in parallel with the grid (industry data). It is common for the utility community to insist that there are great and deep technical issues, because legally trained regulators lack the confidence to overrule utilities on safety issues.

The new technologies most in need of development are hybrid direct current supply systems for computer intensive users, and the control technology needed to blend on-site power with grid backup to increase the reliability of power from its present state, which was designed for the industrial motor requirement, to today's needs for power quality by computers and servers. These technologies, as already deployed, start with any type or quality of incoming power, invert that power to DC and then prepare conditioned alternating current. Advances in direct current distribution and control will make DG the obvious economic choice and move the focus away from unfounded safety issues to very real economic and efficiency concerns.

Appendix 2:

Additional Material for the Record

EPRI

Assessment Methods and Operating Tools for Grid Reliability

An Executive Report on the Transmission Program of EPRI's Power Delivery Reliability Initiative

Product ID # 1001408

Final Report, February 2001

EPRI Project Manager
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Technical writers Steve Hoffman of Hoffman Publications, Inc., and Jonas Weisel wrote this final report and—together with John Douglas—wrote a variety of articles, presentations, and summaries of the Initiative. North American Electric Reliability Council (NERC) staff who lent their advice and expertise to the Initiative included Bob Cummings and Lou Leffler. The Reliability Initiative Executive Committee included: Past Chairperson: Bruce Renz, American Electric Power (AEP); Chairperson: Bill Donohue, Consolidated Edison Company; Transmission Program Chairperson: Mike Greene, TXU Electric; Ricky Bittle, Arkansas Electric Coop; Terry Boston, Tennessee Valley Authority (TVA); George Dolinsky, Public Service Electric and Gas (PSE&G); Nicolas Lizanich, UCM; Bernard Pasternack, AEP; and Michehl Gent, NERC.

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REPORT SUMMARY

Maintaining a high level of power grid reliability is one of the most pressing issues facing the electric power industry today. This report summarizes the achievements and planned activities of the transmission portion of the industry-wide Power Delivery Reliability Initiative, which is developing new tools and methods for assessing and improving grid reliability.

Background

The North American power system today is increasingly being stressed as a result of sweeping changes in the electric power industry. Dramatic increases in interregional bulk power transfers due to industry restructuring and a growing complexity in market transactions are causing the grid to be used in ways for which it was not originally designed. The strain on the system is manifesting itself in more frequent wide-area power disturbances and outages. In response, in late 1999, EPRI launched the Power Delivery Reliability Initiative—a multi-year effort aimed at addressing the challenge of maintaining electric power system reliability throughout North America during industry restructuring.

Objectives

- To identify underlying problems in the power grid, and improve reliability/risk assessments of transmission grids.
- To develop new tools to improve system reliability.

Approach

Phase I of the project extended from the fall of 1999 through April 2001. In Phase I, the project team conducted a preliminary assessment of the status of the North American grid through an analysis of North American Electric Reliability Council (NERC) regional reliability reports. To improve assessments of grid reliability, the team developed a Probabilistic Reliability Assessment (PRA) methodology that calculates a measure of the probability of undesirable events and a measure of the severity or impact of the events. The PRA was demonstrated in three proof-of-concept demonstration studies in the Southern Control Area of the Southeastern Electric Reliability Council (SERC), the American Electric Power (AEP) transmission system, and the Eastern Interconnection. To improve grid reliability, the project team developed two new operating tools—the Real-time Security Data Display (RSDD) and the Tag Dump program. The project team synthesized information from Initiative meetings and reports to prepare this executive report on the Reliability Initiative. In Phase II of the Initiative, which will extend from

April 2001 to December 2002, the project team will develop an on-line contingency analysis program and risk monitor; provide enhancements to the PRA methodology, RSDD, and Tag Dump; support NERC activities to enhance interregional coordination; and develop a two-way data link to improve the interface between the transmission grid and nuclear plants.

Results

This report describes work completed to date in Phase I of the Initiative, outlines planned activities and the expected value of those efforts in Phase II, and summarizes recommendations suggested by industry representatives for improving the reliability and efficiency of the North American power grid. In Phase I, the PRA provided the means to identify the most critical potential grid failures, evaluate their adverse impacts, and recommend effective mitigation alternatives. The regional studies identified the value and limitations of the PRA methodology in studies of large control areas, demonstrated the PRA to be a feasible and practical tool for reliability assessment, and enabled the regions to identify areas of grid congestion, determine root causes, and evaluate the effectiveness of mitigation plans. The RSDD afforded security coordinators with a graphical, bird's-eye view of reliability over a wide region—up to the entire North American grid. The Tag Dump software presented power system operators and planners with aggregated schedules of wholesale power transactions between control areas or between security coordinators, enabling security coordinators to perform hour-ahead operational studies and plan for their current-day operation. In Phase II, the on-line contingency analysis and risk monitor will give operators the tools to conduct real-time assessments of critical contingencies and determine the best course of action. Enhancements to the PRA methodology will increase the program's accuracy and applicability. Enhancements to the RSDD and Tag Dump will provide operators better tools to view interconnection-wide power flows and compute the impact of transaction schedules. Tools and data developed to improve interregional coordination will help solve critical seams issues between regions of the North American grid. An on-line risk monitor will enable grid operators and nuclear plant operators to exchange real-time information on grid reliability and plant availability. Recommendations that industry representatives suggested include an array of possible efforts to improve grid reliability and market efficiency by improving existing planning and operations tools, as well as developing advanced new tools.

EPRI Perspective

EPRI's Power Delivery Reliability Initiative demonstrates the industry's continuing commitment to ensuring high levels of reliability, and will provide critical insight for broader industry-government efforts. For the short term, the Initiative is providing tools that energy companies can use immediately to avoid further widespread outages. In the long term, the Initiative is targeting corrective actions and investments required to guide technology development for enhanced reliability. Also, by addressing concerns over electricity reliability performance, the Initiative is helping energy companies and the industry as a whole form policy decisions and minimize public apprehension. To achieve these objectives, the Initiative established two separate, but parallel, programs—one to address reliability on the transmission grid, and the other to focus on reliability improvements for distribution systems. On the transmission side, the Initiative's Transmission Program sought to improve reliability/risk assessments of transmission grids and to develop new operational tools to improve system reliability. The Initiative's Distribution Program analyzed five representative systems, created the first industry-wide "best practices" knowledge base, and developed a self-audit template for companies to evaluate their own system and practices.

Keywords

Power system operation

Power system planning

Regional reliability

Reliability

Risk assessment

Transmission grid

ABSTRACT

To address the growing challenge of maintaining electricity reliability, in late 1999, EPRI launched a major new initiative. The Power Delivery Reliability Initiative is a multi-year, utility-funded program to understand the root causes of recent power outages, identify underlying problems in utility systems, and recommend ways to improve system reliability. To achieve these objectives, the Initiative established a Transmission Program and a Distribution Program. This report summarizes the accomplishments of Phase I of the Transmission Program—which extends from the fall of 1999 through April 2001—and outlines the deliverables planned for Phase II—which extends from April 2001 through December 2002.

The Initiative's Transmission Program sought to improve reliability/risk assessments of transmission grids, and to develop new operational tools to improve system reliability. In Phase I, to improve assessments of grid reliability, the team developed a Probabilistic Reliability Assessment (PRA) methodology that calculates a measure of the probability of undesirable events and a measure of the severity or impact of the events. Initiative members then demonstrated the PRA in three proof-of-concept demonstration studies in the Southern Control Area of the Southeastern Electric Reliability Council (SERC), the American Electric Power (AEP) transmission system, and the Eastern Interconnection.

To provide tools to improve grid reliability, the project team developed two new operating tools—the Real-time Security Data Display (RSDD) and the Tag Dump program. The RSDD afforded security coordinators with a graphical, bird's-eye view of reliability over a wide region—up to the entire North American grid. The Tag Dump software presented power system operators and planners with aggregated schedules of wholesale power transactions between control areas or between security coordinators, enabling security coordinators to perform hour-ahead operational studies and to plan for their current-day operation.

In Phase II of the Initiative, the project team will develop an on-line contingency analysis program and risk monitor; provide enhancements to the PRA methodology, RSDD, and Tag Dump; support NERC activities to enhance interregional coordination; and develop a two-way data link between the transmission grid and nuclear plants. These tools will give system operators new on-line, real-time capabilities to conduct better assessments of critical contingencies and determine alternative courses of action, improve the accuracy of the PRA methodology, add new capabilities to the RSDD and Tag Dump programs, help solve critical seams issues, and improve the interface of the grid with nuclear plants.

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1 EXECUTIVE SU MMARY

The North American power system today is increasingly being stressed as a result of sweeping changes in the electric power industry. Dramatic increases in interregional bulk power transfers due to industry restructuring and a growing complexity in market transactions are causing the grid to be used in ways for which it was not originally designed. The strain on the system is manifesting itself in more frequent wide-area power disturbances and outages.

In response, in late 1999, EPRI launched the Power Delivery Reliability Initiative—a multi-year effort aimed at addressing the challenge of maintaining electric power system reliability throughout North America during industry restructuring. The Initiative was undertaken on behalf of the U.S. electric power industry and at the request of energy companies, the North American Electric Reliability Council (NERC), the Association of Edison Illuminating Companies, the IEEE Power Engineering Society, the Edison Electric Institute (EEI), and other organizations. Participants in either the transmission or distribution (or both) portions of the Initiative now number 47 members.

The goals of the Initiative are to understand the root causes of recent power outages, identify underlying problems in power systems, and develop tools to improve system reliability. To achieve these objectives, the Initiative established two separate, but parallel, programs—one to address reliability on the transmission grid, and the other to focus on reliability improvements for distribution systems.

Phase I of the Initiative began with the project's launch in late 1999 and will be complete in April 2001. With strong encouragement from funders, EPRI is extending the Initiative into Phase II. This phase will begin in April 2001 and extend approximately 15-18 months until October 2002 (see Figure 1-1).

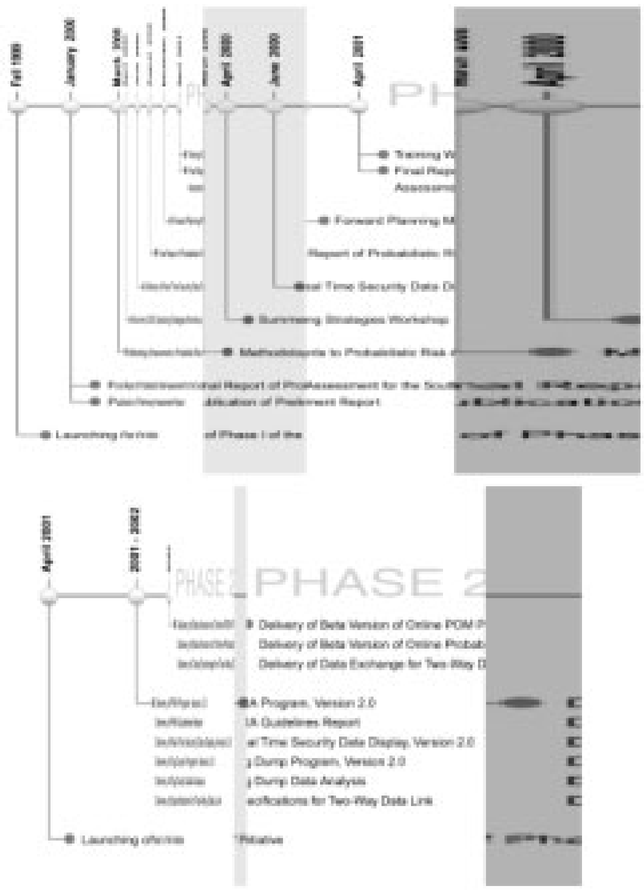

Figure 1-1 Timeline of Power Delivery Reliability Initiative

Section 1 of this report provides a brief summary of the Transmission Program of the Power Delivery Reliability Initiative. It reviews the specific accomplishments of Phase I, recalls the discussions and decisions from the Forward Planning Meeting in December 2000, outlines the deliverables planned for Phase II, and explains the organization of this report.

Phase I

Phase I of the Transmission Program set two goals. The first objective was to improve reliability/risk assessments of transmission grids. This involves the first comprehensive effort to conduct assessments of power grids that includes the probability of failure. The second objective in Phase I was to develop new near-term tools to improve system reliability. These tools were designed to meet critical needs for the summer of 2000.

Participants in the Reliability Initiative are benefiting from the following Phase I accomplishments:

- **New assessment methods** that determine the risk of generator and grid failure, evaluate the impact of these failures, and recommend alternatives to enhance system reliability.
- **New on-line operating tools**, developed in record time to help meet summer 2000 needs, which enable security coordinators to monitor interconnection-wide, real-time information on key power flows, bus voltages and transaction schedules to avoid bottlenecks and ensure wide-area system reliability.

Further, participants are realizing the following benefits:

- **Greater ability to prevent cascading outages and more secure wide-area operation** that supports a rapidly growing wholesale power market.
- **Cooperation among industry interests** and a pooling of resources to achieve benefits of mutual interest and pave the way for future collaborations.

The Phase I accomplishments and their value are described below (also see Table 1-1).

