Insurance and the Nation's Electrical Infrastructure: Mutual Understanding and Maturing Relationships

A Project of the Department of Energy with the Critical Infrastructure Protection Program of George Mason University School of Law

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Participants were asked to submit comments and corrections. Only one participant contacted Dr. Emmons, providing verbal comments suggesting that there are other insurance companies and products that were not included in our list of representative companies.

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I. Executive Summary

The events of September 11, 2001 brought new focus on vulnerability close to home. One of the ways we have thought about vulnerability since the Oklahoma City bombing is in terms of "Critical Infrastructures" – key goods and services for supporting both national and economic security that are, in this country, more often owned and operated by the private sector than by the government.

The Electricity sector's generation, transmission, and distribution of energy throughout the United States has made the protection of the electricity infrastructure a priority. Without electricity, communications systems fail, water systems can no longer operate accurately, and banking collapses. Electricity, in short, is fundamental to preventing cascading failures of several other Critical Infrastructures.

Historically, insurance has been a tool for enhancing safety and security. Fire sprinklers in buildings, for example, were a safety standard adopted and promoted by fire insurance companies in the late 1800s. The sector-specific agency responsible for Energy as a Critical Infrastructure asked the Critical Infrastructure Protection Project at George Mason University School of Law to investigate whether Insurance could be used as a similar infrastructure-protection-enhancement tool relevant to today's threats.

In an effort to understand the relationship between insurance and the critical infrastructure of the electricity sector, the research team conducted interviews with a diverse sampling of electric utility personnel, insurance personnel, sector experts, and economists. In addition, the team performed a literature search. The research team's efforts revealed important data about the insurance and electric utility industries – but no answers. The Electricity sector is a complex web of regulated, unregulated, standard and non-standard, physical and cyber, and state and federal interests. Across the complexity of the sector, however, the research team found one clear message: ***Insurance today is not seen as a tool for protecting the electricity infrastructure.***

The owners and operators of electricity-industry assets make the financial decisions based upon business calculations. Money is only spent by companies when it is believed to be a direct benefit to business. The insurance obtained in the electricity sector is designed to reduce liability, not prevent catastrophic or terrorist related damage to the electricity infrastructure. During the course of the study, electric utilities did not express an active desire for new or enhanced insurance products. The sector representatives appeared to be satisfied with the arrangements currently in place.

The insurance industry is focused on the standard operational functions of business, consumer-type tort lawsuits involved in personal injury, and property damage backing. Insurance offerings in the electricity sector covers generation much more comprehensively than transmission and distribution. Transmission and distribution insurance products are difficult to generate because of jurisdictional issues. Also, -transmission and distribution assets are sufficiently dispersed because it is cheaper to repair or replace than to insure for repair and replacement. Unfortunately, the administrative costs involved with managing and renewing policies make purchasing insurance unappealing in comparison with covering a company's own transmission and distribution losses.

Because insurance is not now seen as an infrastructure-protection tool, several questions stand out. What might be the future role of insurance in enhancing electricity's critical infrastructure protection? Are alternative private incentive systems available that can be used instead of insurance? What should be the government's future role in electricity infrastructure protection?

This paper is designed to serve as a backdrop against which a conference of electricity sector, insurance, and government stakeholders will discuss the outstanding issues and the future of insurance for the electricity sector.

II. Introduction

Insurance is a common mechanism for mitigating business risk. Insurance markets are broadly deployed and generally accepted by both public and private policymakers. In many active insurance markets, insurance providers condition coverage on compliance with specific operational standards. These standards may relate to technology, to personnel training, to security, or to any number of other criteria.

September 11, 2001, raised our nation's awareness of risk within U.S. borders. One of the organizing principles of national response is Critical Infrastructure Protection (CIP). CIP involves identifying the assets that are key to national security and to economic strength, and creating a cohesive strategy for protecting those assets. In the past, national security has been exclusively a governmental responsibility. An important challenge in protecting critical infrastructures is that most critical sectors are owned and operated wholly, or at least in part, by the private sector.

The electricity sector is no exception. Pursuant to deregulation, electricity generation, transmission, and distribution resources in the United States are owned by municipalities, cooperative members and private investors. The owners and operators of electricity-industry assets make financial decisions based upon business calculations. Where they perceive a clear benefit to the business, they spend money; otherwise, they do not.

In this era of heightened threat, there may be a business case for increased expenditure on security, on insurance, or on both to protect electric-industry assets. If so, there in turn may be a role for the insurance industry to play in establishing and assuring a level of consistency in security standards applicable to both physical and cyber operations in the electricity sector.

In September 2004, the George Mason University Critical Infrastructure Protection Program began a study exploring the relationship between insurance and the critical infrastructure of the electricity sector. This paper is the first of two that will result from the study. The purpose of this paper is threefold:

1. to establish a common basis of understanding as to the current relationship between the electricity sector and the insurance sector;
2. to identify other industries or examples in which a similar risk profile may lead to insight regarding the operation of insurance in such arenas; and
3. to present outstanding questions about electricity and insurance industry operations, and about government and industry policies that relate to critical infrastructure protection, that will be addressed at an expert forum convened at the George Mason University Critical Infrastructure Protection Program as part of this project in 2005, the findings of which will result in a second paper.

Parts I and II of this paper establish definitions of the elements involved in the study and discuss the factors that impact the relationship between electricity and insurance. (For research methodology, see Appendices). Subsequent portions of the paper

- move away from the theoretical and introduce key aspects of the makeup of insurance markets;
- describe some important players and influences upon the electricity sector and its relationship to an insurance market; and
- examine policy options and look to potential precedents in other areas.

III. The Electricity Sector

A. The Electric Utility Industry in the U.S.

According to Homeland Security Presidential Directive-7 (HSPD-7), the latest federal document defining critical infrastructures, the electricity sector is key to providing national and economic security. Today, the electric utility industry in the U.S. brings electric service to over 131 million customers – residential, commercial, industrial, and others – throughout the country. To provide this service, over 3,000 utility firms and organizations conduct daily operations, both independently and in cooperation, to ensure the electricity is supplied in a reliable, low cost, and environmentally acceptable manner. The U.S. electric utility industry provides electric service to its customers with the highest reliability of any system in the world.

The majority of electric utility generating plants, steel transmission towers, and wood distribution facilities are above ground for all to see. The U.S. electric utility network has been described as the most complex man-made structure in the world, and in 2000, the National Academy of Engineering selected the U.S. electric utility network as the greatest technical achievement of the past century.[1]

[1] Wulf, William A. (2000). *Great Achievements and Grand Challenges,* The Bridge, Vol 30, No 3 & 4, Fall/Winter, 2000, National Academy of Engineering at http://www.nae.edu/NAE/naehome.nsf/weblinks/NAEW-4STLP8?OpenDocument.

i. Industry Statistics

Utilities: A total of 3,152 electric utilities are serving U.S. customers and can be divided into four broad categories; these are listed below along with the number of utilities in each category.

Utility Type	Number[2]
Investor-Owned Utilities	240
Cooperative Utilities	894
Publicly Owned Utilities	2,009
Federally Owned	9
Total	**3,152**

In addition to the utilities themselves, recent industry deregulation and restructuring has brought thousands of energy marketers, brokers, and independent power suppliers into the industry. This has all occurred since the early 1990s when deregulation and restructuring legislation were initially passed at both the federal and state levels.

Generating Capacity: The installed electric generating capacity of both the electric utilities and independent power producers is over 900 gigawatts. About 62 percent of this capacity is owned by the nation's electric utilities and 38 percent by non-utility organizations. The total number of electric generating units in the U.S. is almost 17,000; these units are installed in over 5,000 power plants. A breakdown of generating units, by the fuel used, is shown below[3].

Fuel Used	Number	Capacity (MW)
Coal	1,535	315,200
Petroleum	3,121	40,000
Gas	6,130	409,400
Nuclear	104	100,900
Hydro	4,145	98,400
Renewables & Other	1,620	19,165
Total	**16,760**	**983,100**

Transmission Lines: To bring electric service to over 131 million customers in the U.S, over 158,000 miles of high voltage transmission lines (230kV and higher) crisscross the nation.

Financial Investment: The electric utility industry is one of the most capital-intensive industries in existence. The total value of the U.S. electric utility generation, transmission, and distribution facilities is approaching $800 billion.

[2] U. S. Department of Energy (2004). *National Infrastructure Protection Plan – Energy Sector Draft.*
[3] U. S. Department of Energy, Energy Information Agency (2003). *Number of Plant-Generators by Energy Source*. http://www.eia.doe.gov/cneaf/electricity/epa/epaxlfile2_2.xls. (last visited Apr 18, 2005).

And the funds paid by customers for electric services each year exceed $240 billion.[4]

ii. Who Seeks Insurance

a. What is Insurance?

Insurance is an arrangement in which parties known as insureds pay premiums to a party called an insurer. The insurer is thereby obligated to pay the insureds an amount specified by an insurance policy if the insureds make claims for losses they experience. Insurance is thus a mechanism for the transfer of risk, here measured directly or indirectly in financial terms, which permits an insured party to replace the uncertainty of possible future losses with a certain payment of a known, fixed amount. An insurance policy thus involves the sacrifice of certain wealth (insurance premiums) in order to avoid the possible loss of wealth, for the insured party; conversely, for the insurer it involves a gain in wealth in return for the prospect of potential large losses.[5]

In other words:

> a risk-averse individual would be willing to pay a premium above the expected value of loss in order to remove risk by purchasing an insurance policy. The maximum an individual is willing to pay above the expected value of loss is known as the *risk premium* (not to be confused with the *insurance premium*, which is simply the price of the insurance policy).[6]

If we assume that a proper measure of social welfare is given by the total of all individual and corporate utilities, it follows that insurance serves to increase social welfare, since the transfer of risk to the risk-neutral insurer increases the utility of the insured without decreasing the utility of the insurer. In addition, risk sharing between risk averse parties may result in their participation in socially desirable ventures, whereas individually they would not be so inclined.[7] For purposes of this investigation, "socially desirable ventures" refers to measures that increase the protection offered for the physical and cyber infrastructure of the electricity sector.

b. Who Buys Insurance?