Table 1-1 Phase I Accomplishments

Deliverable	Date Delivered	Value
Report: Power Delivery Reliability Issues: The Challenge	January 2000	Established baseline, and focused development of new tools and methods.
Report: Probabilistic Risk Assessment for the Southern Control Area in SERC	January 2000	Demonstrated ability of methodology to identify bottlenecks, identified limitations, and illustrated potential value of real-time risk monitoring system.
Report: Application of Probabilistic Reliability Assessment to a Part of the AEP System	August 2000	Confirmed and quantified voltage problems and constraints, provided framework for displaying geographical spread of impacts, and showed promise of probabilistic reliability margin.
Report: Probabilistic Reliability Assessment of the Eastern Interconnection	April 2001	Will provide thorough testing of PRA methodology, data, and software; demonstrate zone definitions; and establish starting point for follow-on studies.
Physical and Operational Margin (POM) Program	April 2001	Will provide second generation tool for funders to conduct contingency analyses.
Probabilistic Reliability Index (PRI) Program	April 2001	Will provide second generation tool for funders to calculate risk indices of overload and voltage security.
Summer 2000 Operating Strategies Workshop	April 11, 2000	Offered forum for reviewing problems of summer 1999, and identifying tools and strategies for summer 2000.
Real Time Security Data Display	June 2000	Supports better coordination between control area operators and security coordinators.
Tag Dump Program	June 2000	Improves power flow management on a control-area-to-control-area basis.
Coordination between EPRI and NERC	Ongoing	Provides focus, avoids duplication of efforts and supports pooling of resources.

Coordination with Nuclear Power Industry	Ongoing	Improves interface between grid and nuclear facilities.
Coordination Between System and Market Entities	Ongoing	Supports efforts to maintain secure system operation and efficient market operation.
Executive Report: Assessment Methods and Operating Tools for Grid Reliability	February 2001	Summarizes achievements of Phase I and outlines work planned in Phase II.

Accomplishments in Phase I

Preliminary Assessment of the North American Grid

In late 1999, EPRI developed a report entitled *Power Delivery Reliability Issues: The Challenge.* This report, published in January 2000, constituted an executive-level, preliminary assessment of the status of the North American grid through an analysis of NERC regional reliability reports.

Value: By summarizing information on recent power outages and compiling available analyses of grid reliability in 10 regions of the North American grid, the report helped focus the development of new tools and methods on areas of greatest need and with the highest potential for grid reliability enhancement.

Probabilistic Reliability Assessment (PRA)

The PRA methodology, developed in Phase I, offers energy companies a more accurate tool for assessing grid reliability under deregulated market conditions. Unlike traditional deterministic contingency criteria, PRA calculates a measure of the probability of undesirable events and a measure of the severity or impact of the events.

Value: Initiative efforts proved the PRA to be a practical assessment method, and fostered a greater awareness and acceptance of PRA among planners and operators. Work in Phase I also included significant preparatory work toward development of an on-line risk monitor, which will be completed in Phase II.

The PRA provides the means to identify the most critical potential grid failures, evaluate their adverse impacts, and recommend effective mitigation alternatives. It also allows grid planners to assess the tradeoffs between the probability of a contingency occurring and the cost of operational changes to avoid those contingencies.

- **Proof-of-Concept Regional Studies.** Studies of the practical application of the PRA method were conducted for two portions of the North American grid—the Southern Control Area of the Southeastern Electric Reliability Council (SERC) and the central Ohio area of the

American Electric Power (AEP) transmission system. Studies are under way and will be completed during Phase I for the Eastern Interconnection.

Value: The system studies identified the value and limitations of the PRA methodology in studies of large portions of the transmission network, demonstrated the PRA to be a feasible and practical tool for reliability assessment, helped ensure that the PRA tools are developed to meet specific regional needs, and enabled the regions to identify areas of grid congestion, determine root causes, and evaluate the effectiveness of mitigation plans. The studies also demonstrated the feasibility and value of a real-time probabilistic risk monitoring system.

- **PRA Software Programs.** Two software programs were developed and made available to funders. The Physical and Operational Margin (POM) program quickly performs security calculations that provide a quantitative impact of every contingency on system conditions. The Probabilistic Reliability Index (PRI) program calculates overall risk indices of overload and voltage security for various zones of a wide-area system.

  Value: These software tools will allow users to conduct their own reliability assessments in order to identify transmission bottlenecks and develop mitigation measures.

Near-Term Operating Tools for Enhancing the Security of the North American Grid

- **Atlanta Workshop.** A workshop in Atlanta in April 2000 assembled North American security coordinators to discuss summer 2000 operating strategies.

  Value: The workshop made available a forum for reviewing problems from the summer of 1999, predicting problems likely to arise in the summer of 2000, describing tools and procedures already planned, and identifying recommendations for operating procedures and coordination for summer 2000 operations.

- **Real Time Security Data Display (RSDD).** The RSDD affords security coordinators with a graphical, bird's-eye view of reliability over a wide region—up to the entire North American grid. Widely regarded as a "just-in-time" valuable tool, RSDD provides the web-based capability to display voltage values and limits for about 300 critical buses, together with the congestion status and amount of power flow for about 50 "flowgates," representing critical lines or set of lines that require close monitoring.

  Value: RSDD allows for better coordination between control area operators or security coordinators and improved interconnection-wide system reliability.

- **Tag Dump.** The "Tag Dump" software presents power system operators and planners with aggregated schedules of wholesale power transactions between control areas or between security coordinators, enabling security coordinators to perform hour-ahead operational studies and to plan for their current-day operation. Praised for its practical usefulness and timeliness, the software also supplies useful data for calculating more accurate Available Transfer Capacities (ATC) to post on the Open Access Same Time Information System (OASIS) for market reservation.

  Value: This software improves power flow management on a control-area-to-control-area basis, reduces grid congestion, and helps avoid grid failures.

Convergence of Efforts

- **EPRI/NERC.** EPRI and NERC worked together in conceptualization of the Reliability Initiative, definition of key products, and garnering of industry support.

  Value: Coordination of EPRI and NERC efforts avoids duplication of effort and supports cooperation and a pooling of resources to achieve benefits in areas of mutual interest.

- **Nuclear Power Industry.** Nuclear power experts provided consultation to the Initiative for development of probabilistic risk assessment methods, design of an on-line risk monitor for the transmission grid, and the interface of this monitor with nuclear risk meters. Initiative representatives made presentations to the Nuclear Regulatory Commission (NRC).

  Value: Expert consultation and discussion with representatives of the nuclear industry applies nuclear power's long experience with risk assessment methods and monitors to the design of the Initiative's tools and improves the interface between grid and nuclear risk monitors.

- **Grid Market Operations.** Initiative representatives made presentations to the NERC Market Interface Committee (MIC) and the Western MIC, and the Initiative received MIC endorsement.

  Value: Coordination between system and market operation entities helps ensure that Initiative efforts address the need to maintain secure system operation and enable efficient market operation.

Final Report

This final report of Phase I of the Transmission Program of the Power Delivery Reliability Initiative summarizes the overall achievements of the Initiative to date—including development of methods for better assessing the reliability of the North American grid, application of these methods in several regions, and development of operating tools for improving real-time systems operations in the short term. The report also outlines recommendations for follow-on Phase II tasks.

Value: The report provides a synthesis of the accomplishments and value of the Initiative's efforts in Phase I and a guide to planned work in Phase II.

Forward Planning Meeting of the Transmission Program

A meeting conducted December 5-6, 2000, in New Orleans assembled principal funders of the Transmission Program to review current progress of the Initiative and to chart the course of future research. The sessions devoted to reporting project status included presentations on results of the AEP PRA and the methodology and early results of the Eastern Interconnection PRA.

Sessions focused on planning Phase II efforts included round-table discussions and breakout group meetings. These activities resulted in a list of key accomplishments in Phase I and a prioritized list of tools needed in Phase II—from both planning and operations perspectives. Tools that participants requested for Phase II included the following:

- An on-line contingency analysis program and an on-line risk monitor
- Enhancements to the PRA methodology
- Enhancements to RSDD and Tag Dump
- Products in support of NERC activities to enhance interregional coordination
- Technologies for exchange of real-time information with nuclear plants.

Phase II

Phase II of the Transmission Program will focus on developing the tools requested by Initiative funders. Initiative participants will realize the following benefits from projects proposed for Phase II:

- **Reduced frequency and severity of outages** via application of new capabilities for on-line, real-time assessment of potential grid failures.
- **Increased operating flexibility** made possible by tools that enable a better understanding of tradeoffs involved in various operating strategies.
- **Improved grid reliability planning** through better guidance on input data for PRA analysis and new PRA features for must-run units and operating procedures.
- **Increased grid reliability** via RSDD and Tag Dump enhancements that provide security coordinators additional data on interregional power flows and new features for more automated, interconnection-wide transaction scheduling.
- **Improved interregional coordination** through analysis of historical data on an interregional basis and advancement of NERC activities.
- **Enhanced grid reliability and nuclear plant safety** via real-time exchanges of risk indices between grid and plant risk meters.

The proposed projects for Phase II and their value are further described below (also see Table 1-2).

Table 1-2 Phase II Proposed Tasks

Deliverable	Delivery Date	Value
On-line Physical and Operational Margin (POM) Program	2002	Simulate real-time critical contingencies, and identify effective mitigation measures.
On-line Probabilistic Reliability Margin (PRM) Program	2002	Improve understanding of tradeoffs involved in system operation under a variety of conditions.
PRA Program, Version 2.0	2001-2002	Improve congestion management and system reliability through increases in program's accuracy and applicability.
PRA Guidelines	2001-2002	Promote uniformity in PRA data and application of the methodology.
PRA Users Group	2001-2002	Share lessons learned, and compare problem-solving approaches.
RSDD Version 2.0	2001-2002	Improve decision making through more accurate indication of current conditions.
Tag Dump Program, Version 2.0	2001-2002	Improve scheduling of wholesale transactions through enhanced display of information and automated analysis.
Tag Dump Data Analysis	2001-2002	Enable Regional Transmission Organizations (RTOs) to better conduct planning.
Planning and Operating Standards	2001-2002	Improve analysis through more uniformity in data collection and reliability indices.
Support for CIM	2001-2002	Improve cross-platform data sharing.
NERC Activities	2001-2002	Provide tools to solve critical seams issues.
Two-Way Data Link	2001-2002	Improve interface of grid with nuclear plants.

Proposed Projects in Phase II

On-line Contingency and Probabilistic Reliability Monitor

- **Physical and Operational Margin (POM) Program.** The POM will be implemented on-line as a fast contingency analysis program.
- **Probabilistic Reliability Monitor (PRM).** A PRM will be developed that combines on-line versions of POM and PRI to provide real-time Probabilistic Reliability Indices.

  Value: Potential grid failures will be reduced as a result of the new on-line, real-time capabilities provided to system operators, including the ability to conduct better assessments of critical contingencies and determine the best course of action. In addition, the PRM will help operators understand the trade-offs involved in operating their transmission systems under a variety of conditions—thus allowing energy companies to develop new business practices and products tailored to the deregulated market.

PRA Enhancements and Implementation

- **PRA Program, Version 2.** Enhancements to the PRA software will include a sensitivity analysis of outage data, consideration of operating procedures, identification of must-run units, and other features.
- **PRA Guidelines.** PRA guidelines will be developed, including standards for how the analysis is calculated and the kind of data needed. Also, a numerical index will be developed for a reference level of reliability.
- **PRA Users Group.** A user group will be established to share lessons learned, compare problem-solving approaches, and promote use of the methodology.

  Value: Improvements to the PRA will increase the program's accuracy and applicability, provide additional information to planners, and promote a uniform methodology for grid planning. Together, these enhancements will help planners improve regional grid reliability.

Enhancements of RSDD and Tag Dump

- **RSDD Version 2.** RSDD software enhancements will include display of additional data (e.g., reactive reserves and PRM indices), improved graphics, and an operator-friendly user interface.
- **Tag Dump Program Version 2.** Tag Dump software enhancements will consist of new capabilities to interface with electronic schedules, display more flexibly-defined bubble diagrams, and better integrate with other applications (e.g., POM and RSDD). The Tag Dump will also be improved to automate analysis of scheduling data, enable Tag Dump on an interconnection level, and allow coordination of tag schedules with flow-based schedules.

  Value: These software upgrades will provide security coordinators better tools for optimizing grid performance and stability by improving their ability to view interconnection-wide power flows and compute the impact of transactions schedules.

Tools and Data to Improve Interregional Coordination

- **Tag Dump Data Analysis.** A report will document analysis of historical tag dumps and transmission loading relief on an interregional basis.
- **Planning and Operations Standards.** EPRI will provide information to NERC for use in proposing standards for planning and operation (e.g., in the use of PRA).
- **Support for CIM.** In areas relevant to the Initiative, EPRI will promote use of the Common Information Model (CIM) for interregional coordination.
- **NERC Activities.** EPRI will support NERC activities related to the Initiative, including development of a Real-Time Topology through the ISN, a power flow database system, a master ID naming standard, and the Flow-Based Study Tool (FIST).

  Value: Together, these efforts will help solve critical seams issues between regions, contributing to the improvement of real-time reliability of the North American grid.

Improved Interface with Plant Operators

- **Two-Way Data Link.** The RSDD will be provided with an interface to exchange real-time information with nuclear plants on grid reliability indices and plant availabilities. An on-line risk monitor will be developed that automatically sends data on risk levels at voltage buses to nuclear plants and reviews indices of nuclear plant risk levels.

  Value: These tools will improve the operational security of the transmission grid and the efficient, safe operation of nuclear plants.

Charting a Course for Improving Grid Reliability

In addition to the Power Delivery Reliability Initiative, EPRI supports broad-based efforts throughout the electric power industry to improve the operation and reliability of the North American power grid. The Electricity Technology Roadmap has given direction and structure to these efforts. One portion of this EPRI-sponsored collaborative program has established goals and research programs designed to ensure the increased reliability and carrying capacity of the North American power grid.

In the past year and a half, to achieve the goals articulated in the Roadmap, representatives from throughout the power industry have proposed recommendations for future work in grid operations and planning. These recommendations originated across the full spectrum of industry interests. They were proposed in meetings that assembled a wide cross-section of industry representatives from energy companies, RTOs and independent system operators (ISOs), government agencies, research institutes, and trade organizations. Meetings included the following EPRI-sponsored workshops:

- EPRI-led focus groups held in Atlanta on June 7, 1999 and in San Diego on February 7, 2000
- The Summer 2000 Operating Strategies Workshop held in Atlanta on April 11, 2000

- An RTO/ISO Workshop held in Holyoke, Massachusetts on October 23, 2000
- The Forward Planning Meeting of the Power Delivery Initiative held in New Orleans on December 5–6, 2000
- Meetings of the Steering Committee of the Power Delivery Initiative.

In addition, a number of these recommendations have been outlined in several reports, including *Issues and Solutions: North American Grid Operations and Planning (2000-2005), Probabilistic Risk Assessment for the Southern Control Area in SERC*, and *Application of Probabilistic Reliability Assessment to a Part of the AEP System.*

The recommendations cover an array of issues. They seek to improve grid reliability and market efficiency by improving existing planning and operations tools, as well as developing advanced new tools. The recommendations address the wider area interconnection or "seams" issues, aiming to improve transactions and information exchange between regions. They also suggest methods and tools for data standardization to enhance the efficiency and security of the information network. In addition, a number of recommendations extend beyond energy company efforts to regulatory and institutional efforts that could improve market operations.

Section 12 of this report lists and discusses recommendations relevant to grid reliability that have been proposed in recent months. Table 1-3 below briefly lists eight categories of these recommendations and shows how these categories address relevant goals of the Electricity Technology Roadmap. The recommendations are presented here for consideration by industry interests and to help to set an agenda for future endeavors aimed at improving the reliability of the North American power grid.

Table 1-3 Recommendations for Improving the Reliability and Efficiency of the North American Power Grid

	Goals of Electricity Technology Roadmap Relevant to Grid Reliability and Efficiency					
Recommendation Categories	**Enhance Grid Reliability**	**Increase Carrying Capacity**	**Improve Market Efficiency**	**Guarantee Integrity and Availability of Information Network**	**Enhance Inter-regional Coordination**	**Balance Public and Private Interests**
PRA	X	X	X		X	X
Security Tools	X		X	X	X	X
Planning Tools	X	X	X		X	X
Seams Issues	X	X	X		X	X
Data Standardization and Exchange	X		X	X	X	X

	Goals of Electricity Technology Roadmap Relevant to Grid Reliability and Efficiency					
Recommendation Categories	Enhance Grid Reliability	Increase Carrying Capacity	Improve Market Efficiency	Guarantee Integrity and Availability of Information Network	Enhance Inter-regional Coordination	Balance Public and Private Interests
Countering Threats				X	X	X
Regulatory/Institutional	X		X		X	X
Human Resources	X		X			X

Purpose and Organization of This Report

This report summarizes the achievements of the Initiative in Phase I and outlines the planned future direction of the Initiative in Phase II (see Figure 1-2).

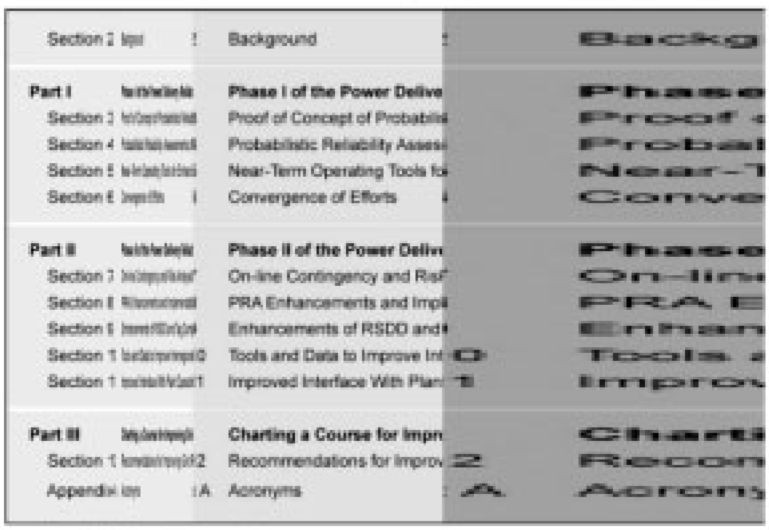

Figure 1-2 Report Organization

Section 2 provides background on the Initiative, reviewing the circumstances and events that led to the establishment of the Initiative and briefly describing its objectives and scope.

Sections 3 through 6 describe the key accomplishments in Phase I, including proof-of-concept of the PRA methodology, PRAs of regions of the North American grid, two near-term operating tools (RSDD and Tag Dump), and convergence of efforts by other industry groups and industry areas.

Sections 7 through 11 describe the key tasks planned in Phase II, including on-line contingency and risk monitoring tools, enhancements to PRA, enhancements to RSDD and Tag Dump, data and tools for interregional coordination, and tools for improved interface between the grid and nuclear plants.

Section 12 lists recommendations suggested by industry representatives for improving the reliability and operation of the North American power grid.

Appendix A defines acronyms used in this report.

2 BACKGROUND

Introduction

Section 2 reviews the history and issues that have led to the establishment of the Power Delivery Reliability Initiative. It describes the circumstances and events in the electric power industry in the 1990s, largely associated with the emergence of electricity industry restructuring, that have threatened system reliability and brought about the need for new tools and methods. The section also provides a brief overview of the Initiative, including its objectives, scope, and timetable of accomplishments.

Historical Perspective

The North American electric utility industry has long prided itself on its record of reliable delivery of electric power to its customers. However, in the 1990s, as the industry underwent fundamental restructuring, its ability to maintain reliable service has been severely challenged.

Increased Power Flows

One culprit has been unexpected power flows. As local markets have been opened to outside competition, the power industry has witnessed dramatic increases in the volume of interregional bulk power transfers. In the past four years, transaction volume in several NERC control areas has increased by more than 400%. In 1997, in the United States, an estimated 200,000 electricity transactions were conducted; in 2000, that total exceeded 1.5 million. Some large energy companies now participate in as many transactions in an hour as they used to conduct in a day. In addition, a strong economy has driven peak demand and energy consumption growth rates far beyond those initially projected.

At the same time, the growth of the electric power infrastructure has slowed. Neither generation capacity additions nor transmission line additions are keeping up with demand. While electric load grew by 35% in the 1990s, capacity was expanded by only 18%. Also, supplying adequate reactive power to support line voltage has now become a problem for both transmission and distribution companies.

Beyond the volume of new power flows, the power system has also experienced an increasing diversity of transactions. The new power flows, patterns, and magnitude have added significant and unpredictable complexity to the power delivery system in ways that the system was not designed to handle. The North American transmission grid, largely completed and in place by the 1970s, was designed to ensure reliability in a regulated marketplace, not to respond to the explosive growth and new procedures that have accompanied industry restructuring.

The most visible evidence of these problems has been an increase in power outages, emergency alerts, market volatility, and price spikes. Power disturbances rose sharply between 1996 and 1998, shortly after restructuring legislation took force. In 1999, several highly publicized urban outages occurred in New York and Chicago, and power outages and voltage declines struck the New England, Mid-Atlantic, and South Central states.

DOE POST Report

To address the issue of reliability on a federal level, the Department of Energy (DOE) in late 1999 brought together a team of experts to study the power disturbances that had occurred during the summer of that year. The team—the Power Outage Study Team, or POST— consisted of experts from DOE, the national laboratories, and the academic community. The study examined six power outages and two power disturbances that took place in various parts of the country between early June and early August 1999. Information was compiled through site visits, interviews with system operators, and public workshops.

In March 2000, the POST team issued a final report entitled *Report of the U.S. Department of Energy's Power Outage Study Team: Findings and Recommendations to Enhance Reliability from the Summer of 1999*. The report provided an analysis of the 1999 events and recommended actions that the federal government could take to help avoid future outages and disturbances. The team concluded that the studied outages "demonstrate that the necessary operating practices, regulatory policies, and technological tools for dealing with the [restructuring] changes are not yet in place to assure an acceptable level of reliability." The report further noted, "The development of reliability management reforms, tools, technologies, and operating procedures has lagged behind economic reforms in the electric industry. . . . The overall effect has been that the infrastructure for reliability assurance has been considerably eroded."

Recommendations of the POST report included the following:

- Promotion of market-based approaches to ensure reliable electric services
- Removal of barriers to distributed energy resources
- Support for mandatory reliability standards for bulk power systems
- Enhanced emergency preparedness activities for low-probability, high-consequence events on bulk-power systems
- Increased federal investments in electric reliability R&D
- Comprehensive assessments of electric power vulnerabilities.

In 2000, threats to system reliability continued. In May, an unexpected heat caught many energy companies with equipment out of service for scheduled maintenance, causing some companies to reduce voltages and curtail service to interruptible customers. In June, the California Independent

System Operator (ISO) was forced to initiate rolling blackouts across the San Francisco Bay area, and rising prices led to an almost doubling of average electricity bills in San Diego. Late in the year, California was again the focus of national attention when the state's power reserves fell below 1.5% of the load on the system. In response, the California ISO issued an unprecedented series of emergency Stage 3 alerts—actions normally occurring only during extreme summer peak loads, and applied rotating blackouts in Northern California.

EPRI Power Delivery Reliability Initiative

To address the growing challenge of maintaining electricity reliability, in late 1999, EPRI launched a major new initiative. The Power Delivery Reliability Initiative is a multi-year, utility-funded program to understand the root causes of recent power outages, identify underlying problems in utility systems, and recommend ways to improve system reliability.

Scope and Goals

EPRI undertook the Initiative on behalf of the electric power industry and at the request of energy companies, NERC, and IEEE. Forty-seven North American energy companies are providing funding for the Initiative. Also participating are representatives from EEI and other trade organizations. The Transmission Program of the Initiative has 37 members (see Table 2-1.)

Table 2-1 Members of the Transmission Program of the Power Delivery Reliability Initiative

Alliant Energy Corporation	Duke Energy	New York Power Authority
Ameren Services Co.	Entergy Corporation	Northeast Utilities
American Electric Power Service Corp.	Florida Power & Light Co.	Northern States Power Co.
Arkansas Electric Cooperative Corp.	Great River Energy	OG&E Electric Services
Baltimore Gas & Electric Co.	Illinois Power Co.	Omaha Public Power District
Bonneville Power Administration	Kansas City Power & Light Co.	Public Service Co. of New Mexico
Central & South West Corp.	LADWP	Salt River Project
City Public Service, San Antonio	Long Island Power Authority	South Carolina Electric & Gas
Commonwealth Edison Co. (Unicom)	MidAmerican Energy Co.	Southern California Edison Co.
Consolidated Edison Co. of New York	Midwest Independent System Operator	Southern Company
DQE, Inc.	Nebraska Public Power District	Tennessee Valley Authority

DTE Energy	New England ISO	TXU Electric
		Wisconsin Electric Power Co.

While the Initiative is founded on a thorough analysis of the current challenges facing the industry, it is intended to be more than a retrospective review of events. Instead the Initiative is designed to provide solutions to today's emerging problems and to deliver these results rapidly. For the short term, the Initiative identifies and develops tools that minimize the risk of power outages and disturbances, enhancing reliability. In the long term the Initiative targets corrective actions and investments required to guide technology development for enhanced system reliability.

Electricity Technology Roadmap

In its scope and goals, the Power Delivery Reliability Initiative has served as a broad implementation project of several key concepts outlined in the Electricity Technology Roadmap Initiative—an ongoing EPRI-sponsored collaborative exploration of the opportunities and threats for electricity-based innovation over the next 25 years and beyond. In the power delivery area, a 1999 Summary and Synthesis report of the Roadmap (EPRI report CI-112677-VI) describes key technologies that could improve reliability through the early part of the 21st century and identifies funding gaps affecting their development and deployment.

Describing technologies for the power grid of the future, the Roadmap envisions that before 2010, the capability will exist "to achieve a unified, digitally controlled transmission grid to move large amounts of power precisely and reliably throughout North America, while managing an exponentially growing number of commercial transactions." A critical knowledge gap that the Roadmap identifies for ensuring the increased reliability and carrying capacity of the North American grid is "power flow control in complex grids, including software, hardware, communications systems, and integration with transaction management functions."

To achieve a continental electricity market, the power delivery module of the *Roadmap* notes the need for development of on-line system analysis technology. "On-line software tools will enable dispatchers to schedule wholesale power transfers on a continental scale, hour-by-hour. Such tools will be critical for enhancing reliability, promoting open access, transferring low-price electricity over long distances, and reducing operating costs by billions of dollars annually."

Transmission and Distribution Programs

The Power Delivery Reliability Initiative set out to bring this vision to reality by establishing two separate, but parallel, programs—one for transmission and another for distribution.

On the transmission side, the Initiative's Transmission Program adopted the following two-prong approach:

- A reliability/risk assessment

- Technology deployment to improve system performance.

The risk assessment aimed to comprehensively assess vulnerabilities of the North American power grid, for the first time, using newly developed probabilistic tools. The technology deployment component focuses on several near-term operating tools for enhancing the real-time reliability of the transmission grid in the summer of 2000.