The purchase of an insurance policy protects against low-probability, undesirable outcomes. Insurance protection is achieved not by offsetting risks in capital markets, but by paying for protection from a company that can pool uncorrelated risks. Some financial economists suggest that, from a shareholder's perspective, publicly-traded firms should not expend resources to hedge. They argue that since shareholders can

[4] U. S. Department of Energy, (2004), *National Electric Delivery Technologies Roadmap, at* http://www.electricity.doe.gov/documents/tech_roadmap.pdf (last visited Apr 18, 2005).
[5] Doherty, Neil A. (1985) CORPORATE RISK MANAGEMENT: A FINANCIAL EXPOSITION, p. 49.
[6] *Ibid., p.* 52.
[7] Shavell, Stephen M. (1987). ECONOMIC ANALYSIS OF ACCIDENT LAW, p. 190.

shed uncorrelated risks by investing in diversified portfolios, they will not reward managers (through higher equity prices) for expenditures to minimize those risks.[8]

Nevertheless, many companies choose to hedge financial risks for a variety of reasons. One is that its managers' comparative advantage lies in their knowledge of the core operations of their company. Hedging allows them to focus their efforts on what they know best—operating their company—while removing extraneous considerations, such as the impact of changing energy prices on their bottom line. Risk of changing weather conditions or fuel prices are beyond the control of utility managers, as are risks of terrorist attack (in the aggregate) and can be viewed as "non-core" risks. By hedging the non-core risks over which they have no control, company managers can focus on maximizing the efficiency of their operations.[9]

Standard economic representations of risk management behavior for a firm assume that the risk manager is a utility maximizer, who has specific information at his disposal prior to the purchase of insurance. This information includes: knowledge of the various loss-inducing outcomes (or contingent states) of the world, the probabilities of these outcomes, actions available to reduce the losses for each outcome, and actions that will reduce the probabilities of each outcome. Under this set of assumptions, the risk manager would view insurance as a vehicle for transferring the risk of loss through an optimal combination of retained risk, risk reduction and insurance.[10]

Electric utilities already have some reason to include insurance in their risk management portfolio. In particular, tax codes may establish incentives for the corporate demand for insurance, and in some cases the corporation's expected tax liability can be reduced through purchasing insurance.

Particular aspects of the tax code that encourage insurance include:

- A casualty loss (e.g. physical equipment in a generating station) is a deductible business expense
- Insurance premiums are deductible business expenses
- Insurance indemnities reduce the deductible loss

[8] This observation may prove a deterrent to insurance hedging in the deregulated electricity environment.
[9] Edison Electric Institute, (2001, Jul). RISK AND RISK MANAGEMENT IN ELECTRICITY MARKETS: A PRIMER 8-9 at http://www.eei.org/industry_issues/finance_and_accounting/finance/restoring_investor_confidence/Risk_and_Risk_Management.pdf (last visited May 25, 2004).
[10] Katzman, Martin T. (1985) *Insurability and the Regulation of Catastrophic Environmental Risks*, Prepared for the Risk Theory Seminar, Nashville, TN April 18-20, p. 4.

With respect to the ability to pass on costs to consumers in case of inability to deliver contracted power services, the corporation must also be concerned about tax code provisions. In most instances the tax code limits the deduction of fines and penalties as ordinary business expenses while the premium a firm pays for liability insurance, indemnifying the firm for penalties and fines in addition to ordinary liability claims, is deductible (although not in all states, including California). This means that the firm's net present value of expected tax liability would likely be reduced with insurance.

Not all firms would choose to insure; in some instances the firm might choose to employ independent consultants to recommend loss-prevention measures and advise management (and bondholders) accordingly.

With respect to insurance and regulated industries (the electric utility sector is of course in transition), where regulators can set prices, they generally set them at levels expected to generate revenues covering the sum of expected costs plus depreciation plus a normal rate of return on the rate base. ***If the firm does not insure against a particular hazard, the expected-cost figure used in establishing allowed revenues and prices must reflect the probability and magnitude of the loss to yield a normal rate of return to the firm's owners. Thus, the regulator must obtain an assessment of the loss distribution.*** In general, this means that a regulated firm would buy significantly more insurance than an unregulated firm with similar characteristics.

The electric power grid was historically operated by separate utilities, each independent in its own control area and regulated by local bodies, to deliver bulk power from generation to load areas reliably and economically. As a noncompetitive,

The electric supply system has over the past decade taken on significantly greater loads (power demands) and has also undergone a makeover from being a highly regulated, vertically integrated utility industry to one that is partially deregulated, far less unified and not as robust and resilient as it was. The generation side is essentially deregulated and operating under an open market set of conditions where competitive price, low operating costs and return on investment are rewarded with profits and bonuses. At the same time the transmission sector remains fully regulated and limited from taking steps to meet growing demand with new capacity by uncertainty in knowing how such investments will be paid for under regulatory bodies that are tasked to see that power is delivered to rate payers at minimum cost.

This dramatic change has played out with the result that the in-place electrical systems assets today are typically being operated very efficiently at close to the limit of available capacity. In this mode, another characteristic of such systems appears. When operated near their capacity, these systems have little margin within which to handle power or load fluctuations. Thus, they are quite vulnerable to being brought down by operating fluctuations that exceed their remaining margins. Shutting down becomes the only way a system element has of protecting itself from severe damage when load exceeds capacity. The loss of a piece of the grid, a section of transmission line, does not end the problem. The inoperable line takes with it the power it was transmitting. A connected power plant, having no connected load must also shut down. In these highly integrated grids, more lines have imbalance problems and more plants sense capacity problems and so also shut down. This cascading spreads very rapidly in many directions and in seconds, an entire sector of the North American grid can be down.

"Confronting The Risks Of Terrorism: Making The Right Decisions", Reliability Engineering and System Safety 86 (2004) 129-176 regulated monopoly, emphasis was on reliability (and security) at the expense of economy. However, this infrastructure faced with deregulation and coupled with interdependencies with other critical infrastructures and increased demand for high-quality and reliable electricity, is becoming increasingly stressed.[11]

c. The Elements of a Classic Insurance Market

The viability of insurance markets depends on a complex interplay of insurance economics, liability law and social policy. However, the elements constituting an effective insurance market *per se* are readily identifiable, and are discussed briefly in this section. Classic characteristics of an insurable market, or incident/risk pool, differ from the classic characteristics of the electricity sector's risk profile. Comparing the two may allow for increased understanding of the current reasoning behind the role insurance has so far played in the electricity sector.

<u>Randomness of the Loss Occurrence</u>
The appeal of insurance to a risk-averse insured lies in the exchange of uncertainty for certainty, and his willingness to pay for the decreased risk. Without uncertainty, or randomness, in the possibility of the various losses there would be no need for insurance because there would be no risk. If individual losses are not truly random and the information is available to the potential insured (but not to the insurer), he would only purchase insurance when it was most needed, making it difficult for the insurer to protect himself against extremely large, possibly ruinous, losses by charging an actuarially fair policy.

<u>Average Loss Amount</u>
If the insurer writes policies for a large number of essentially homogeneous insureds, with truly random and uncorrelated potential losses,[12] the statistical implications for the insurer are twofold:

> the aggregate total risk of the insurer continues to grow, but at a rate less than proportionate to the growth rate of the number of insured parties; and
>
> the statistical distribution of losses for an insured party becomes increasingly bunched around the average liability, or expected loss; in mathematical terms, the standard deviation of losses becomes smaller.
>
> Statistical measures of insured losses for pollution-related events are determined by the joint effects of the probability of damage, probability of a claim, and the probability of award. Changes in the U.S. legal system, particularly environmental legislation and toxic tort law, have resulted in

[11] Amin, Massoud (2001, Jan 31). *Toward Self-Healing Energy Infrastructure Systems*, IEEE COMPUTER APPLICATIONS IN POWER, p. 22, at http://www.ieee.org/portal/cms_docs/newsinfo/self-healing-systems.pdf (last visited May 25, 2005).
[12]Positive correlation implies that losses are interdependent, such as would occur in the case of closely situated facilities, nuclear war or synoptic weather conditions. Negative correlation tends to reduce the risk in the insurer's portfolio, since the effect is to offset the probability of loss by a decrease in the loss probability for the negatively correlated party.

more claims, more extensive claims, and ultimately the potential for larger awards for a given event.[13]

Maximum Possible Loss

It is critical for the insurer to be able to determine his average loss (or payout) per policy; in addition, he must also determine the probability that he will experience total losses greater than his premiums (plus available reserves) will cover. The probability of having losses exceeding this critical solvency level is known as the probability of ruin. In the case of random events, the insurer's risk tends to decrease for a large number of insured parties, since the total loss becomes more predictable and the insurer is increasingly certain that his assets will cover losses. Even if the population of insureds is not truly homogeneous, the results generally apply as long as the losses are random and the relative distribution of insured groups holds regardless of the total number of insured. If the insurance portfolio includes a few policyholders with extremely large loss potential in comparison with the rest of the portfolio, the insurer is presented with the potential for catastrophic loss from a single event. ***Ideally, it is desirable to channel such large exposures into a separate insurance line, but this is not always possible. Alternatives are to charge extremely large premiums, or to have a large deductible provision in the policy or some form of coinsurance, which*** in effect creates a risk-sharing arrangement between the insurer and the insured.

Average Loss Frequency

The average loss frequency, or average period of time between two loss occurrences, is a basic measure used to compute the expected value of losses faced by the insurer. This is determined empirically from the analysis of loss-claims data; ***for new kinds of insured events, insurers may be forced to rely on judgment and conjecture. Insurers are particularly concerned with insured events with a long latency period between losses and claims.*** When this condition is present, the insurer may not be able to determine his risk exposure after a policy has been canceled.