The Initiative's Distribution Program also set out to analyze the current problems confronting the industry and to recommend ways to improve reliability. Distribution companies use a variety of distribution architectures, equipment, and operating practices. This diversity called for a different assessment approach than that used in the Transmission Program, relying on analysis of representative distribution systems using deterministic methods. Applying this case study approach to five representative systems, EPRI is integrating analysis results with industry surveys and data from other companies to create the first industry-wide "best practices" knowledge base for distribution systems. In parallel, EPRI is developing a self-audit template for each of the five distribution system types that will permit companies to evaluate their own system and practices.

Working with Initiative participants, EPRI established the following two-phase schedule for the Transmission and the Distribution Programs:

- Phase I spans project launch in late 1999 through April 2001.
- Phase II, which was defined in late 2000, will begin in April 2001 and be completed in 15-18 months.

PART I PHASE I OF THE POWER DELIVERY RELIABILITY INITIATIVE

3 PROOF OF CO NCEPT OF PROBABILISTIC RELIABILITY OR RISK ASSESSMENT (PRA)

Introduction

The first achievement of Phase I of the Initiative's Transmission Program is development of an improved method for assessing transmission system reliability. The technique—Probabilistic Reliability or Risk Assessment (PRA)—provides the capability for determining the probability or likelihood of an undesirable event on the transmission system and a measure of its severity. This capability provides a number of key benefits, including identification of the most critical potential generator or grid failures and determination of the most effective mitigation actions.

This section explains how PRA works, points out its advantages over traditional assessment methods, describes the software programs that enable the method, and reviews the deliverables provided to Initiative funders.

Reliability/risk assessment is a term describing evaluation of potential generator or grid failures for grid planning and operations. In grid *planning*, "reliability" is a measure that refers to the time-averaged condition of a system. In grid *operations*, "risk" is a measure that refers to the real-time instantaneous condition of a system. The Power Delivery Reliability Initiative applies reliability assessment in the study of the current North American grid in the planning sense. The Initiative seeks to identify potential critical contingencies, evaluate the probabilities of their adverse impacts, and recommend effective mitigation alternatives. In Phase II of the Initiative the concept of PRA will be extended to the real-time system operating arena to develop a Probabilistic Risk Monitoring system.

Traditional Assessment Methods

Traditional deterministic contingency criteria, used in conducting reliability/risk assessments on power systems, do not recognize the unequal probabilities of events that lead to potential operating security limit violations, nor the severity of such violations (see Figure 3-1).

Traditionally system security is assessed by simulating a set of contingencies without regard to the numerical probabilities of the contingencies. The relative likelihood of contingencies is considered loosely by recognizing that single outages (N-1) are more likely than double outages (N-2) and that generator outages are more likely than line or transformer outages. Therefore, to limit the contingency analysis to a reasonable number, typically single outages and some limited set of double or multiple outages are used.

Figure 3-1 Deterministic Critical Contingencies and the Field of Unreliable States

To model random outages in a rigorous probabilistic framework, some approaches have used Monte Carlo simulation. However, a very large number of samples are needed to compute a statistically significant reliability index for a large network. Applying Monte Carlo simulation, using an AC loadflow model, to a large interconnection with sufficient modeling details is computationally infeasible. Today power systems with more than 30,000 buses down to voltage levels of 100 kV must be modeled.

How EPRI's PRA Works

As an alternative, PRA methods, originally developed in the nuclear power industry, have proven effective in analyzing many kinds of reliability problems arising from the interaction of multiple factors in complex systems. EPRI's PRA methodology is a practical hybrid approach to reliability/risk assessment that allows users to incorporate the probability of an event within feasible data limitations.

PRA combines a probabilistic measure of the likelihood of undesirable events with a measure of the consequence of the events (that is, the impact) into a single reliability index. More strictly stated, the reliability index (RI) is defined to be the summation of the product of two quantities—probability and impact—summed over all simulated situations.

Thus,

$$RI = \sum p_i \cdot I_i$$

$$I \in \{Simulated\_Situations\}$$

Where, p_i is the situation probability

I_i describes impact of constant violations

In this definition and equation, "probability" is the probability of experiencing the impact (i.e., the probability of the initiating events—contingencies that could lead to violations of operating security limits—that cause the impact). "Impact" is measured by severity, which includes deviations from the following:

- Acceptable thermal loading of transmission lines and transformers
- Acceptable bus voltage levels
- Voltage stability
- Dynamic stability, in some systems.

In the most simplistic form, the impact may be measured by the distinct number of buses or lines that experience voltage violations or overloads.

In a more useful and accurate form, a voltage index, for example, can be defined as the summation of the product of the probability and the deviation of voltage below a certain level, summed over all outage situations and summed over all buses with violations. Similar reliability indices can be defined for thermal overloads, voltage stability, and dynamic stability.

EPRI's PRA methodology uses two software programs (see Figure 3-2). The Physical and Operational Margin (POM) program is a fast contingency simulation program that is used to simulate a large number of contingencies. This program seeks to identify voltage violations, thermal overloads, and voltage instability. The output from POM, together with probabilistic data, are entered into another software program—the Probabilistic Reliability Index (PRI) program. The PRI program produces a set of Reliability Indices of overload and voltage security for various zones of a wide-area system. The Reliability Indices, in turn, are input to a reliability database. This database is then analyzed to extract useful conclusions about the causes of potential failures and weak points in the system.

Figure 3-2 EPRI's PRA Methodology

During Phase I of the Initiative, two types of enhancements were made to the POM and the PRI program. One incorporated enhanced operating procedures in the POM. These procedures opened lines to avoid/relieve bottlenecks due to thermal overloads or voltage violations, and to simulate generation re-dispatch to reduce line overloads. The improvement to the PRI program applied a tree method to compute the rigorous probabilities of outage events and the severity of branch overloads and voltage violations.

PRA Results

A study using the PRA methodology described above produces the following four types of information:

1. **Assessment of Overall Reliability.** By weighting each contingency by its probability, the PRA approach determines a realistic average behavior computed for a random time in a planning period. This information is more useful than results of a deterministic assessment, in which each contingency is weighted equally despite differing probabilities of their occurrence.

2. **Assessment of the Margin of Reliable Operation**. The safety margin of the current system operating point can be measured by the additional amount of system load increase or power transfer before reliability constraints are violated. This safety margin can be calculated deterministically with POM results or probabilistically using the PRA methodology. The probabilistic concept is similar to the idea of "load-carrying capability" of a generation system with a given planning criterion (e.g., one day of load loss in ten years). In other words, if the current reliability index of the grid is better than the required minimum level, what additional amount of system load can the grid carry before the reliability index falls below the minimum acceptable level?

3. **Determination of Root Causes and Weak Points**. The PRA approach also helps to indicate root causes of grid problems and weak points on the system. For root causes, the PRA combines impact and contingency availability to reveal the most potentially damaging contingencies in the long run. For example, analysis may reveal a contingency that has small contributions to the Reliability Index but has the highest impact. For weak points, the voltage violation statistics may point out a given bus as "weak" if its violation expectancy—combining severity and probability—is high. This means that a weak bus must be one with both a severe violation and significant probability of occurrence.

4. **Evaluation of Effectiveness and Cost of Mitigation Plans**. The PRA methodology allows grid planners to quantitatively evaluate the effectiveness of mitigation efforts such as VAR compensation or generation support.

Example

Figure 3-3 illustrates the type of information a PRA study can provide. The figure shows results of the PRA study conducted on the Southern Control area of the Southeastern Electric Reliability

Council (SERC). This PRA application demonstrated how the method could be used to identify transmission bottlenecks and compute relative risk measures.

Figure 3-3 Sample Display Map Showing Voltage and Overload Risk

Figure 3-3 shows, on an annual basis, the four zones with the highest voltage risk and the four zones with the highest overload risk in the Southern Control Area. The zones are defined geographic areas in the Southern Company system. The circles indicate the four zones with the highest voltage risk, using the probability-weighted number of buses with voltage violations over the year. The diamonds indicate the four zones with the highest overload risk, using the probability-weighted number of overloaded branches for the four zones.

Value of PRA

The PRA methodology offers energy companies a more accurate tool than deterministic methods for assessing grid reliability under deregulated market conditions. Unlike traditional deterministic contingency criteria, PRA calculates a measure of the probability of undesirable events and a measure of the severity or impact of the events. The PRA provides the means to identify the most critical potential grid failures, evaluate their adverse impacts, and recommend effective mitigation alternatives.

PRA is useful in studies related to congestion management and "must run" unit decision making to improve system reliability. PRA also allows grid planners to assess the tradeoffs between the probability of a contingency occurring and the cost of operational changes to avoid those contingencies. This, in turn, can lead to the evolution of new business practices in the deregulated energy marketplace. For example, reliability can be quantitatively factored into new energy products. Conversely, new business practices affect system operations, and can be manifest in varying levels of reliability. As a result, PRA can be used to calculate the impact of new business practices on reliability.

In addition, PRA enables control room short-term planning. For example, it can assist planners in better coordination of outage scheduling of generators and transmission lines, and to determine the system reliability impact of doing maintenance outages. PRA also allows planners to conduct coordination studies on a wide-area basis.

Initiative efforts in Phase I proved the PRA to be a practical assessment method and fostered a greater awareness and acceptance of PRA among planners and operators. Work in Phase I also included significant preparatory work toward development of an on-line risk monitor, which will be completed in Phase II.

PRA Deliverables

The following three deliverables are available to funders in the Transmission Program of the Reliability Initiative:

- A license for the POM has been negotiated for use by the funders. As a result, funders will be able to conduct contingency analyses in their own regions.
- The PRI program is available for testing by the funders. With this program, funders can conduct probabilistic reliability studies of their regions.
- A user training workshop for the PRA methodology and the PRA software will be held in April 2001. This workshop will assist users in better understanding software operating procedures, data requirements, and interpretation of results. In addition, a user group will be organized to provide feedback on application issues and to guide future development of the program.

4 PROBABILISTI C RELIABILITY ASSESSEMENTS OF REGIONS OF THE NORTH AMERICAN GRID

Introduction

The PRA methodology offers energy companies a valuable practical tool for determining the probability of an undesirable event on a transmission system and a measure of its severity. Development of the proof-of-concept PRA took place in the Initiative through test applications of the methodology in four regions of the North American grid: the Southern Control Area of the Southeastern Electric Reliability Council (SERC), a portion of the American Electric Power (AEP) network, the Eastern Interconnection (EI), and the Electric Reliability Council of Texas (ERCOT) Interconnection. The successive studies of these four regions helped to refine the PRA methodology, demonstrate its capabilities, identify its limitations, and indicate improvements needed to increase the effectiveness of future assessments.

This section briefly summarizes each of these four studies, describing their objectives, methodology, results, and conclusions. The section also describes the revised plans to conduct a PRA study of the North American grid.

Southern Control Area of SERC

The first application of the PRA methodology to a sizeable control area was the PRA study of the Southern subregion of the SERC transmission grid. The method used in the study was based on past and ongoing EPRI PRA research. The study was conducted in the fall of 1999, and a final report was published in January 2000.

Objectives

The objectives of this study were to:

- Develop a practical PRA methodology and apply it to the sizeable Southern Control Area of SERC.
- Demonstrate this methodology for identifying transmission bottlenecks.
- Demonstrate how to compute Relative Risk Measures that could be used in subsequent studies of other control regions.

Methodology

The study tested all credible single and double contingencies of branch and generator outages and identified a list of critical contingencies. Southern Company Services provided the data necessary to calculate the probabilities of branch and generator outages, as well as six realistic scenarios of power transfers that stress the network. For each of these six scenarios, three seasonal peak conditions were established—summer peak, winter peak, and spring/fall peak.

Results

Two types of violations were observed—thermal overloads of branches (lines and transformers), and voltage level violations. The results identified transmission bottlenecks, and displayed and summarized this information in two ways. The first display method involved maps that show the location of bottlenecks by the geographical division of transmission zones and by seasonal peak (see Figure 4-1).

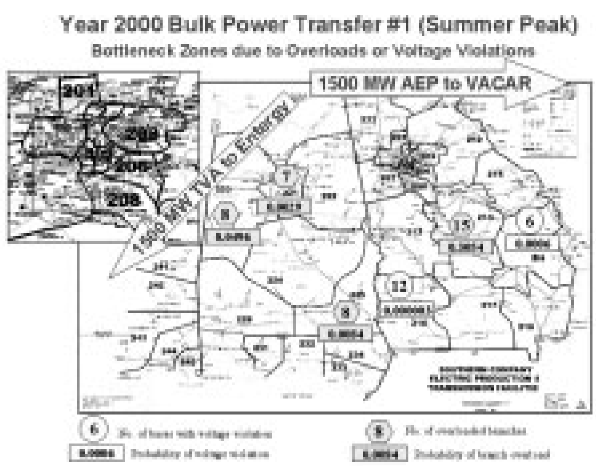

Figure 4-1 Sample Display Map Showing Bottleneck Zones

The four numbers in the circle and the hexagons indicate, respectively, the number of buses with voltage violations and overloaded branches. The two indices under the numbers indicate the probability of the contingencies that result in the violations. In other words, the top number indicates the severity of the risk, and the second number indicates the likelihood of encountering such an impact. The arrows show the directions and amounts of power transfers applied between neighboring regions in addition to base transfers from the Southern control area of SERC to or from these neighbors.

The second method of displaying results involved the use of bar charts to illustrate risk levels by transmission zone (see Figure 4-2).

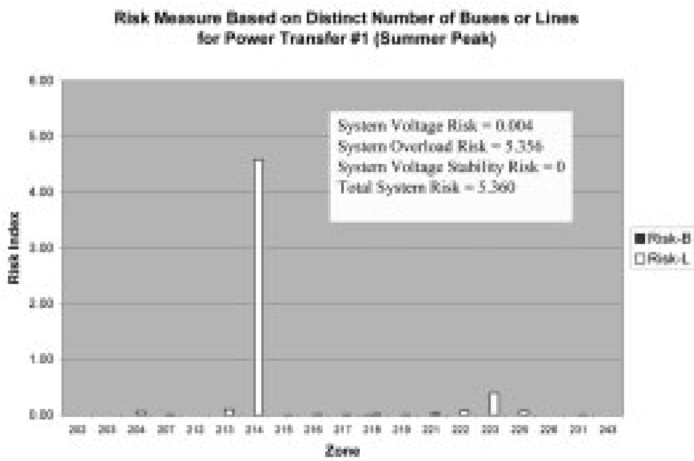

Figure 4-2 Sample Bar Chart Showing Risk Levels by Transmission Zone

Risk indices are shown for voltage and overload risks for each of the transmission zones in the 18 cases (i.e., six scenarios in three seasonal peaks). Zones with the highest values of risk indices represent bottlenecks in the system.

Conclusions and Value

The study demonstrated the ability of the methodology to identify transmission bottlenecks. The study team recommended that the PRA methodology be applied to additional regions of the North American grid. The study identified a number of methodology limitations to be addressed and incorporated in future applications of the methodology.

The study also illustrated the potential value of a real-time probabilistic risk monitoring system for monitoring the reliability levels of various bottleneck zones. (This system is to be developed in Phase II of the Initiative. See Section 7 of this report)

AEP Control Area

The second application of the PRA methodology, the Central Ohio Load Area of AEP, was studied in the spring of 2000, and a final report was published in August 2000.

Objectives

The objectives of this study were to:

- Refine the PRA methodology and address limitations identified in the Southern Company trial study and to improve the software for the enhanced methodology.
- Demonstrate use of this methodology to identify critical contingencies, represent probabilities of component failures, and identify effective countermeasures.
- Verify the practical feasibility of applying the methodology to future regional studies.

Methodology

The project team used the POM program to determine a list of critical contingencies for each scenario and identify the bottlenecks in the power system. Results include the load level at which critical contingencies (e.g., by exceeding stability, voltage, or thermal limits) are encountered, locations of violations, and their severity.

AEP provided three cases: a 2003 summer peak load base case, a peak load with extreme temperature, and a peak load with east-west power transfers. For each of the cases, three scenarios were simulated: a base case, base case with capacitors added and all voltages and branches monitored, and base case with capacitors added and only flowgates monitored. AEP provided a list of "N-1" and "N-2" contingencies involving branch and unit outages to be tested by the POM. (A number of the "N-1" contingencies involve multiple outages. "N-2" contingencies were formed from combinations of "N-1" contingencies.) For each of the base cases, the team determined the maximum load level before a critical contingency occurred and the number of critical contingencies occurring. A contingency was considered critical if it resulted in a constraint violation, defined to be a voltage drop below 0.92 per unit (p.u.), a thermal overload of 100% or higher of the thermal rating "Rate B" as defined in the PTI input format, or a voltage instability.

For the probability analysis, three cases were studied: an average summer peak base case, capacitor additions, and an additional 4000 MW power transfer. Critical contingencies were simulated for eleven lines, four transformers, and three generating units. The team conducted analyses to assess voltage stability, determine root causes and weak points, assess overload reliability, and evaluate the margin of reliable operation.

Results

Sample results of the contingency analysis illustrate PRA output. For the summer peak load base case, using the POM results only, the team found that the maximum load level before violations occur was 700 MW, if any of seven N-2 critical contingencies occurred. Violations were mostly voltage-level problems. With capacitors added, the maximum load level increased to 1200 MW if any of four contingencies occurred. For the extreme temperature case, the maximum load level was 400 MW, if any of 27 N-2 critical contingencies occurred. With VAR compensation, the load level rose to 1100 MW, if any of five contingencies occurred. For the base case with east-west power transfers, the maximum load level was 600 MW, if any of 20 N-2 critical contingencies occurred. With VAR compensation, the load level increased to 1200 MW if any of five contingencies occurred. While the safety margin is well defined by the load increases of 700, 1200, 400, 1100 and 600 MW, the probabilities of the defining contingencies and their number in these cases are not directly comparable. In other words, operating at these various safety margins does not give the same risk level. Using the probabilistic approach, even though the data were incomplete, the study illustrated the concept of defining the safety margin by plotting the reliability index against load increases and finding the intersection between the reliability index curve and a given reliability criterion level. (See Figure 4-3.)

Figure 4-3 Reliability Curve Plotted Against Load Increases

In the probability analysis, the team also found that the addition of capacitors in the Southern zone relieves all voltage violations. The case with the east-west power transfers does not dramatically affect the voltage reliability of the region. However, the case with extreme temperature <u>does</u> affect voltage reliability—the voltage reliability indices vary by a factor of 200 between the base case and the extreme temperature case. Voltage reliability mapping was displayed in figures (see Figure 4-4).

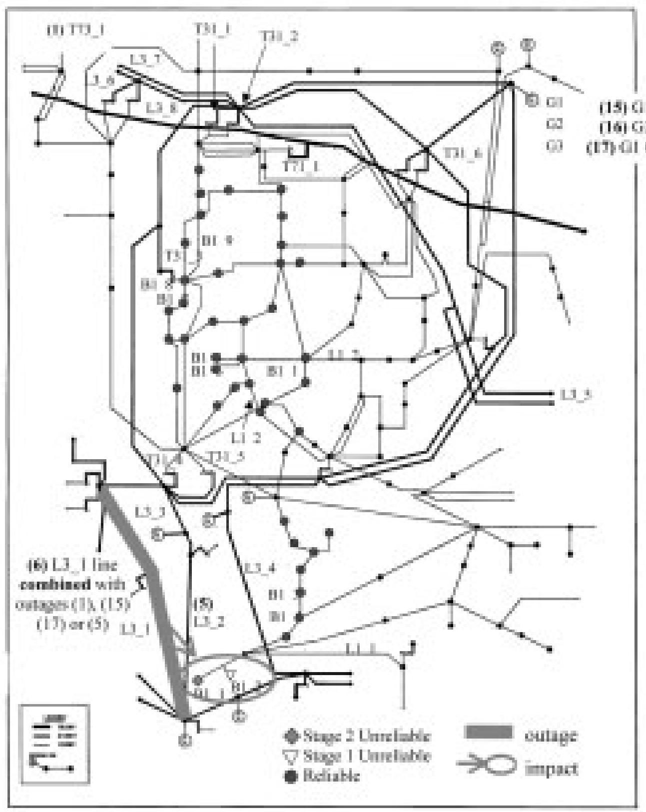

Figure 4-4 Sample Voltage Reliability

The concept of displaying geographically the reliability indices of buses or zones as load levels increase is demonstrated in Figure 4-5. As the load level increases, the reliability levels not only change but the problem area also spreads (compared to Figure 4-4, for example). This further illustrates the usefulness of real-time probabilistic reliability monitoring using a geographical display.

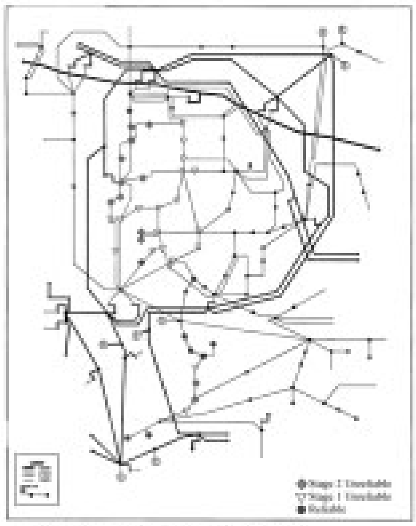

Figure 4-5 Load Level +1200MW

Another feature of PRA is its ability to perform root cause analysis. Figure 4-6 plots the impact of a contingency situation against the probability of that situation occurring, and displays the contribution of a given contingency situation to the total reliability index. For example, situation 6 + 1 contributes 57% to the total reliability index, has a high probability, but is a relatively low impact contingency. The iso-reliability curves conveniently separate the root causes (contingency situations) according to their effect on reliability. Planners will then be able to focus on mitigation measures against the major root causes.

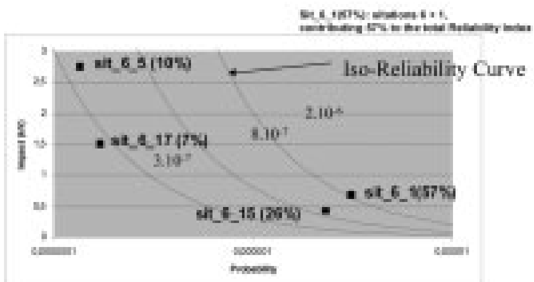

Figure 4-6 Contribution of a Contingency to the Total Reliability Index

Conclusions and Value

The contingency analysis shows that voltage problems exist in the AEP control area. In practice, sources of additional VAR compensation are added at the buses where voltage violations are identified to increase the margins. The study showed that Central Ohio voltages are more sensitive to load levels than power transfers. The study also showed that the area is more vulnerable to voltage violations than to overloads. Of the scenarios studied, the extreme temperature scenario is the most severe for both voltage sags and overloads.

The POM program analysis confirms AEP's understanding of the constraints in this area (i.e., limits of voltage level, voltage stability, and thermal level). The POM program further provided quantifiable results of these constraints that can be used in the probabilistic analysis to calculate reliability levels.

The PRA methodology was extended beyond what was accomplished in the Southern Company study to provide a framework for displaying the geographical spread of undesirable reliability impacts, linking causes and effects. The power of a real-time probabilistic risk monitor was illustrated through this exercise. Another advance was the concept of a probabilistic reliability margin, which was tested in the AEP study and showed promise for future applications. The use of a scatter plot of impact versus probability to identify major root causes was also demonstrated. This capability will greatly improve the effectiveness for grid planners and operators to improve system reliability.

Eastern Interconnection

The third application of the PRA methodology, the Eastern Interconnection (EI), was started in the fall of 2000, and initial results were presented at the Forward Planning Meeting in December. A final report is due in April 2001.

Objectives

The objectives of this study are to:

- Demonstrate use of this methodology to identify critical contingencies, represent probabilities of component failures, and identify effective countermeasures.
- Verify the practical feasibility of applying the methodology to future regional studies.

In addition, experience gained from the Southern and AEP studies are providing valuable insight in several areas, including the choice of situations to simulate, the need to handle probability rigorously, and the need to refine the Reliability Index definition.

Methodology

To establish areas for study, the project team developed a definition for zones in the EI, based on control area electrical distances, and defined 10 zones (see Figure 4-7). Eleven energy companies provided probabilistic outage data. Analysis of Tag Dump data for the EI during summer 2000 identified transfer flow patterns, occurrence of Transmission Loading Relief (TLRs), and bottlenecks. (The Tag Dump Program provides analysis of aggregated transaction schedules. See Section 5 of this report.)

Figure 4-7 Ten Zones of the Eastern Interconnection

The team then characterized an interconnection-wide summer 2000 base case, and performed a contingency simulation for this base case. Two NERC regions—the East Central Area Reliability

Coordination Agreement (ECAR) and SERC—provided contingency lists. The POM program automatically creates additional contingencies based on a specified unit size range and a minimum voltage level—N-1 contingencies totaled more than 1300, and N-2 contingencies totaled more than 33,000. This use of contingencies constituted a significant advance over previous PRA studies. Prior PRA studies used a single contingency list and one format for defining contingencies. The EI study uses multiple contingency lists and five different formats. This expansion of contingencies was undertaken to more completely cover potentially critical conditions.

Then, for each of five largest zones of the Eastern Interconnection, the Summer 2000 base case is being simulated for contingencies that are meaningful and comprehensive for each zone. Another five sets of cases are being simulated to determine the reliability of the five zones under higher levels of import into or export out of the zone. These cases are being analyzed using the PRA methodology to draw useful conclusions and observations.

Results

Preliminary results show that the Summer 2000 base case represented very high inter-control area flows, and many critical contingencies were encountered for the runs. Voltage instability was discovered for a number of contingency situations. The Eastern Interconnection study is emphasizing a thorough testing of the data, methodology, and the software so that the PRA software tools will be transferred to the funders for further regional PRA studies. The base case data for the Eastern Interconnection will be a useful starting point for these follow-on studies.

Conclusions and Value

This study is providing a thorough testing of the PRA methodology, data, and software. The data that are being compiled and analyzed offer a foundation for future studies. Also, the procedure developed in this study to define the ten zones will provide a valuable tool for dividing interconnections for the purposes of conducting future PRA studies.

ERCOT

The fourth application of the PRA methodology, ERCOT, is scheduled to begin in the spring of 2001, and data will be made available to funders for further PRA applications.

Licensing POM and PRI to Initiative Funders

At the September 28, 2000 Initiative meeting, the funders agreed that sufficiently accurate data were not available to move forward with a North American PRA study that would provide results at a confidence level required for widespread distribution. The Steering Committee felt more value could be obtained from further development of the PRA methodology. In addition, successes with the Southern and AEP PRA studies convinced Initiative funders that the PRA tools should be made available to them. In this way, each funder could conduct its own reliability studies. Funders also concluded that focus should be placed on NERC approval of the methodology and close cooperation with the NERC Reliability Assessment Subcommittee (RAS) during the conduct of regional PRA studies.