Insurance Premium and the Key Role of Reinsurance

If the insurer has insufficient information concerning the loss potential of the insured parties, or if the individual losses are positively correlated (tend to occur together), it becomes increasingly difficult to develop meaningful statistics for the probability of ruin and the standard deviation of losses. There also is no guarantee that increasing the number of policyholders for correlated losses will reduce the chances of a large loss to the insurer, as occurs with uncorrelated losses. The associated financial risk to the insurer, known as non-diversifiable risk, must either be retained by the insurer or transferred through reinsurance. One expert observes:

> Above all insurability depends on reinsurability as far as major risks and catastrophe exposure is concerned, for which a balancing of risk is only possible with the help of the international reinsurance market.[14]

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[13]Kunreuther, Howard. (Unknown). *The Failure of Environmental Liability Insurance*, prepared for the Geneva Papers on Risk and Insurance.

[14]Nierhaus, Fedor, (1986, April). *A Strategic Approach to Insurability of Risks*, THE GENEVA PAPERS ON RISK AND INSURANCE: ISSUES AND PRACTICE 11, No. 38, pp. 83-90.

Absence of Moral Hazard

The effect of purchasing an actuarially fair insurance premium is to remove all risk to the insured party. As a consequence, the insured has little or no financial incentive to invest additional time or money on loss reduction; the transfer of risk has eliminated the incentive for additional risk evaluation or risk-reduction investment.[15] Even where the benefits of risk-reducing activities exceed the costs, the benefits may accrue to the insurer rather than to the insured. This phenomenon, known as moral hazard, arises when the insured party is in a position to influence risk (i.e. raise or lower the probability of specific losses), and where the insurer has insufficient information to assess the true loss potential and correct premium levels. If the insurer suspects this to be the case, he may be reluctant to offer insurance protection. If, on the other hand, the insurer can, without cost, obtain information about the insured's true risk reduction potential, then it is possible to either price premiums (premium discrimination) to bring about the desired behavior, or to limit or deny coverage in the event of a loss if the insured's actions did not conform to the policy requirements.

Legal Restrictions

Legal restrictions may act more to determine the structure of the market than to define how the insurer acts within that structure. They may have positive or negative effects and can act to either limit or expand the range of insurability. One commentator sums up the role of legal frameworks this way:

> Legal restrictions may be used to reinforce uninsurability for example on the grounds of public policy. They may also be used to enforce insurability in areas insurers otherwise would consider uninsurable. They can be used in the public or national interest to protect a state monopoly insurer from competition or national insurers from overseas competitions and the economy from a drain of hard currency. Finally they can be used in a whole variety of ways to protect the insurance buying public. They can prevent insurers taking too much advantage from the exercise of their professional skill to the detriment of insureds or they may be used to prevent insurers overstretching themselves. Because legal and cover restrictions overlap they are most effective both from insurers and the public policy perspective. When they act in opposition they can, in the extreme, make insurance impossible.[16]

iii. What Insurance Products Is The Electricity Sector Seeking?

During the course of this project, electric utilities did not express an active desire for new or enhanced insurance products. The sector representatives interviewed by the project team appeared to be satisfied with the arrangements they currently have in place. The project team found that insurance currently plays an important but narrow role in the electricity sector, and that insurance is not oriented toward enhancing or promoting the protection of the electricity infrastructure.

[15]With the exception of the influence of reputation effects and transaction costs associated with replacement of a loss.

[16]Aickin, Malcolm, (1986, Apr). *Legal and Cover Restrictions*, THE GENEVA PAPERS ON RISK AND INSURANCE: ISSUES AND PRACTICE 11, No. 39, pp. 158.

Instead, insurance in this sector is geared toward

- standard operations functions of business;
- consumer-type tort lawsuits (slip and fall injuries from falling equipment or power lines); and
- property damage backing (such as roof damage from fallen power lines).

Some insurance in this sector is provided by large, well-known insurers. Other insurance, or insurance-like protection, is offered by a large mutual-risk pool called AEGIS. Most large utilities participate in the AEGIS pool.

Insurance providers and AEGIS do use operational security standards as a benchmark for gauging costs of the insurance they provide. Different providers use different standards, and these standards are generally kept internally (not publicized). What appears to be true – and this is an inference rather than a statistically proven fact – is that ***the insurance obtained in the electricity sector is designed to reduce liability. It is <u>not</u> designed to prevent catastrophic or terrorist – related damage to the electricity infrastructure.***

There are many reasons why this is the case. Most likely are these: the insurance sector sees no profit in infrastructure protection; the electricity sector expects federal finding in the event of major catastrophes (to wit the World Trade Center bombing and 2004's extremely costly hurricane season). The two sectors have been disinclined to explore additional opportunities where these two perceptions hold true.

Some electric power providers suggested that products that were a) "affordable" obviously this figure varied- and b) not subject to price volatility pursuant to covered events might find a market.

iv. Use of Standards for Insurance Purposes

Insurance companies rely upon an organization's compliance with a number of individual standards related to facilities and equipment to provide the foundation for coverage and pricing. With over a century of engineering, design, operating, and maintenance experience, the electric utilities and the industries that serve them have evolved a number of guidelines, standards, codes, and recommended practices to increase reliability and safety and reduce environmental impacts of utility equipment and facilities. These standards, etc. have come about through government regulatory agencies, professional societies, and industry-supported organizations. A brief sampling of these is listed below:

- ASCE American Society of Civil Engineers
- ASME American Society of Mechanical Engineers

- ASTM American Society of Testing and Materials
- EPA U.S. Environmental Protection Agency
- FERC Federal Energy Regulatory Commission
- IEEE Institute of Electrical and Electronic Engineers
- INPO Institute of Nuclear Power Operations
- NERC North American Electric Reliability Council
- NFPA National Fire Protection Association
- OPS Office of Pipeline Safety (U.S. Department of Transportation)
- UL Underwriters Laboratories

The overall objective of these and many other organizations that develop and monitor the standards, codes, guidelines, etc. used by electric utilities is to provide a product that is safe and reliable, that has minimal environmental impact, and is available to everyone at a reasonable price.

v. What Do Insurers Prefer Not to Insure?

Deregulation has had an impact on insurance coverage sought by utilities. According to the AEGIS interview**,** one early result was that some of the more progressive utilities and brokers sought to hedge future risks with Weather Risk Insurance and to develop a Weather Futures Market. The Weather Risk Insurance effort never did develop a large market. In the Weather Futures Market the major players were Enron, Koch, and Equates Ltd, but when Enron went into bankruptcy the Weather Futures market disintegrated.

Weather

While not directly tied to any quantified projection of the impacts of potential global warming, insurers appear to be increasingly reluctant to rely on long-term historical records of weather 'events'. Historically, long-term weather data has been used to help determine weather-related risk and rates for insurance products. However, because of changes in recent weather patterns, AEGIS no longer uses weather data much beyond 5-10 years in evaluating risks. AEGIS has also found that, for instance, the annual hurricane/tropical storm predictions made by the University of Colorado, which are based on long-term records, are no longer accurate enough for their needs.

Terrorism

Catastrophe modelers have refined their terrorism models since introduction of the models and are better able to help insurers assess exposure both at individual locations and for aggregations of exposures. But the models are two years old compared to property models for catastrophe exposures which have been around and have been used and tested over a 15-year period. The engineering sciences have built a large body of data relating to building damage and to peril intensity. As a result, the problem of understanding the severity of building damage given a certain type of terrorist attack is based on existing techniques that are carried over to terrorism models. While uncertainty is still substantial, having a distribution of possible outcomes allows use of statistical techniques that allow insurers to understand the exposure and the required capacity to insure it.

However, many aspects of terrorism risks remain unknown, and may not be quantifiable in the foreseeable future. Although progress has been made on quantifying the potential costs of defined types of attack on locations with specified characteristics, the probabilities associated with occurrence of an attack remain judgmental.

In the wake of Sept. 11, 2001, the Insurance Services Office (ISO) filed optional endorsements to exclude terrorism events resulting in aggregate insurance industry losses over $25 million (See Section 2). The $25 million threshold did not apply to biological-chemical incidents, which were excluded regardless of the size of the event. Nuclear events remained excluded by the policy's war exclusion or nuclear hazard exclusion. The ISO filings were approved in most states, but California, Florida, Georgia, New York and Texas did not grant approval. Terrorism exclusions became commonplace in 2002. The ISO, which offers advisory and filing services for much of the P/C insurance industry, had filed and secured approval for terrorism exclusions on commercial policies in 45 states by February. Most of the insurance industry began to exclude this coverage using these or their own approved forms. According to a July 18, 2002 Council of Insurance Agents and Brokers (CIAB) press release, "terrorism coverage is scarce." An Oct. 25 release also noted higher rates, tougher terms and conditions, and lower capacity.

Congressional passage of the Terrorism Risk Insurance Act of 2002 gave many the right to purchase insurance coverage for losses arising out of acts of terrorism, as defined in Section 102(1) of the Act: In response, ACE Power Products (see later section on insurance products) now offers its customers the right to include these terrorist acts as defined in the Act if ACE is responsible for an otherwise covered event as defined in the policy. To date the response to the offering has been favorable with insureds electing to purchase this additional coverage. ACE also has a stand-alone Property Terrorism coverage, specializing in underwriting for the electric utility industry. This coverage protects against other potential events not covered under the Act, such as actions by an individual who is a U.S. citizen, as well as other differences in conditions that a client may have with other property policies.

B. What Standards Currently Dominate Electricity-Industry Critical Infrastructure Protection?

i. Security and Reliability

Security and *reliability* together enhance *availability* which is a measure of how much time an electric system or network is available to provide service. Generally the equation is:

Availability (%) = (Time Available for Service/ Total Elapsed)*100.

Thus, if you measured something for 20 minutes and it was only able to provide service for 19 of them, you'd have 95 percent availability.

Up into the 1970s, the term *security* for electric utilities had two general meanings: 1) physical security for equipment and facilities – the proverbial gates, guards, and guns; and 2) system operating security – the ability to continue serving customers during natural disasters, equipment failures, and people-caused events. Terrorism against utility facilities was practically, but not completely, unknown. Two examples of terrorism have occurred in California: in the 1970s, the Pacific Gas & Electric Co. had a number of transmission towers dynamited and in the late 1980s, the Los Angeles Department of Water and Power had one of its major aqueduct pipelines from the Owens Valley to Los Angeles dynamited.

Electric system *reliability* has two components - adequacy and security. Adequacy is the ability of the electric system to supply the aggregate electric demand and energy requirements of the customers at all times, taking into account scheduled and unscheduled outages of system facilities. Security is the ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system facilities.

The reliability and security components of electrical services are closely linked; in one sense, they differ only in their predictability: essentially statistical for typical reliability determinations, and generally based on a detailed historical record, while security concerns (both physical and cyber) are far less amenable to modeling and analysis.

IV. From Theory to Practice: the Role of Insurance in the Electricity Sector Today

A. Prominent Electricity Arena Insurers and Products

One of the interesting characteristics of insurance offerings in the electricity sector is that they cover generation much more comprehensively than transmission and distribution. As one risk manager put it, "…look out the window. See all those power lines? None of that is insured."[17]

To some extent, effective transmission and distribution insurance products are difficult to create because of jurisdictional issues. In addition, however, transmission and distribution assets are sufficiently dispersed that it is cheaper to repair or replace than to insure for repair and replacement. Two assumptions may make this especially true:

1. The administrative cost of insurance (obtaining, managing and renewing policies; filing claims) may make insurance unattractive compared to covering a company's own transmission and distribution losses; and

[17] Confidential telephone interview conducted by CIPP NETL Project team, January, 2005.

2. Transmission and distribution equipment failures and damage and subsequent outages are subject to an outage and risk profile that is comfortably self-insured by electricity companies. And this repair and replacement of these facilities is considered part of doing business for a utility. If terrorism or other energy risks significantly alter the vulnerability of transmission and distribution equipment in the future, these assumptions may no longer be valid. Although the transmission and distribution lines are generally not insured, the transmission substations that are an integral part of these systems are insured.

Because of the many special aspects of the electric utility industry, commercial insurance companies have not offered the products to insure the unique power generation, transmission, etc. facilities. However, utilities do insure conventional facilities such as main office buildings, laboratories, and branch offices through commercial insurance firms. Over the years, utilities themselves (electric, gas, water, etc.) have joined together and formed mutual insurance pools to provide insurance coverage for their unique facilities. Briefly described below are examples of the mutual companies that provide insurance products specifically for the electric utility industry.

i. **Associated Electric & Gas Insurance Services Limited (AEGIS)** is a mutual insurance company owned by its policyholders. It was formed in 1975 by 12 utilities to serve utility and related energy industry members. Today, AEGIS has 520 members and offers a wide range of insurance and risk-management products for electric, gas, energy, water, and petroleum exploration and production companies; both investor-owned and public organizations are members and policyholders. The company does not ensure nuclear facilities or pollution/pollution remediation projects. AEGIS products compete with conventional commercial insurance company products but they also provide products that are needed specifically by utilities and energy companies. Listed below is a sampling of the types of insurance products offered to electric utilities by AEGIS:

Non-Energy Operations and Exposures

- Property
- Business Interruption
- Construction Cover
- Liability
- Hull & Cargo
- Protection & Indemnity
- Terrorism & War

Energy Operations and Exposures

- Climate Risk
- Unplanned Generation Outage (Power Shield)
- Extended Power Outage

AEGIS has a large Loss Control Group made up of experienced engineers and others knowledgeable about equipment that conduct on-site inspections of equipment and facilities and make recommendations for customer actions that would reduce potential for outages, etc. and, if followed, has an impact on rates charged for coverage.

ii. **Nuclear Electric Insurance Limited (NEIL)** is a mutual insurance company that is owned by its policyholders. It is incorporated under the Bermuda Insurance Act of 1978 and is a registered insurer under the Captive Insurance Companies Act of Delaware. The company insures nuclear plants and their generating units for the following:

- Long-term interruption of generation
- Decontamination expenses
- Other direct physical loss, including certain premature decommissioning costs
- Certain non-nuclear coverage
- Primary Property Insurance
- Blanket limit for multiple sites

The following is contained within the Mission statement of NEIL: "Our primary goal is to maintain a financial position to cover two full-limit losses, as well as to ensure continuing coverage of nuclear sites."[18]

iii. **ACE Power & Utilities** is the U.S.-based part of the ACE Group of Companies offering customized risk management products for the power generation industry. Products include:

Property Products

- Property Coverage for Power Generation – all-risk coverage for conventional power generation facilities and certain nuclear (small experimental) reactors and related facilities.
- Construction Coverage – builders risk for construction projects

Power Products

- PowerBacker^{SM} – coverage for long-term, unplanned generator outages
- WeatherBacker^{SM} – indemnify against financial impact of extreme weather events; WeatherBacker^{SM} (T&D) – available to protect against damage from ice storms, hurricanes, and wind storms. With limits of up to $100 million, the ACE PowerBacker^{SM} protects generation owners against adverse financial consequences that result when one or more generating units are out of commercial operation for long periods.[19]

iv. **Available Products**

In the mid-90s ACE created replacement power insurance in response to the extreme market volatility in the Midwestern United States. ACE started with insuring one customer in 1998 and grew to over 70,000 megawatts concurrently by the summer of 2000. As volatility and price swells have spread to other

[18] Nuclear Electric Insurance Limited (2003). *Mission Statement*, ANNUAL REPORT, at http://www.nmlneil.com/mission.html (last viewed May 30, 2005).

[19] This product uses the definition of "unplanned outage" that is set forth by the IEEE.

regions of the country and world, the product has followed, offering protection to customers in the U.S., United Kingdom, Australia and Canada. Coverage has been used by any size customer from 2 megawatt cogeneration facilities to 12,000 megawatt and up power systems.

In short, ACE PowerBacker^{SM} Replacement Power Insurance was designed to bridge physical exposures of Unplanned Outages and the financial exposures of volatile electricity spot markets. The product has been compared to a contingent call option, with loss measurement starting immediately.

B. Other Stakeholders in the Electricity-Insurance Equation

Questions about the role of insurance in the electricity sector can not be considered in isolation. Both sectors exist within, and are affected by a vast, interconnected web of stakeholders with meaningful affects on the system. While it is not possible to map that web in this paper, this section details the major participants in the complex dynamic.

i. National Energy Policy Development Group (NEPD)

The NEPD was established in 2001 to "develop a national energy policy designed to help the private sector, and, as necessary and appropriate, State and local governments, promote dependable, affordable, and environmentally sound production and distribution of energy for the future." In one of its first initiatives, the NEPD recommended that "(t)he President direct the Secretary of Energy to work with FERC to improve the reliability of the interstate transmission system and to develop legislation providing for enforcement by a self-regulatory organization subject to FERC oversight."

ii. US Department of Energy (DOE)

The Department of Energy has as one of its strategic goals "to protect our national and economic security by promoting a diverse supply and delivery of reliable, affordable, and environmentally sound energy." The DOE Office of Energy Assurance (EA) works toward this end in close collaboration with State and local governments and the private sector to protect the nation against severe energy supply disruptions. In addition to identifying energy system critical components and interdependencies, EA also recommends actions to correct or mitigate vulnerabilities.

iii. Federal Energy Regulatory Commission (FERC)

The Federal Energy Regulatory Commission is an independent agency that regulates the interstate transmission of natural gas, oil, and electricity, along with regulating natural gas and hydropower projects. With respect to infrastructure regulation, the Commission recently updated its strategic plan and created a new reliability division to ensure the reliability of the bulk electric system.

The Federal Energy Regulatory Commission recently supplemented its April 2004 policy statement on power system reliability by affirming that "Good Utility

Practice" required under the Commission's open-access transmission tariff includes compliance with new reliability standards adopted by the North American Electric Reliability Council (NERC).

The Commission's order supplementing the reliability policy statement followed the NERC Board of Trustee's approval of Version 0 for reliability standards, which became effective April 1, 2005. According to FERC Chairman Pat Wood III, "NERC has taken an important step toward delivering on the promise of maintaining full grid reliability. We are counting on active NERC compliance audits to assure these standards are vigorously implemented."

The Commission's April 2004 policy statement on power system reliability concluded that "NERC's reliability standards should represent a floor for grid operator and bulk system participants' reliability efforts, and not a ceiling. Utilities and other entities involved in transmission system reliability should strive toward achieving reliable transmission service and not simply act with the aim of meeting the minimum requirements that have been set forth in manuals and standards."

The Commission strongly supports legislative reform to provide a clear Federal framework for developing and enforcing mandatory reliability rules. In the interim, the Commission is taking steps within its existing authority to promote greater reliability of the United States' bulk power system and its operation and to support industry efforts to improve the current voluntary industry based approach.

The policy statement further said: "In sum, the Commission expects public utilities to comply with NERC reliability standards and to remedy any deficiencies identified in NERC compliance audit reports and recommendations. The Commission will consider taking utility-specific action on a case-by-case basis to address significant reliability problems or compliance with Good Utility Practices, consistent with its authority. A failure to comply with such industry standards could in some circumstances affect Commission determinations as to whether Commission jurisdictional rates are just and reasonable. For example, it may be appropriate to deny full cost recovery in circumstances where a transmission provider fails to provide full reliability of service."

iv. North American Electric Reliability Council (NERC)

NERC's mission is to ensure that the bulk electric system in North America is reliable, adequate and secure. Since its formation in 1968, NERC has played a major role in protecting the electric system by serving as the focal point for coordinating information exchange on critical infrastructure issues between the electricity industry and the federal government. Through NERC, government and industry work together to protect the electricity infrastructure from physical and cyber attacks.