As a result, to provide direct and immediate value to the funders, a license for funders to use the POM Program has been negotiated, and the probabilistic reliability index will be delivered to funders for testing by April 2001. At the Forward Planning meeting in December 2000, funders agreed that the work conducted thus far to develop, benchmark, and validate the PRA tools in the Southern, AEP, and Eastern Interconnection studies has resulted in completion of approximately 80% of the steps toward a North American PRA study. The funders also agreed that individual companies will conduct the remaining PRA assessments.

5 NEAR-TERM O P ERATING TOOLS FOR ENHANCING THE SECURITY OF THE NORTH AMERICAN GRID

Introduction

In late fall 1999, the Power Delivery Reliability Initiative was launched in the aftermath of a series of highly publicized power outages that had occurred earlier that summer. The program plan for the Initiative noted the need for a balance of projects with long-term and short-term payoffs. At the latter end of the spectrum, a key objective of the Initiative was to "identify and provide tools that minimize the risk of power outages and disturbances to enhance short-term reliability."

At the Steering Committee meeting on January 27-28, 2000, experts in systems operations recommended that the Initiative develop a number of "no-regret" operational tools to help improve reliability in the near term—in time to help manage the grid during the summer 2000 peak loads.

As a result, at the February 23 meeting of the Initiative, a new effort was launched in parallel with the Initiative work already under way to conduct a workshop on summer 2000 operating strategies and develop two new operating tools—a Real-time Security Data Display (RSDD) and a Tag Dump program. The workshop was subsequently held on April 11, 2000, and the two tools were delivered on June 15, 2000.

Atlanta Workshop

The April workshop in Atlanta assembled nearly 50 funders of the Initiative to discuss transmission system operating issues for the upcoming summer. NERC and three trade associations joined EPRI in sponsoring the workshops, which included sessions with the following goals:

- Review problems from summer 1999 and predict problems likely to arise in the summer of 2000.
- Describe tools and procedures that were already planned at that time.
- Identify recommendations for operating procedures and coordination for summer 2000 operations.

The first session on past problems and potential future problems featured presentations by three security coordinators from the Eastern Interconnection, Western Systems Coordinating Council

(WSCC), and ERCOT. Problems occurring in 1999 included poor Available Transfer Capability (ATC) coordination, increasing numbers of transactions, growth outstripping transmission, VAR support not provided, unprecedented addition of new generation without needed transmission, and insufficient tools for Interconnection-wide analysis. For the future, the security coordinators foresaw ongoing Transmission Loading Relief (TLR) events that could threaten reliability. They predicted that another hot summer combined with large unit outages could result in the need to exercise interruptible loads.

The second session included a presentation on near-term tools already being rapidly developed as part of the Initiative to improve grid security in the summer of 2000. These tools included the RSDD and Tag Dump Program—a pair of web-based operating tools to aid security coordinators and control area operators in real-time monitoring and evaluation of system security (see descriptions below).

The third session of the morning and the afternoon session developed the following recommendations for improving operating procedures and coordination for summer 2000 operations:

- Recommend to security coordinators to sign up customers for voluntary load shedding.
- Remind security coordinators to complete all maintenance prior to the summer, and to use Security Data Exchange (SDX) and Interchange Distribution Calculator (IDC) data on outage schedules.
- Prepare formal reports on reliability at each security coordinator and control area.
- Recommend security coordinators to exchange day-ahead models and a procedure to carry out schedules.
- Appeal to all generators to complete maintenance before the summer and bring SDX schedules up-to-date.
- Use the tag dump data to provide net schedules for region-to-region and control area-to-control area flow projection.
- Train operators to maintain proficiency on new tools and policies.
- Monitor operating reserve and reactive reserve using the RSDD voltage display.

Value

The workshop provided a forum for reviewing problems from the summer of 1999, predicting problems likely to arise in the summer of 2000, describing tools and procedures already planned, and identifying recommendations for operating procedures and coordination for summer 2000 operations.

Real-Time Security Data Display (RSDD)

The RSDD is designed to provide security coordinators and control area operators with the first-ever interconnection-wide view of flowgate and voltage connections. As such, it offers a "bird's eye view" of grid reliability over a wide area (i.e., up to all of North America). The tool was developed in cooperation with NERC and initially implemented on the Eastern Interconnection.

The RSDD numerically and graphically displays real-time Interregional Security Network (ISN) data of voltages and flowgate flows. Accessible by security coordinators and control area operators via password access on either NERCnet or the Internet, the system allows up to 200 users to simultaneously access real-time information on 300 bus voltages and 50 flow gates (see Figure 5-1).

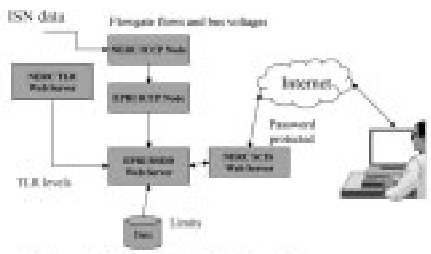

Figure 5-1 RSDD System Architecture

The system's Web server displays the data on bitmaps of NERC transmission grid maps—displaying customizable, color-coded flowgate flows and bus voltages (see Figure 5-2). For example, TLR level 3 and above is shown in red, and TLR 1 or 2 are shown in yellow.

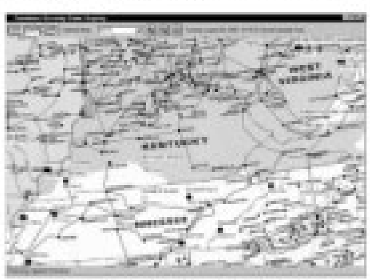

Figure 5-2 Sample RSDD Grid Map

The RSDD was demonstrated on-line to the NERC Security Coordinator Subcommittee (SCS) on June 14, 2000 in Kansas City. Two weeks later, the system was linked to the NERC Security

Coordinator Information System (SCIS) and made available on-line to security coordinators and control area operators. After feedback had been collected from users, additional enhancements were made.

Value

RSDD allows for better coordination between control area operators and improved interconnection-wide system reliability. Upon completion of the RSDD, Bob Cummings, NERC's Director of Transmission Services, noted, "RSDD currently enables security coordinators to see the wide area 'big picture' on common screens. This project has shown what we can accomplish when we put our heads together—RSDD is a widely available tool that is immediately useful."

Tag Dump Program

The Tag Dump Program is designed to analyze a "tag dump" of aggregated transaction schedules, on a control-area-to-control-area basis, or a security-coordinator-to-security-coordinator basis, from the IDC. The tag dump consists of information from the IDC that is aggregated into transaction schedules from sources to sinks. Hence, region-to-region or control-area-to-control-area net schedules and schedule projections are available—a source of data previously unavailable for the Eastern Interconnection. The Tag Dump Program automatically displays this information in bubble diagrams (see Figure 5-3).

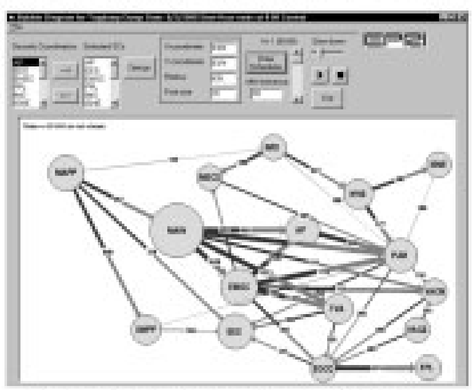

Figure 5-3 Sample Tag Dump Bubble Diagram

Starting in the summer of 2000, current IDC users, and others who had signed the NERC Confidentiality Agreement for Electric System Security Data (including security coordinators and control area operators), were able to access these data (via the NERC tag dump ftp site) and export the data to other applications to perform security analyses on their systems (see Figure 5-4). For example, the tag dump data can be used to perform operational planning studies (e.g., for the next hour), compute ATC for the next hour or next day, and develop scenarios of severe transfer patterns.

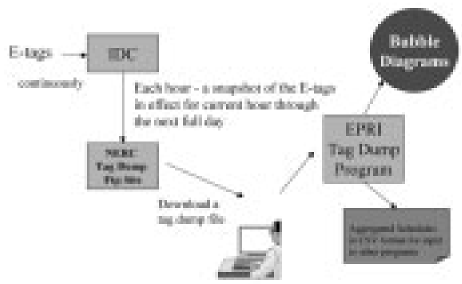

Figure 5-4 Tag Dump Input and Output

After its demonstration to the NERC SCS, the Tag Dump software was released on June 15, 2000 and made available to eligible users.

Value

The Tag Dump Program analyzes and displays information that improves power flow management on a control-area-to-control-area basis, reduces grid congestion, and helps avoid grid failures. Initiative funders quickly adopted the Tag Dump Program. "The Tag Dump was <u>very</u> well received by security coordinators," noted NERC's Lou Leffler. Warren Wu of TVA's Transmission Security & Services typified the responses. "Tennessee Valley Authority uses the EPRI Tag Dump program several times per day," he said. "TVA is able to apply this tool and predict transmission operational problems on TVA and the Eastern Interconnection. We appreciate the fast response on the Tag Dump program, and EPRI did a good job on it." EPRI has also used the program to analyze the historical flow patterns in the Eastern Interconnection from May 2000 to September 2000 and computed heavy flow indices. An effort to correlate the flow indices to TLRs and amounts of transactions cut has provided useful data to the NERC committees for policy evaluation.

6 CONVERGENC E OF EFFORTS

Introduction

An important achievement of the Reliability Initiative in Phase I has been the establishment and/or strengthening of cooperative working relationships between Initiative members and other industry entities. This cooperation has been fostered in the following three key areas:

- Linkage of efforts by EPRI and NERC to support projects related to improving the reliability of the North American transmission grid.
- Sharing of information between transmission grid and nuclear power plant entities.
- Connections between Initiative participants and representatives of grid market operations.

For Initiative members, this cooperation has provided a number of benefits—including the pooling of resources, the sharing of expertise, and a broadening of the Initiative's efforts to include objectives of mutual interest.

Coordination with NERC

EPRI has worked closely with NERC on the Reliability Initiative since the Initiative's earliest formulation in 1999. NERC representatives were instrumental in Initiative conceptualization and assisted in gathering support among industry leaders. In March 2000, the NERC Operating Committee unanimously endorsed the Reliability Initiative, and Committee members urged security coordinators to participate in the April 11 workshop to plan summer 2000 operating strategies. (The Operating Committee is responsible for developing operating policies and standards for the North American bulk electric system. Members include representatives of regional reliability organizations and energy companies.) EPRI also made a presentation to the NERC Planning Committee (previously known as the Adequacy Committee) and its Reliability Assessment Subcommittee (RAS), resulting in a resolution by the NERC PC to continue cooperation with EPRI in this area.

Value

The backing of this leading organization responsible for promoting electricity reliability in North America played a critical role in ensuring that the Initiative addresses the needs of a broad array of industry interests and provides useful tools to the security coordinators and control area operators who oversee transmission grid reliability, as well as transmission providers who need to plan for grid expansion.

In addition, the close working relationship between Initiative members and NERC has led to a pooling of resources to achieve benefits of mutual interest, while avoiding duplication of overlapping efforts. Noting this cooperation, Michael A. Agee of Duke Energy observed, "Closer working relations have developed between the various NERC Committees and EPRI that will provide positive value for the industry that funds both groups. The bridges built during this process should enable additional opportunities to develop much needed tools to ensure grid reliability."

Evidence of this pooling of resources can be seen in the work plan for Phase II of the Reliability Initiative. The chief NERC projects planned for 2001 include the following:

- Central Repository
- E-Tag Version 1.7
- Common Power System Model (CPSM)/Common Information Model (CIM)
- Flow Impact Study Tool (FIST)
- Electronic Scheduling/OASIS Phase II.

In Phase II of the Reliability Initiative, one of the tasks ("Tools and Data to Improve Interregional Coordination") involves support for several of these NERC activities related to the Initiative. The task will provide grid operators with Tag Dump analysis of historical data, information to assist NERC in proposing standards for use of the PRA, support for data infrastructure for CIM, and support for FIST. (See Section 10 of this report for more information.)

Cooperation Between Transmission Grid and Nuclear Entities

The nuclear industry has had long experience with risk-based assessment methods and risk monitors. For example, the Risk- and Reliability-Based Methods Target within EPRI's Nuclear Division focuses on development of probabilistic safety assessment applications. Researchers in the Nuclear Division provided consultation on the nuclear industry's probabilistic assessment methods and the probabilistic risk monitor planned for development in Phase II.

In addition, a key approach to improving transmission grid reliability involves the grid interface with nuclear plants. Through the Initiative, efforts were made to share knowledge and expertise with representatives from the nuclear industry in order to address improvements to this interface. As part of the Initiative, presentations were made to the Nuclear Regulatory Commission to describe the Initiative's goals and progress. Consultation was also received from EPRI's nuclear experts. A concrete result of this cooperation is the plan in Phase II of the Initiative to develop a two-way data link for real-time exchange of reliability indices between grid and nuclear plant operators. (See Section 11 of this report for more information.)

Value

Expert consultation and discussion with representatives of the nuclear industry applies nuclear power's long experience with risk assessment methods and monitors to the design of the Initiative's tools and improves the interface between grid and nuclear risk monitors.

Cooperation Between Grid Operations and Grid Market Entities

In recent years, many observers of the North American transmission grid have recognized the inseparability of market and reliability issues, and have noted the need for market-oriented solutions to reliability. The Reliability Initiative plan pledged that efforts would seek solutions to maintain system operation <u>and</u> efficient market operation. The preliminary assessment report published at the start of the Initiative recommended that "in addition to the technical reliability issues, related market issues should also be considered."

Through the Initiative, connections were made with representatives of grid market operations. For example, EPRI representatives presented information on behalf of the Initiative to the NERC Market Interface Committee (MIC) and the Western MIC. (The MIC was formed in May 1999 to assess the impacts of NERC's reliability standards, practices, and tools on the commercial electricity markets in North America.) At the MIC's August 24, 2000 meeting, committee members formally endorsed the Initiative. The MIC also reviewed the status of the Initiative and encouraged consideration of how such systems can be used to support the information needs of market participants. Specifically the MIC recommended that NERC offer the RSDD to all entities (including Power Supply Entities) that are registered with the OASIS/E-tag registration site.

Value

Coordination between system and market operation entities helps ensure that Initiative efforts address the need to maintain secure system operation <u>and</u> enable efficient market operation.

Part II Phase II of the Power Delivery Reliability Initiative

7 ON-LINE CONT INGENCY AND RISK ANALYSIS/MONITORING

Introduction

For Phase II of the Reliability Initiative, one of the highest-priority projects is the development of two operational tools for on-line contingency analysis and risk monitoring. This project will extend to the operational arena two planning tools that were developed and successfully demonstrated in Phase I. The tools are the POM Program, which enables analysis of critical contingencies, and the PRI Program, which provides risk indices of voltage and overload security on a system. Together, these tools will enable grid operators to improve the operational reliability of the transmission grid by conducting real-time accurate assessments of voltage violations and thermal overloads.

Physical and Operational Margin (POM) Program

This project will implement on-line the POM Program—a software program for fast simulation of a large number of critical contingencies to identify voltage violations, thermal overloads, and voltage instabilities. The POM Program was benchmarked and validated as a planning tool in Phase I through three successive PRA studies on the Southern, AEP, and Eastern Interconnection systems. In addition, improvements were made to the POM Program during Phase I to simulate generation re-dispatch to reduce line overloads and compute the probability of joint overload events.

Development of an on-line POM Program involves enabling the software to input and analyze data that reflect real-time system conditions. For example, data on current conditions could be input hourly, enabling grid operators to evaluate critical contingencies based on data from the last hour.

This project will adapt the existing POM to run in an on-line environment; approximately 40% of the work necessary for this adaptation was completed in Phase I. A future version of the on-line POM could integrate a power flow management database system and CIM, enhancing capabilities for real-time data exchange across platforms.

The Phase II deliverable will be a beta version of the POM Program.

Value

An on-line POM program would enable grid operators to simulate real-time critical contingencies, and to identify effective mitigation measures to reduce the frequency and severity of outages and other grid failures.

Probabilistic Risk Monitor

The Probabilistic Risk Monitor (PRM) will combine on-line versions of the POM Program and the Probabilistic Risk Index (PRI) to provide real-time probabilistic risk indices. Indicating the probability and severity of undesirable impacts, these indices can be used to assess changes in reliability over time and evaluate various mitigation methods. Like the POM Program, the PRI program was demonstrated and improved during Phase I in regional PRA studies.

The Phase II PRM will extend the Phase I PRI using forced outage rates to represent failures. (A possible future enhancement of the on-line PRM would use frequency and duration or failure repair phenomena to model the risk. Development of this monitor would require additional data collection and proof-of-concept.)

The Phase II deliverable will be a beta version of the PRM software.

Value

An on-line PRM will allow operators to understand the tradeoffs involved in operating their transmission system under a variety of conditions and how best to respond when system overloads or voltage violations occur.

8 PRA ENHANCE M ENTS AND IMPLEMENTATION

Introduction

A second Phase II project involves several efforts to improve the PRA methodology as a planning tool. Chief among these efforts is an upgrading of the underlying methodology to enhance accuracy, flexibility, and additional analysis capabilities. Guidelines will be developed for PRA standards, which will foster more uniformity in PRA analysis. In addition, a user group will be established to assist in applications and propagate use of the methodology. Together, these projects will enable grid planners to increase grid security through improved analytical accuracy and consistency.

PRA Enhancements

As a planning tool, EPRI's PRA is an analytical method of determining the likelihood of an undesirable event on the transmission system and a measure of its severity. In Phase I, a beta version of PRA was demonstrated and improved in three regional studies. These studies showed PRA to be a practical and feasible method of studying congestion management and aiding decision making to improve system reliability.

In Phase II, proposed new PRA features include the following:

- **Sensitivity Analysis of Outage Data**—analysis to determine the optimum quality of input data needed to produce useful PRA results (e.g., region-specific versus generic data).
- **Operating Procedures**—model refinement to incorporate operating procedures in the analysis.
- **Must-Run Units**—use of the methodology to identify must-run units.
- **Dynamic Stability**—more robust capabilities to model dynamic phenomena.
- **Reliability Indices**—capabilities for determining what indices are meaningful, and the value of absolute versus relative indices.
- **Post-Processing of Data**—improved ability to distill information, facilitating interpretation of results.

The Phase II deliverable will be PRA Program Version 2.0.

Value

Improvements to the PRA will increase the program's accuracy and applicability, and provide additional information to planners.

PRA Guidelines

PRA guidelines will include standards for PRA data requirements and analysis performance. A numerical index for a reference level of reliability will also be developed. Rather than a standard number for all systems, this index will offer an indication of the level of reliability that a particular system is aiming to maintain. The Phase II deliverable will be a guidelines report.

Value

PRA guidelines will help establish uniformity in PRA data and the application of the methodology.

PRA User Group

A user group will be formed to support further development and application of the PRA methodology. The group will offer a forum for Initiative members and their staff to discuss new features and implementation experience. Ongoing throughout Phase II, the user group will meet on dates to be determined.

Value

Through the PRA User Group, members will have an opportunity to share lessons learned, compare problem-solving approaches, and receive information on product refinement.

9 ENHANCEMEN T S OF RSDD AND TAG DUMP

Introduction

During Phase II, the two short-term operational tools developed in Phase I—RSDD and Tag Dump—will be upgraded to incorporate enhancements that users have suggested. The enhancements will expand the type and volume of data available for analysis, accelerate analysis, clarify the display of information, integrate the software with other applications, and allow more customization of features. These improved tools will help security coordinators relieve grid congestion and avoid failures.

Real-Time Security Data Display

RSDD is a software program that provides security coordinators and control area operators with an interconnection-wide view of flowgate and voltage connections. The program numerically and graphically displays real-time ISN data, allowing access to up to 300 bus voltages and 50 flowgates. With these capabilities, RSDD provides an ideal tool for checking the accuracy of area forecasts. Since RSDD introduction in June 2000, security coordinators and control area operators in several NERC regions have adopted the program for daily use.

Phase II enhancements to RSDD will include display of additional data, (e.g., reactive reserves and PRM indices), improved graphics, and a more operator-friendly interface.

The Phase II deliverable will be Version 2.0 of RSDD.

Value

The additional data made available in Version 2.0 will provide operators a more accurate indication of current conditions, enabling improved decision making. Combined with an enhanced graphical display and user interface, the data will also offer operators better "drill-down" capabilities on single data points (e.g., the ability to click on a data point, pull up a tablet display of data, and receive a historical trend of that data point).

By providing security coordinators a more complete picture of wide-area activities, these software upgrades will permit them to take the necessary steps to ensure the operational reliability of the transmission grid.

Tag Dump

The Tag Dump Program is designed to analyze a "tag dump" of aggregated transaction schedules, on a control-area-to-control-area basis, or a security-coordinator-to-security-coordinator basis, from the IDC. Since first introduction of the Tag Dump in June 2000, several entities—including the Tennessee Valley Authority and the Mid-America Interconnected Network—have regularly used the program to help plan the current day's operation and calculate ATC.

In Phase II, the Tag Dump program will be enhanced to interface with electronic schedules, display more flexibly-defined bubble diagrams, and integrate more effectively with other applications (e.g., POM and RSDD). The program will also be improved to automate analysis of scheduling data, enable Tag Dump on an interconnection level and posting to the web, and allow coordination of tag schedules with flow-based schedules.

The Phase II deliverable will be Version 2.0 of the Tag Dump program.

Value

With the new features, the Tag Dump program will become a more useful, powerful tool for scheduling wholesale transactions and security analysis.

10 TOOLS AND D ATA TO IMPROVE INTERREGIONAL COORDINATION

Introduction

As Regional Transmission Organizations (RTOs) throughout North America establish themselves, submit their filings with the Federal Energy Regulatory Commission (FERC), and begin operation, they face the challenge of meeting the requirements of FERC Order 2000. According to this order, one of the eight minimum functions that an RTO must satisfy is "interregional coordination." This function involves a host of "seams issues"—issues related to operations at regional boundaries that affect data sharing, model interfaces, and regional procedures with the potential to impact adjoining regions.

The challenge was articulated during an EPRI-sponsored workshop in October 2000, which brought together representatives of the major RTOs and ISOs in North America. At that workshop, participants listed the need for tools to cost effectively address seams issues as one of the leading priorities.

To meet this need, Phase II of the Initiative proposes a number of projects aimed at improving interregional coordination, including the following:

- Data analysis of interregional transactions using Tag Dump
- Support of planning and operations standards for PRA use
- Assistance in development of a CIM database for interregional coordination
- Support of NERC activities related to the Initiative.

Tag Dump Analysis

Data analysis on an interregional basis using the newly developed Tag Dump tool could offer important insights into interregional transaction patterns and bottlenecks. This Phase II project will use the program to analyze historical tag dumps and occurrences of TLR.

The Phase II deliverable will be a report documenting data analysis.

Value

With the results of this analysis, RTOs will be better able to conduct day-ahead marketing, plan generation scheduling, and operate market-response programs.

Planning and Operations Standards

EPRI will provide information to NERC for use in proposing standards for planning and operation (e.g., in the use of PRA). For planning, these standards will help establish a consistency in use of the PRA and in collection of data on transmission analysis. For operation, the standards will help develop uniform reliability indices and guidelines for system operation.

Support for CIM Data Infrastructure

This project will support work to begin development of a CIM database for interregional coordination. At present, PRA studies are conducted with available data—including information on line outage status and gross approximations of generation and load profiles. Ultimately, a CIM database could be compiled from the control centers of various regions to produce a database for the Eastern Interconnection. While this is a long-term goal that first requires completion of the CIM database, preparatory work will be undertaken in this project to begin development of a CIM infrastructure.

The deliverable is ongoing collaboration and mutual support on the development of the industry's IT infrastructure for ensuring reliability, and market efficiency.

Value

CIM compliance will offer RTO control center managers the flexibility to combine, on one or more integrated platforms, software that best meets their needs for system economy and reliability. By providing common information, the CIM minimizes data duplication, reduces data entry errors, and organizes critical data in a useful framework. The rich information content the CIM accommodates offers many opportunities for data mining to aid applications in grid operation, grid planning, market operations, and other enterprise functions.

NERC Activities

NERC is undertaking or planning to undertake a variety of activities to promote interregional coordination. Funds permitting, this project will support those activities related to the Initiative, including the following:

- **Real-Time Topology Through the ISN**—This tool will automatically determine the accuracy of the network topology in real time using the ISN. This capability will support the IDC, which will provide congestion management tools, including transaction impact analysis and TLR.

- **Power Flow Data Base System**—This database will provide common data on multi-regional power flows to aid in interregional congestion management.
- **Master ID Naming Standard**—This central repository or database of names will establish uniformity in the names of buses and generators in the NERC Multi-regional Modeling Working Group database, other NERC databases, and a company's own database.
- **Flow-Based Study Tool (FIST)**—FIST is designed to analyze flow impacts of reservations and energy transaction schedules to reduce overbooking of transmission, reduce dependence on TLR, and accommodate existing and alternative reservation and scheduling business models.

The deliverables will be a real-time topology, a power flow database, a standard for renaming, and the FIST software.

Value

Together, these efforts will help solve critical seams issues between regions, contributing to the improvement of real-time reliability of the North American grid.

11 IMPROVED INT E RFACE WITH PLANT OPERATORS

Introduction

As grid planners and operators deploy new risk assessment tools, assessment results involving voltage buses near a nuclear plant could be made automatically available to plant operators. Such results could indicate the probability of unsatisfactory voltage levels at nearby buses and allow plant operators to adjust risk calculations and implement necessary precautions. Similarly, information from nuclear risk meters that indicate potential future plant outages could help grid operators conduct their own risk calculations and develop alternative plans.

This Phase II project will develop tools to support the two-way exchange of real-time information on grid reliability and plant availability. Such an exchange will improve the operational reliability of the transmission grid and ensure the safe operation of nuclear plants.

Two-Way Data Link

The development of a two-way data link between the transmission grid and nuclear plants involves additional work on two products—the RSDD and the on-line risk monitor.

An RSDD interface will be developed to exchange real-time information on grid reliability indices and plant availabilities. The interface will indicate which data points in the existing RSDD—actual voltages and power flows—are provided to the plants.

The on-line risk monitor to be developed in Phase II will display the risk levels of voltage buses near nuclear power plants, and the plants will have access to these displays. This project will also develop the means by which these risk levels are sent directly to the plants' own risk meters. In addition, for grid operators, this project will develop the means by which indices can be directly received from nuclear risk meters—indicating when a nuclear plant is "going to red" prior to an outage.

Specifications for a data exchange between the on-line risk monitor and the nuclear plant risk meter will be developed in a technology review report. The data exchange will be demonstrated in Phase II.

Value

The two-way data link will give plants an earlier warning of deteriorating voltage levels at nearby buses, providing them additional time to activate backup equipment and implement other actions. For grid operators, it will allow the operators to conduct revised risk calculations on the grid to reflect a higher forced outage rate for that plant.