The U.S. Department of Energy (DOE) designated NERC as the electricity sector coordinator for critical infrastructure protection, and the National Infrastructure

Protection Center (NIPC) asked NERC to be the Information Sharing and Analysis Center for the electricity sector. NERC also works closely with the Department of Homeland Security (DHS) to ensure that the critical infrastructure protection functions vital to the industry are fully integrated and coordinated with the Department.

v. The National Association of Regulatory Utility Commissioners (NARUC) State Public Utility Commissions

Once electricity projects become operational, safety is regulated, monitored and enforced at the state level where the project resides (except operational hydropower projects, which remain under FERC jurisdiction). Rather than consider statutes and regulations of individual State Public Utility Commissions, the positions and policies of Commissions are generally represented by the National Association of Regulatory Utility Commissioners (NARUC), which is a non-profit organization founded in 1889. Its members include the governmental agencies that are engaged in the regulation of utilities and carriers in the fifty States, the District of Columbia, Puerto Rico and the Virgin Islands. NARUC member agencies regulate the activities of investor-owned telecommunications, electric, natural gas, and water and wastewater utilities.

NARUC's mission is to serve the public interest by improving the quality and effectiveness of public utility regulation. Under State law, NARUC members have the obligation to ensure the establishment and maintenance of utility services as may be required by the public convenience and necessity, and to ensure that such services are provided at rates and conditions that are just, reasonable and nondiscriminatory for all consumers.

NARUC maintains a number of standing committees covering electricity, gas and critical infrastructure issues. These committees exam and develop policy resolution that serve as “guidance” for State Public Utility Commissions. The NARUC Ad Hoc Committee on Critical Infrastructure has a number of responsibilities, which include the following:

- Identifying the appropriate role(s) of regulatory commissions with respect to the security of the Nation’s electric, natural gas, telecommunications, and water infrastructures from threats of terrorism.
- Addressing issues related to the security of the Nation’s electric, natural gas, telecommunications, and water infrastructures from threats of terrorism.
- Ensuring state commissions have the information and tools needed to work with the industries to keep critical infrastructure secure.
- Encouraging states to have current and up-to-date plans in place that will allow for rapid recovery from natural or man-made disruptions to service.
- Ensuring commissions are integrated into their state and federal critical infrastructure protections and restoration plans.
- Recommending additional activities the Committee believes will enable commissions to best ensure the continued provision of utility service in the face of terrorist activity.

An increasingly high-priority policy objective of NARUC involves encouraging State Public Utility Commissions to approve appropriate applications by electric and gas companies subject to their jurisdiction to recover prudently incurred costs necessary to further safeguard the reliability and security of the energy supply and delivery infrastructure. Some utilities are making substantial investments in new enhanced security measures and back-up systems, including investments in response to federal requirements. State Public Utility Commissions may be asked to approve recovery of these investments and to make decisions of the prudence of these investments. Some have already done so.

vi. Edison Electric Institute

Edison Electric Institute (EEI) is the trade association for U.S. shareholder-owned electric companies, and serves international affiliates and industry associates worldwide. EEI U.S. members serve almost 95 percent of the ultimate customers in the shareholder-owned segment of the industry and nearly 70 percent of all electric utility ultimate customers in the nation, and generate over 70 percent of the electricity produced by U.S. electric utilities.

Organized in 1933, EEI works closely with all of its members, representing their interests and advocating equitable policies in legislative and regulatory arenas. In its leadership role, EEI provides advocacy, authoritative analysis, and critical industry data to its members, Congress, government agencies, the financial community and other opinion-leader audiences. EEI provides forums for member company representatives to discuss issues and strategies to advance the industry and to ensure a competitive position in a changing marketplace.

vii. American Public Power Association

The American Public Power Association (APPA) is the service organization for the nation's more than 2000 community-owned electric utilities that serve more than 43 million Americans. It participates in a wide range of legislative and regulatory forums representing its member utilities.

It was created in 1940 as a non-profit, non-partisan organization. Its purpose is to advance the public policy interests of its members and their consumers, and provide member services to ensure adequate, reliable electricity at a reasonable price with the proper protection of the environment.

APPA is governed by a regionally representative Board of Directors.

viii. National Rural Electric Cooperative Association

National Rural Electric Cooperative Association (NRECA) is the national service organization dedicated to representing the national interests of cooperative electric utilities and the consumers they serve. The NRECA Board of Directors oversees the association's activities and consists of 47 members, one from each state in which there is an electric distribution cooperative.

Founded in 1942, NRECA was organized specifically to overcome World War II shortages of electric construction materials, to obtain insurance coverage for newly constructed rural electric cooperatives, and to mitigate wholesale power problems. Since those early days, NRECA has been an advocate for consumer-owned cooperatives on energy and operational issues as well as rural community and economic development.

NRECA's more than 900 member cooperatives serve 37 million people in 47 states. Most of the 865 distribution systems are consumer-owned cooperatives; some are public power districts. NRECA membership includes other organizations formed by these local utilities: generation and transmission cooperatives for power supply, statewide and regional trade and service associations, supply and manufacturing cooperatives, data processing cooperatives and employee credit unions**.**

ix. Electric Power Research Institute (EPRI)

The Electric Power Research Institute (EPRI) was established in 1973 as an independent, non-profit center for electricity and environmental research. EPRI's collaborative science and technology portfolio now spans every aspect of power generation, delivery and end-use, drawing upon a world-class network of scientific, engineering and technical talent. EPRI's clients represent over 90% of the electricity generated in the US. International client participation represents over 10% of EPRI's program investment.

Through the power of collaboration, EPRI is able to leverage the collective resources of its clients to address the industry's toughest and most critical challenges related to generation, delivery and end-use, with a special focus on safe, reliable, cost-effective electricity and environmental stewardship.

V. The Impact Factors

A. Regulation v. Deregulation

While the previous section described organizational players affecting the complex relationship between the electricity sector and Insurance, this section illustrates substantive issues and developments that affect the Electricity landscape and incentive structure today.

The electricity sector has been subject to marked deregulation in the past 15 years leading to increasing competition of electric generation in the wholesale sector. A number of individual investor-owned utilities have restructed by separating the unregulated generation part of the company from the regulated transmission and distribution areas.

Public policy actions directed at improving protection of critical infrastructure are constrained by the private ownership of the majority of critical infrastructure assets in the country. In this regard, critical infrastructure policies are similar to other policies implemented through economic and social regulation of private industry. In the case of critical infrastructure in the electric power industry, policies must be made in the context of the state and federal regulation of the industry.

Under traditional modes of economic regulation for the electric power industry, motivating protection of critical infrastructure would have been relatively straightforward - lines of authority to set policy were relatively clear and regulators relied upon a well-understood set of tools and procedures to compensate industry for the costs of meeting policy objectives. Restructuring of the electric power industry has changed the levers available to policymakers as they seek to improve protection of critical infrastructure.[20] Restructuring has also resulted in significant jurisdictional disputes between federal and state regulators concerning the electric power industry.

B. Deregulation and Incentives to Upgrade

Although no empirical data are available on the question of whether ownership structures affect critical infrastructure protection investment in the electricity sector, application of well known economic principles would lead to the conclusion that ownership and management structures have an impact on business decision-making. The varying ownership structures that have arisen pursuant to deregulation have varying incentive profiles. Municipally owned utilities may perceive little value in purchasing insurance since the municipality (or other government entity, such as FEMA) would have to bear the cost of incidents (outages) in most situations.

Cooperatives or "coops," might have incentives to carry moderate levels of insurance. Both municipal and cooperative utilities appear to have the similar levels of FEMA support (disaster recovery money, support for mitigation programs). In the case of municipals, this may create an implicit "fall-back" on cost recovery in the taxing and borrowing ability of the local government, thereby lessening interest in insurance (a construct not available to coops). Investor-owned utilities would seem to have the most to lose from incidents and thereby the highest incentive to purchase insurance – but they are also governed by the business analysis typical of other profit driven entities, and therefore have probably the lowest likelihood of investing in insurance (absent a clear showing of profit maximization from such an investment). Merchant Power Plants have a profile similar to investor-owned utilities.

[20] On restructuring of the electric power industry, see Paul L. Joskow (1997), *Restructuring, Competition, and Regulatory Reform in the U.S. Electricity Sector*, JOURNAL OF ECONOMIC PERSPECTIVES, 11(3), pp.119-138. *See also*, ENERGY INFORMATION ADMINISTRATION, THE CHANGING STRUCTURE OF THE ELECTRIC POWER INDUSTRY 2000: AN UPDATE, *at* http://www.eia.doe.gov/cneaf/electricity/chg_stru_update/update2000.html (Additional detail, definitions and statistical information on restructuring).

The EPAct addressed two critical impediments to competition left under PURPA. The first was the creation under EPAct of exempt wholesale generators (EWGs). EWGs are merchant power plants and are allowed to engage in the business of selling energy at wholesale while being exempted from PUHCA. The second issue, that of access to transmission lines, was addressed by FERC in 1996 when it issued Order No. 888. Order No. 888 requires utilities to unbundle their transmission service function from their generation and power-marketing functions and to sell them separately. In fact, utilities owning transmission lines must purchase transmission service from themselves at the same rate as they sell to external entities.[21]

The resulting system is one in which merchant power plants may generate power and then sell it wholesale on the open market to whomever offers the best price. Order No. 888 then allows the plant to transmit the energy to the purchaser wherever they are for a fee, negotiated with transmission facility owners. It allows the market to dictate prices and thereby purports to create efficiencies in generation and therefore a lowering of overall prices. Between 1992 and 2004, generators other than traditional utilities added about 190,000 MW of generating capacity in the United States. These additions represent approximately 70 % of all new generation during that period.[22] In June 2004, total U.S. net generation of electricity was 342 billion kWh. Competitive power suppliers generated 104 billion kWh of sales in the wholesale market, or 31% of total generation for the month.[23]

Regarding cost savings, an independent analysis done by Boston Pacific for the Electric Power Supply Association covering the introduction of competition from 1985 through 2001, found inflation-adjusted electricity prices declined, on average, by 31% for residential customers and 35% for commercial/industrial customers. The Electric Power Supply Company Association "…is the national trade association representing competitive power suppliers, including generators and marketers.[24] Similarly a 2001 Department of Energy study of the nation's transmission grid found $13 billion savings per year in electricity costs created by wholesale market competition. The same study found that competition-induced relief from congestion in California, PJM, New York and New England could save consumers as much as $500 million per year.[25] The General Accounting Office estimated

[21] 21 [1] See Shell Pipeline Company LP, Docket No. IS04-171-000, FEDERAL ENERGY REGULATORY COMMISSION - COMMISSION, 106 F.E.R.C. P61,187; 2004 FERC LEXIS 384, February 27, 2004, and ORDER ACCEPTING SECURITY SURCHARGE, SUBJECT TO CONDITION, Docket No. IS03-475-000, FEDERAL ENERGY REGULATORY COMMISSION - COMMISSION, 104 F.E.R.C. P61,332; 2003 FERC LEXIS 1931, September 30, 2003, BP Pipelines (North America Inc.), 105 F.E.R.C. P61384, 2003 FERC LEXIS 2607 (F.E.R.C. 2003), Florida Gas Transmission Company, 105 F.E.R.C. P61171, 2003 FERC LEXIS 2177 (F.E.R.C. 2003), ORDER ACCEPTING SECURITY SURCHARGE, SUBJECT TO CONDITION, 104 F.E.R.C. P61332, 2003 FERC LEXIS 1931 (F.E.R.C. 2003), Colonial Pipeline Company, 100 F.E.R.C. P61035, 2002 FERC LEXIS 1401 (F.E.R.C. 2002), San Diego Gas & Electric Company, 99 F.E.R.C. P61387, 2002 FERC LEXIS 1350 (F.E.R.C. 2002), Southern LNG Inc., 98 F.E.R.C. P61088, 2002 FERC LEXIS 204 (F.E.R.C. 2002), Williston Basin Interstate Pipeline Company, 97 F.E.R.C. P61369, 2001 FERC LEXIS 3070 (F.E.R.C. 2001), Southern LNG, Inc., 97 F.E.R.C. P61254, 2001 FERC LEXIS 2856 (F.E.R.C. 2001)

[22] Electric Power Supply Association (EPSA). (2004). at *www.epsa.org/competition/quick_facts_mp.cfm*, source: EIA, Form EIA-860, Annual Electric Generator Report.
[23] Ibid, (2004, Sep). EPSA and Energy Information Administration, ELECTRIC POWER MONTHLY.
[24] Ibid. *www.epsa.org/about/overviews.cfm*. (Accessed 03/18/05).
[25] U.S. Department of Energy. (2002, May). NATIONAL TRANSMISSION GRID STUDY.

that if the federal government purchased its electricity on a competitive basis, it could save from $1 billion to as much as $8.2 billion over the 18 year period 1998-2015.[26] However, once again we have a scenario where the utilities themselves do not hold the generating infrastructure and so must look to diversification as a form of insurance.[27]

i. Merchant Power Plants

Merchant power plants generate electricity for sale on the open wholesale market. They arose out of the deregulation of the power industry which began with the Public Utility Regulatory Policies Act of 1978 and culminated in the Energy Policy Act of 1992.

Between 1935 and 1978 the regulatory framework of the electricity industry remained virtually unchanged. The Public Utilities Holding Company Act (PUHCA) passed in 1935 codified the view of the industry as a natural monopoly and "defined the nature of federal electric utility regulation until the passage of the Public Utility Regulatory Policies Act of 1978 (PURPA)".[28] However the onset of the energy crisis (including OPEC-driven oil embargoes), created concern for the security and reliability of the nation's power supply. Additionally, questions began to emerge regarding the soundness of the view of the industry as a natural monopoly. The upshot of these machinations was the enactment of PURPA as a way to diversify electric utilities' sources of power as well as inject a measure of efficiency through competition into the system.

PURPA created new power generating entities which it called Qualifying Facilities (QFs). QFs were a first step towards introducing competition into the electricity industry, but the impact was fairly weak because QFs did not have access to the incumbent utility's transmission lines. As a result, sales were only possible to the local utility.[29] In terms of critical infrastructure security, the QFs were essentially a physically proximate extension of the utilities themselves. A disturbance or having a single QF out-of-service would not stop the utility from providing power since QFs comprised only a small percentage of the utility's generating capacity. However if a disturbance or threat event were large enough to destroy the entire local region, then the multiplicity of QFs would not help because of their lack of remoteness. Additionally, because the QFs were not owned by the incumbent utilities, the utilities did not have the opportunity to take

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[26] U.S. General Accounting Office (1998, Feb 25). FEDERAL ELECTRICITY: RETAIL COMPETITION COULD CREATE SAVINGS FOR THE DEPARTMENT OF DEFENSE.

[27] For additional information see: Southeastern Association of Regulatory Utility Commissioners (SEARUC). (2002, Nov 25). *The Benefits and Costs of Regional Transmission Organizations and Standard Market Design in the Southeast.* At http://ir.crai.com/ireye/ir_site.zhtml?ticker=CRAI&script=460&layout=-6&item_id=359304
EPSA Comments at http://www.epsa.org/forms/documents/DocumentFormPublic/view?id=305000000459

[28] Abel, Amy. (1998, May 4). *Electricity Restructuring Background: The Public Utility Regulatory Policies Act of 1978 and the Energy Polict Act of 1992.* CRS REPORT FOR CONGRESS, p. 2.

[29] Kelly, Suedeen. (2001). *Domestic Energy Policy In The Era Of Electric Industry Deregulation: The Future Of Gas, Coal, Railroad, Nuclear Power, Renewables, And Oil Industries…And Their Executives And Lawyers,* originally published by the ROCKY MOUNTAIN MINERAL LAW FOUNDATION, *The Proceedings Of The 47th Annual Rocky Mountain Mineral Law Institute.*

direct steps to protect the QF infrastructure. For the utilities, insurance could take the form of a diversified stable of QFs rather than the “hardening” of any specific QF. However the degree to which diversification of location was hampered by a lack of transmission access marked the vulnerability with which the utilities would be forced to live. QFs were usually very small and their presence or absence did not change a utility’s capability to serve their customers. Many QFs were based upon small renewable technologies (*e.g.* solar, wind or small hydro).

Congress moved deregulation forward after increased pressure was brought to bear in the 1980s. Since only QFs could avoid regulation under the 1935 Act, new non-utility generators found it difficult to enter the market. Yet increased competition was envisioned as a mechanism to provide new generation capacity at lower cost.[30] As a result, in 1992 the EPAct was passed.

ii. Generation

The effects of restructuring vary across the main subsectors of the power industry: generation, transmission and distribution differ in ways that will affect the manner in which a company can expect to recover costs associated with critical infrastructure protection. Almost 60 percent of generation resources are owned by electric utilities, most of which is owned by investor-owned utilities with rates regulated by states.[31] In principle, the costs of critical infrastructure protection for generation resources are recoverable through regulated rates, subject to the usual state regulatory principles for cost recovery.[32]

Over 40 percent of generation capacity is owned by independent power producers or other non-utility companies.[33] These producers sell to:

a. distribution utilities serving residential, commercial and industrial customers, and
b. directly to industrial or large commercial customers and investor-owned utilities.

The category "distribution utilities" includes distribution companies unbundled from former vertically-integrated utilities, municipals, and cooperatives. These utilities may own some of their own generation, but make economic purchases from the wholesale power markets to cover the rest of their needs. FERC regulations require that generators be provided non-discriminatory "open access" to interstate transmission systems and are included, in part or in whole, in FERC Orders No. 888, Order No. 889, and Order No. 2003.

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[30] Ibid.

[31] U.S. Department of Energy, Energy Information Administration. (2003). *Electricity Power Annual*. Electric utilities include investor-owned electric utilities, municipal and State utilities, Federal electric utilities, and rural electric cooperatives. Available online: http://www.eia.doe.gov/cneaf/electricity/epa/epa_sum.html.

[32] See the cost recovery discussion in section B, Distribution, immediately below.

[33] Independent power producers hold about 35 percent of capacity; industrial and commercial combined heat and power plants represent about 7 percent of capacity. See Table 2.3. Existing Capacity by Producer Type, 2003; *Electricity Power Annual, 2003*. Online: http://www.eia.doe.gov/cneaf/electricity/epa/epat2p3.html.

The revenues collected by independent utility and merchant firms depend primarily on market prices for power and other services. Such firms do not have ready access to expenditure-based cost recovery guarantees. However, as revenue is directly related to output (product sold), such firms would usually have clear incentives to make investments to protect assets and ensure continued service.

iii. Distribution

Even with restructuring, local distribution assets remain regulated by the states. As such, prudent expenditures are recoverable through state-regulated retail rates. A survey of cost recovery practices commissioned by the National Association of Regulatory Utility Commissioners concluded that state regulators were committed to allowing cost recovery of critical infrastructure costs, and regulators generally felt that existing cost recovery protocols should be sufficient to allow for cost recovery.[34] In some states, new legislation or regulatory proceedings were developed to address cost recovery for security-related investments. However, all the procedures which allow early recovery of funds ultimately will be incorporated into the next rate proceeding for the utility. The NRRI report specifically notes that insurance can play a role in critical infrastructure expenditures.[35] Michigan law, for example, specifically includes the cost of insurance as among the costs that can be recovered in rates, and also states that recovery of costs by net of any insurance proceeds. The NRRI report recognizes that, "Insurance can provide both an incentive and a risk management tool for utilities," and observes that insurance providers can require that certain actions are undertaken by utilities prior to obtaining insurance coverage.[36]

iv. Transmission

The consequences of restructuring for transmission has been more complicated than for either distribution or generation assets. In principle, transmission assets are almost inherently involved in interstate commerce and under federal jurisdiction, providing service under FERC-regulated rates. However, in practice, much of the cost of constructing, operating and maintaining transmission assets is recovered through state-jurisdictional retail rates, and therefore state policies and state regulatory oversight have significant effects. Also, transmission siting and other policies affecting transmission assets are generally determined at the state level.