Part III Charting a Course for Improving Grid Reliability

12 RECOMMENDA TIONS FOR IMPROVING GRID RELIABILITY

Introduction

EPRI supports broad-based efforts throughout the electric power industry to improve the operation and planning of the North American power grid. The Electricity Technology Roadmap has given direction and structure to these efforts. One portion of this EPRI-sponsored collaborative program has established goals and research programs designed to ensure the increased reliability and carrying capacity of the North American power grid.

In the past year and a half, to achieve the goals articulated in the Roadmap, representatives from throughout the power industry have proposed recommendations for future work in grid operations and planning. These recommendations originated from across the full spectrum of industry interests. They were proposed in meetings that assembled a wide cross-section of industry representatives from energy companies, RTOs/ISOs, government agencies, research institutes, and trade organizations. Meetings included the following EPRI-sponsored workshops:

- EPRI-led focus groups held in Atlanta on June 7, 1999 and in San Diego on February 7, 2000
- The Summer 2000 Operating Strategies Workshop held in Atlanta on April 11, 2000
- An RTO/ISO Workshop held in Holyoke, Massachusetts on October 23, 2000
- The Forward Planning Meeting of the Power Delivery Initiative held in New Orleans on December 5–6, 2000
- Meetings of the Steering Committee of the Power Delivery Initiative.

In addition, a number of these recommendations have been outlined in several reports, including *Issues and Solutions: North American Grid Operations and Planning (2000-2005), Probabilistic Risk Assessment for the Southern Control Area in SERC,* and *Application of Probabilistic Reliability Assessment to a Part of the AEP System.*

This section lists and discusses 23 of the recommendations relevant to grid reliability that have been proposed in recent months. The goals and recommendations are presented here for consideration by industry organizations and to help set an agenda for future endeavors aimed at improving the North American power grid.

Goals to Improve the Reliability and Efficiency of the Grid

The goals of the Electricity Technology Roadmap relevant to grid reliability and efficiency include the following:

- **Enhance grid reliability.** Develop planning and on-line operational tools to identify bottlenecks in the system and reduce the risk of major outages.
- **Increase carrying capacity.** Support development of tools such as electronic Flexible AC Transmission System (FACTS) controllers that allow existing transmission lines to be loaded closer to inherent thermal limits, effectively increasing their capacity, and reducing geographic constraints on transmission power and services.
- **Improve market efficiency.** Develop tools and methods that promote open access, reduce grid congestion, reduce operating costs, enable commercial transactions, and enable wholesale transactions to be conducted on a continental scale.
- **Guarantee the integrity and availability of the information network.** Research, develop, and apply secure and adaptive information systems, network technologies, and management tools for improved planning and on-line analysis.
- **Enhance interregional coordination.** Provide tools for regional management that support data sharing and model interface at regional boundaries, and support the safety and availability of the nation's grid.
- **Balance public and private interests.** Provide tools and information to ensure that public policy, roles, and responsibilities guarantee the public good while permitting free market forces to serve private interests.

Recommendations

The recommendations cover an array of issues. They seek to improve grid reliability and market efficiency by improving existing planning and operations tools, as well as developing advanced new tools. The recommendations address the wider area interconnection or "seams" issues, aiming to improve transactions and information exchange between regions. They also suggest methods and tools for data standardization to enhance the efficiency and security of the information network. In addition, a number of recommendations extend beyond energy company efforts to regulatory and institutional efforts that could improve market operations.

Table 12-1 lists the recommendations in eight categories and indicates how these recommendations address the goals of the Electricity Technology Roadmap. Following the table is a discussion of the recommendations.

Table 12-1 Recommendations for Improving the Reliability and Efficiency of the North American Power Grid

	Goals of Electricity Technology Roadmap Relevant to Grid Reliability and Efficiency					
Recommendation	**Enhance Grid Reliability**	**Increase Carrying Capacity**	**Improve Market Efficiency**	**Guarantee Integrity and Availability of Information Network**	**Enhance Inter-regional Coordination**	**Balance Public and Private Interests**
PRA						
Enhance PRA to improve outage data, include dynamic stability, and promote industry standards.	X	X	X			X
Address PRA limitations to improve rigor of calculations, include re-dispatch, etc.	X	X	X			X
Apply PRA to entire North American grid.	X	X	X		X	X
Develop wide-area probabilistic risk assessment.	X	X	X		X	X
Security Tools						
Develop on-line real-time risk monitor.	X		X	X	X	X
Develop tools for studying recent grid conditions.	X	X				X
Develop topology estimator.	X	X	X	X	X	X
Develop concept of virtual ISO using CIM.	X	X	X		X	X
Integrate heat wave forecasting into grid reliability applications.	X	X	X		X	X
Implement flow-based congestion management.	X	X	X		X	X
Develop wide-area ATC/TTC coordination.	X	X	X		X	X
Establish system for tariff on transmission use.			X		X	X

	Goals of Electricity Technology Roadmap Relevant to Grid Reliability and Efficiency					
Recommendation	**Enhance Grid Reliability**	**Increase Carrying Capacity**	**Improve Market Efficiency**	**Guarantee Integrity and Availability of Information Network**	**Enhance Inter-regional Coordination**	**Balance Public and Private Interests**
Develop system of Emergency Management and Restoration.	X			X	X	X
Planning Tools						
Integrate EPRI planning tools into new RTOs.	X	X	X		X	X
Apply PRA techniques to gain understanding of the measures used.	X	X	X		X	X
Apply real-time operating data and applications in the planning environment.	X	X	X		X	X
Develop and apply new tools that use probabilistic approaches.	X	X	X		X	X
Develop planning tools that accommodate variety of emerging technologies, including distributed resources and FACTS devices.	X	X	X		X	X
Seams Issues						
Develop Flow-based Impact Study Tool (FIST).	X	X	X		X	X
Establish standards for real-time grid modeling and data exchange.	X		X		X	X
Investigate methods of doing internal congestion management without adversely impacting other RTOs.	X	X	X		X	X
Data Standardization and Exchange						

	Goals of Electricity Technology Roadmap Relevant to Grid Reliability and Efficiency					
Recommendation	**Enhance Grid Reliability**	**Increase Carrying Capacity**	**Improve Market Efficiency**	**Guarantee Integrity and Availability of Information Network**	**Enhance Inter-regional Coordination**	**Balance Public and Private Interests**
Implement CIM.	X		X		X	X
Expand use of CIM for data exchange and integration.	X		X		X	X
Implement wide-area monitoring through CIM.	X	X	X		X	X
Countering Threats						
Investigate wider implementation of "safety nets."				X	X	X
Work with federal agencies on critical infrastructure protection project.				X	X	X
Regulatory/Institutional						
Develop market-based mechanisms that provide accurate price signals.	X	X	X		X	X
Establish institutional/regulatory processes in which transmission availability drives generation siting.	X	X	X		X	X
Develop tool that enables region-wide estimation of costs of transmission additions.	X	X	X		X	X
Human Resources						
Develop better human-machine interface for operators.	X		X			X
Develop tools to enhance planner & operator productivity.	X	X	X			X

	Goals of Electricity Technology Roadmap Relevant to Grid Reliability and Efficiency					
Recommendation	Enhance Grid Reliability	Increase Carrying Capacity	Improve Market Efficiency	Guarantee Integrity and Availability of Information Network	Enhance Inter-regional Coordination	Balance Public and Private Interests
Develop web-based methods to enhance operator and planner training.	X	X	X			X
Identify ways to attract more students to the power industry profession.						X
Develop ways of educating stakeholders on operation and planning methods and criteria.	X	X	X		X	X

PRA

The PRA methodology, developed in Phase I of the Power Delivery Reliability Initiative, offers energy companies a more accurate tool for assessing grid reliability under deregulated market conditions. Unlike traditional deterministic contingency criteria, PRA calculates a measure of the probability of undesirable events and a measure of the severity or impact of the events.

Recommendations have been proposed to improve the current version of the methodology to include capabilities for modeling dynamic phenomena, determining the optimum quality of input data, and incorporating operating procedures. These improvements are proposed tasks in Phase II of the Reliability Initiative. Other recommendations address limitations of the PRA methodology, complete its application to the entire North American grid, and develop a wide-area PRA.

Security Tools

Recommendations for new security tools include a variety of suggestions to increase the real-time, on-line capabilities of system operators for improving grid reliability, increasing grid capacity, increasing grid controllability with FACTS devices or phase shifters, and improving market efficiency. In Phase I of the Reliability Initiative, work began on development of an on-line probabilistic risk monitor, and the completion of this work is proposed for Phase II. A topology estimator would automatically determine the accurate topology in real time to support on-line security applications.

A virtual RTO is a tool that would utilize a number of new technologies, including the CIM, to perform the functions of an RTO without actually forming an RTO. This tool enables users to more easily address inter-RTO seams issues, and integrate systems under varying degrees of deregulation and restructuring. A flow-based congestion management tool has been proposed as part of the NERC Flow-based Impact Study Tool (FIST). FIST will reduce overbooking of transmission and reduce dependence on TLR through analysis of flow impacts of reservations and energy transactions schedules. Another recommendation was a tariff on transmission use, which would allow a toll collection system to be established based on an equitable measure derived from dc loadflow.

Planning Tools

The recommendations for new planning tools acknowledge the changing nature of the planning environment. Grid planning tools as a whole must take advantage of the availability of real-time data, advances in grid operation tools, and advances in transmission technologies, such as FACTS devices, which increase the controllability and effective capacity of the grid. Planning tools must also be extended, and in some cases reinvented, to meet the performance and functionality needs of the new business environment (e.g., via probabilistic risk assessment techniques). Given the dynamic and rapidly changing nature of industry restructuring, recommendations also seek planning tools that are highly flexible and capable of accommodating a variety of emerging technologies.

Seams Issues

A number of recommendations have been proposed to address "seams issues"—issues related to operations at regional boundaries that affect data sharing, model interfaces, and regional procedures with the potential to impact adjoining regions. For example, FIST would enable an RTO to manage reservations and scheduling that would cause congestion in other RTOs.

Data Standardization and Exchange

As the need increases for sharing data within an organization and between regions, the need for data standardization is increasingly recognized. Recommendations in this area focus on implementation and expansion of the CIM. CIM compliance will offer RTO control center managers the flexibility to combine, on one or more integrated platforms, software that best meets their needs for system economy and reliability. By providing common information, the CIM minimizes data duplication, reduces data entry errors, and organizes critical data in a useful framework. The rich information content that the CIM accommodates offers many opportunities for data mining to aid applications in grid operation, grid planning, market operations, and other enterprise functions.

Countering Threats

A recent White House report indicated that the power grid is one of the two national infrastructures that are most vulnerable to the threat of terrorism. Investigating a wider implementation of "safety nets" and continuing work with federal agencies on the critical infrastructure protection project will help counter potential threats to energy control centers and systems.

Regulatory/Institutional

A number of recommendations look beyond the possible future efforts of the business sector to possible regulatory actions designed to improve the efficiency of the power market. These recommendations address issues involving pricing, a new planning sequence for generation and transmission, and region-wide estimation of the costs of transmission additions.

Human Resources

In the area of human resources, the power industry in general, and power system planning and operation in particular, share a crisis of human resources. Competition is forcing a hard look at staff size, often leading to downsizing. As a result, energy company personnel are often asked to complete more tasks with fewer people. This trend is fueling the need to provide tools to enhance productivity and training.

A ACRONYMS

ACE	Area Control Error
AEP	American Electric Power Company
API	Application Program Interface
ATC/TTC	Available Transfer Capacity/Total Transfer Capacity
CA	Control Area
CIM	Common Information Model
CPSM	Common Power System Model
DOE	Department of Energy
ECAR	East Central Area Reliability Coordination Agreement
EEI	Edison Electric Institute
EI	Eastern Interconnection
ERCOT	Electric Reliability Council of Texas
E-tag System	Electronic Tagging System
FACTS	Flexible AC Transmission System
FERC	Federal Energy Regulatory Commission
FIST	Flowgate Impact Study Tool
IDC	Interchange Distribution Calculator
IEEE	Institute of Electrical and Electronics Engineers
IPP	Independent Power Producer

ISN	Interregional Security Network
ISO	Independent System Operator
MIC	(NERC) Market Interface Committee
NERC	North American Electric Reliability Council
NERCNet	NERC's communication network supporting ISN and IDC
NRC	Nuclear Regulatory Commission
OASIS	Open Access Same-Time Information System
POM	Physical and Operational Margin program
POST	Power Outage Study Team
PRA	Probabilistic Reliability or Risk Assessment
PRI	Probabilistic Reliability Index
PRM	Probabilistic Risk Monitor
PSE	Purchase or Sale Entity
PTI	Power Technology Incorporated
p.u.	Per Unit
RAS	(NERC) Reliability Assessment Subcommittee
RI	Reliability Index
RSDD	Real-time Security Data Display
RTO	Regional Transmission Organization
SC	Security Coordinator
SCIS	(NERC) Security Coordinator Information System
SDX	Security Data Exchange
SERC	Southeastern Electric Reliability Council

TLR	Transmission Loading Relief
TMS	Transaction Management System
TP	Transmission Provider
TRACE	Transfer Capability Evaluation
TRELSS	Transmission Reliability Evaluation for Large-Scale Systems
TVA	Tennessee Valley Authority
VAR	Volt-Ampere-Reactive
VSA	Voltage Security Assessment
WAMS	Wide Area Measurement System
WSCC	Western Systems Coordinating Council