Federal regulators have sought to assure transmission owners that costs associate protecting critical infrastructure will be recoverable through regulated rates. On September 14, 2001, FERC issued the following statement:

> The Commission understands that electric, gas, and oil companies may need to adopt new procedures, update existing procedures, and install facilities to further safeguard their electric power transmission grid and

[34] Lawton, Raymond, John Wilhelm, Robert E. Burns, Scott Potter, and Joe McGarvey. (2004, July). *Model State Protocols for Critical Infrastructure Protection Cost Recovery*, National Regulatory Research Institute, Prepared for the NARUC Ad Hoc Committee on Critical Infrastructure (NRRI report)
[35] NRRI report, p. 22-23.
[36] NRRI report, p. 23.

> gas and oil pipeline systems. The Commission is aware that there may be uncertainty about companies' ability to recover the expenses necessary to further safeguard our energy infrastructure, especially if they are operating under frozen or indexed rates. In order to alleviate this uncertainty, the Commission wants to assure the companies we regulate that we will approve applications to recover prudently incurred costs necessary to further safeguard the reliability and security of our energy supply infrastructure in response to the heightened state of alert.[37]

In response to the August 2003 blackout, FERC reaffirmed its commitment to allowing recovery for prudent expenditures to increase system reliability.[38]

C. Re-regulation?

The primary goal of industry restructuring efforts was to increase competition in the wholesale power marketplace and bring about lower costs for energy consumers. The Energy Policy Act of 1992 sought to boost that competitiveness by providing FERC with clearer authority to require that transmission owners allow third-party energy suppliers and consumers nondiscriminatory and open access to the transmission grid. In Order No. 888 and subsequent rulings, FERC provided a regulatory framework to support "open access" that resulted in a significant increase in the use of the transmission grid to support competitive power transactions.

However, some industry analysts have argued that through efforts to promote regional transmission organizations[39] and a standard market design,[40] FERC has now gone beyond establishing a foundation for competitive markets, and is instead becoming increasingly prescriptive about how buyers and sellers conduct their trades. The consequence is that FERC seems to be re-regulating the industry in the name of promoting de-regulation and competition.[41]

The practical consequence of FERC's efforts to organize coordinated power markets has contributed to significant political and regulatory uncertainty. Regulatory uncertainty, in turn, raises concerns about the stability of regulatory commitments to ensure cost recovery, increasing perceived investment risks.

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[37] Federal Energy Regulatory Commission, *Statement of Policy on Extraordinary Expenditures Necessary to Safeguard National Energy Supplies*, 96 FERC ¶ 61,299 (2001).
[38] Federal Energy Regulatory Commission, *Policy Statement on Matters Related to Bulk Power System Reliability*, 107 FERC ¶ 61,052 (2004).
[39] *Regional Transmission Organizations*, Order No. 2000, 65 Fed. Reg. 809 (January 6, 2000), FERC Stats. & Regs. 31,089 at 31,226 (2000), *order on reh'g*, Order No. 2000-A, 65 Fed. Reg. 12,088 (February 25, 2000), FERC Stats. & Regs. 31,092 (2000), *aff'd*, *Public Utility District No. 1 of Snohomish County, Washington v. FERC*, 272 F.3d 607 (D.C. Cir. 2001).
[40] *Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design*, Notice of Proposed Rulemaking, 67 Fed. Reg. 55,452 (Aug. 29, 2002), FERC Stats. & Regs. 32,563 (2002).
[41] For one perspective see Jay A. Morrison, (2004, Dec. 15-16). *Competing Industry Visions*, Paper presented at *Electricity Transmission in Deregulated Markets: Challenges, Opportunities, and Necessary R&D Agenda*, (Carnegie Mellon University.

D. Jurisdiction Problem

As noted in the prior discussion, overlapping federal and state regulatory authority complicates efforts to establish policies governing recovery of critical infrastructure costs. While wholesale transmission rates are FERC jurisdictional, a significant portion of transmission revenues are paid through state regulated and approved retail rates. Many complementary critical infrastructure policy questions – interactions between electric power service, emergency services, and public safety – further entwine utility decision-making with state and local government relationships. In part, the jurisdictional conflict arises from policy decisions made in the Federal Policy Act in the 1930s, a time when most electric transmission was entirely within state boundaries and interstate transmission was not a significant issue for either the industry or state and federal policymakers.

Adding to the confusion, a revised version known as NERC 1300 is about to supersede NERC 1200. The new standard will extend coverage beyond distribution and transmission companies to also include power generators. And NERC 1300 carries enforcement provisions and penalties.

The deadline for compliance with NERC 1300 will probably be March 2007, Sevounts says. The North American Electric Reliability Council developed the security standards when the Federal Energy Regulatory Commission made it clear that federal regulations would be enacted and enforced if the industry organization didn't step up to the plate on a voluntary basis.

"FERC is watching," Sevounts says. "The standards are voluntary at this point. But if the industry doesn't comply, FERC will come after them or impose government regulations. "For example, FERC would go after a company that causes a blackout due to noncompliance with NERC cyber-security standards, Sevounts says. A year ago, he says, a lot of utilities weren't paying much attention to NERC 1200. Since then, more have begun working to bring their operations into compliance.

The coming of NERC 1300 has sparked some of the increased activity. NERC 1300 "covers more areas of security and sets a higher bar" than 1200, Sevounts says. "If you're going to have to comply with 1300, you might as well comply with 1200 first," Sevounts cites as the reason spurring companies. NERC 1300 attempts to address security issues in areas such as patch management. When a vulnerability is discovered in an information technology system, a "fix" or "patch" provided by the software designer is immediately applied to the system.

The problem, Sevounts says, is that in the case of information technology systems controlling critical networks like power grids, it's virtually impossible to apply patches. The process usually requires shutting down, restarting and testing to validate that the patch works. And that can't be done with systems that must operate continuously.

"This is why a lot of companies are looking for alternative security measures, like a gateway to stop intrusions before they could exploit vulnerabilities," Sevounts says. In one incident at the Davis-Besse nuclear power plant in Ohio in January 2003, the "Slammer Worm" was able to get into the plant's corporate and operating systems because they were connected to external networks via a firewall without access control policies. The network was overloaded and the server went down, taking the plant's computers offline.

Fortunately, the nuclear plant happened to be down for maintenance at the time, "but that highlighted the security issues," Sevounts says.

VI. Potential Precedents Upon Which To Draw

A. Risk Management in the Nuclear Energy Sector and the Price-Anderson Act

After World War II, nuclear energy began to emerge as a valuable source of energy. In 1954, Congress Passed the Atomic Energy Act, allowing and encouraging private industry to develop nuclear energy. Upon the realization that the development of nuclear power could lead to catastrophic damages, companies began backing out of the industry, afraid of the potential liability. Congress responded in 1957 with the Price-Anderson Act (the Act),[42] which lowered the requisite amount of insurance that a nuclear facility would be required to carry in return for civil liability caps in the event of a nuclear disaster.

As the Nuclear Regulatory Commission (NRC) described, the Act had two main goals: 1) to ensure that adequate funds would be available to the public to satisfy liability claims in a catastrophic nuclear accident; and 2) to permit private sector participation in nuclear energy by removing the threat of potentially enormous liability in the event of such an accident.[43] When licensed by NRC, nuclear facilities are entitled to the benefits of the Act.

Under the Act, facilities are required to maintain a fixed amount of coverage for each reactor. In 1988, this figure was set at $63 million per reactor, to be adjusted for inflation. The current figure is $300 million in mandatory coverage. In the case of an incident, the general insurance is paid out first, and in the event that the damages exceed that figure, each of the nations other reactors is forced to pay into a pool to cover the damages. As adjusted for inflation, each reactor would be forced to contribute up to $95.8[44] million. With 103 reactors across the country, the total liability of the nuclear industry under the Act, when combining the pooled funds with the commercial insurance comes to just over $10 billion.[45]

The continued support of the Price-Anderson Act is a heated topic every few years. All currently operating nuclear facilities are subject to the Price-Anderson Act, even if it were to expire. Thus, many organizations concerned that the Act limits liability too far, are pushing to allow it to expire, forcing new forming facilities to operate under regular market conditions, and not under what they feel to be an unjust subsidy. According to, the Calculation of Reactor Accident Consequences (CRAC-2), a report published by Congress on Nov. 1, 1982, following the 1979 Three-Mile Island incident, the estimated damages from a severe blast could total as much as $314 billion, which adjusted for inflation could surpass $560 billion.

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[42] Price-Anderson Act, 42 U.S.C. § 2210 (1957).
[43] *See* Statement by the U.S. Nuclear Regulatory Commission to the Senate Committee on Energy and Natural Resources Concerning Price-Anderson Act Renewal (May 24, 2001) *at* http://www.nrc.gov/reading-rm/doc-collections/congress-docs/congress-testimony/2001/PriceAh4.pdf.
[44] NRC updated figures as of Aug. 4, 2003.
[45] Price-Anderson Act: The Billion Dollar Bailout for Nuclear Power Mishaps (September 2004) *at* http://www.citizen.org/documents/priceandersonbackgrounder.pdf#search='%24560%20billion%20nuclear'

Opponents also feel that the Price-Anderson Act was designed to be a temporary solution to starting business in a technologically new area, where risk was largely unknown. As the years have passed, however, the risks and remedies are well known, making the subsidy unnecessary, instead skewing the actual cost of nuclear energy.[46]

Supporters view the Price-Anderson Act as a necessary element to the continued success of the nuclear energy industry. As costs to cover total damages from a severe nuclear disaster are virtually unrecoverable, no single utility could afford the coverage to keep working if the liability caps were lifted, making them uninsurable on their own. As NRC noted, "many nuclear suppliers express the view that without Price-Anderson coverage, they would not participate in the nuclear industry."[47] While the current facilities would still be covered, as they became older and outdated, the risks would become greater. Without the ability to form newer there would be fewer and fewer contributors to the pool, and thus less remedy in the case of a disaster.[48]

Thus, the debate in Congress continues. Most recently, the expiration date of the Act was extended to Dec. 31, 2006,[49] as part of President Bush's 2004 National Energy Plan. Last session, a bill in the House of Representatives (H.R. 6) was in committee to extend the Act until 2017, while a companion bill in the Senate was in committee which would eliminate the expiration date.

VII. Other Considerations

A. Institute for Nuclear Power Operations

One result of the Three Mile Island nuclear accident in the late 1970s was that the nuclear power plant owners, with support from the Electric Power Research Institute, created the Institute for Nuclear Power Operations (INPO). Two of the objectives of the organization are to increase the reliability and safety of all aspects of nuclear power plant ownership and operation. Today, INPO staff conducts regular on-site inspections of all nuclear power plants in the U.S. on a regular basis. These inspections include examination of the physical plant, the operating procedures and records, the training of personnel, and the management of the facility. INPO works hand-in-hand with federal Nuclear Regulatory Commission and its staff.

The results of the inspections are used by the plant owners to upgrade their operations, and by the federal regulators to ensure safety of operation. They are also reviewed by the insurance companies that provide various types of insurance coverage for some or all of the nuclear facility. The INPO activities are voluntary on the part of the owners and the inspections and subsequent corrective actions of the owners have resulted in significant increases in operating safety, plant reliability, and plant performance.

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[46] Nuclear Bailout: Price-Anderson Act (Dec. 12, 2004) *at* http:www.greenscissors.org/energy/price-anderson.htm.
[47] U.S. Nuclear Regulatory Commission, *The Price-Anderson Act - Crossing the Bridge to the Next Century: A Report to Congress*, October 1998.
[48] *See* Note 2.
[49] National Defense Authorization Act for Fiscal Year 2005, Pub. L. No. 108-375 § 3141.

This voluntary industry approach, with the federal regulators looking over their shoulders, has worked. Another nuclear accident is unacceptable to the industry and probably would result in a phased shut-down of the operating plants. So the stakes are very high. This voluntary industry action has worked for the past 20+ years.

VIII. Policy Issues

A. Regulation

i. Reserve Funds

In a few states, regulated utilities are allowed to create and contribute to storm reserve funds to collect recovery expenses before natural disasters. However, this approach is very limited as public utility commissions generally view such funds as an inappropriate collection of ratepayer's money. There must be a clear and definable need demonstrated by the utility for the State Public Utility Commission to entertain such proposals. In the State of Florida, regulated utilities are allowed to maintain and contribute to such funds because of the frequent occurrence of tropical storms and hurricanes. During the hurricane season of 2004, four hurricanes came ashore in Florida and did considerable damage to electric utility facilities. The three major regulated electric utilities all had accumulated Storm Reserve Funds: Florida Power and Light - $345 million, Progress Energy Florida - $45 million, and Tampa Electric - $43 million.[50] For all three utilities, the repair and restoration costs for the 2004 season have exceeded their Storm Reserve Funds and have petitioned the Florida PUC for rate increases to cover the excess costs.

In other states, utilities are not allowed to collect such large funds, usually only a few million dollars (less than 10 by one informal estimate) are allowed. In most states, these funds are not allowed at all. Both the PUCs and the IRS do not look with favor on such funds.

ii. Security Mitigation

A number of state regulatory commissions PUCs have allowed various security expenditures by utilities to become part of rate procedures for the purpose of reimbursement of those expenses. The various PUCs have not been consistent in their actions so the National Association of Regulatory Utility Commissioners (NARUC) funded a study of the various approaches being used throughout the U.S. The resulting report, *Model State Protocols for Critical Infrastructure Protection Cost Recovery* (July 2004 – Ver. 1) (include prior reference) documents the wide range of procedures for the regulated utilities to recover security costs. In a large number of states, no utility has requested action; in a number expedited procedures have been put in place; and in a few, normal rate change procedures are being used. However, in all situations, the end point is a full rate hearing approach. In discussions with a few utilities, they indicate that their PUCs have preferred that security-related requests be filed in a rate case , so

[50] Johnson, Bradley W. (2005) *After the Disaster: Utility Restoration Cost Recovery.* Washington, D.C.: Edison Electric Institute.

they, and other utilities in their state, have not initiated such a process. Other utilities such as Oklahoma Gas & Electric Company, have utilized expedited procedures put in place by the Oklahoma PUC and already have had rate adjustments to cover approved security investments.

iii. Insurance vs. Security Mitigation

In one state,[51] utility personnel have found that the PUC is not open to expenditures on security mitigation efforts that will reduce system and facility vulnerabilities but will allow various insurance products to be purchased by the utility to defray repair and restoration costs after a disaster. This is true even though the utility can demonstrate that the mitigation measures are lower in cost than the insurance premiums and that they reduce vulnerabilities. Purchasing insurance instruments is considered a common business expense and thus allowed. Vulnerability mitigation expenditures are more unknown and thus are scrutinized more closely and sometimes not allowed.

iv. U.S. Department of Agriculture - Rural Utility Service

The Department of Agriculture's Rural Utility Service (RUS) has taken a stronger tact regarding rural cooperative's physical and cyber security. For those cooperatives "…with an approved RUS electric program loan/grant as of October 12, 2004 shall perform an initial VRA [Vulnerability and Risk Assessment] of its electric system no later than July 12, 2005." This is in accordance with 7CFR Part 1730 Electric System Emergency Restoration Plan (Final Rule published in the Federal Register, October 12, 2004). Each individual loan-holding cooperative must certify by July 12, 2005 that a VRA has been conducted.

B. Non-regulatory – The Evolution of Industry Security Guidelines & Standards

i. Electric Utility Industry

There are no required standards that address security design, installation, operation, or maintenance for the electric utility (non-nuclear) portion of the Energy Infrastructure; this includes physical and cyber security. The closest to required standards are the various standards and guidelines that have been and are being established by the North American Electric Reliability Council (NERC); these cover various operations of its members – utilities, merchant plant owners, industry associations, etc. However, at this time, these are all voluntary.

> "NERC's mission is to ensure that the bulk electric system in North America is reliable, adequate and secure. Since its formation in 1968, NERC has operated successfully as a voluntary organization, relying on reciprocity, peer pressure and the mutual self-interest of all those involved. Through this voluntary approach, NERC has helped to make the North American bulk electric system the most reliable system in the world" (NERC Web page accessed 12/14/04).

[51] Confidential telephone interview conducted by CIPP NETL Project team, January, 2005.

NERC has set standards for a range of electric system reliability, operations, and planning activities and these have been successful up until the mid-1990s when industry deregulation and restructuring began. Because of the large number of new organizations involved in the generation, transmission, distribution, marketing, and energy brokering, these voluntary standards are proving insufficient to maintain the reliability of the nation's electric infrastructure.

No standard audit on enforcement mechanisms is in place with regard to security standards in this sector. In 1998, at the request of the U.S. Secretary of Energy, NERC began working with the U. S. Department of Energy to develop a program for "information sharing, cooperation, and coordination between private industry and the government." One result of this is the possible evolution of NERC from a voluntary organization to a legal compliance organization. The legislation to enable this change to occur is included in most of the National Energy bills presently under consideration by Congress.

Since the events of 9/11, the entire electric utility industry has been reexamining its approach to security. In May 2002, NERC issued a report, *The Electricity Sector Response to the Critical Infrastructure Protection Challenge*, which describes "… the general approach to action implicit in the plans and programs industry members, NERC, and its regional councils take to assure service." This document provides the general framework for NERC and its members to increase the level of reliability and security at individual firms and the electricity sector as a whole. This report includes discussions of:

A. Identification of Critical Services and Assets
B. Vulnerability Assessments
C. Risk Assessments and Management
D. Recovery and Restoration
E. Monitoring and Updating
F. Information Sharing, Education, and Awareness

Since early 2002, NERC has been developing new security procedures for its members. These major security procedures relate directly to electric utilities and are briefly summarized below:

Security Guidelines for the Electricity Sector (Ver. 1.0 – 06/14/02): This guideline covers vulnerability and risk assessments, threat response, emergency plans, continuity of business plans, communications, physical security, cyber security, employment background screening, and protecting potentially sensitive information.

Urgent Action Standard 1200 – Cyber Security: This cyber standard was adopted by the NERC Board of Trustees on August 13, 2003, just one day before the major northeast blackout. This standard was adopted for one year, with provisions for extensions, while approval by American National Standards Institute (ANSI) as a permanent standard. Members must be able to demonstrate "full adherence" to the standard by 2005; however, it is still voluntary for the NERC members. It was developed and adopted not only to significantly enhance the level of security of member's cyber systems but also to avoid having FERC or other federal agencies impose mandatory standards on the electric utility industry. The standard is considered a good first step by the industry. A list of the areas covered by the standard is given below. NERC states it is not a "how to" document but needs to be used with detailed security documents, such as the National Institute of Standards and Technology's (NIST) "Risk Management Guide for Information Technology Systems" and the ISO 17799 Standard.

NERC Urgent Action Standard 1200

Standard/Title	Standard/Title
1201 Cyber Security Policy	1209 Monitoring Electronic Access
1202 Critical Cyber Assets	1210 Information Protection
1203 Electronic Security Perimeter	1211 Training
1204 Electronic Access Controls	1212 Systems Management
1205 Physical Security Perimeter	1213 Test Procedures
1206 Physical Access Control	1214 Electronic Incident Response Actions
1207 Personnel	1215 Physical Incident Response Actions
1208 Monitoring Physical Access	1216 Recovery Plans

Standard 1300 – Cyber Security (Ver. 1.0 – 09/15/04): This standard, which will replace Urgent Action Standard 1200, is currently in its third draft as part of the NERC certification and adoption process. Standard 1300 includes SCADA, communications, and data transmission areas and is expected to become effective on November 1, 2005. The standard is applicable to entities that perform as: Reliability Authority, Balancing Authority, Interchange Authority, Transmission Service Provider, Transmission Owner, Transmission Operator, Generator Owner, Generator Operator, and Load-Serving Entity. A list of the areas covered by the standard is given below.

NERC Standard 1300 – Cyber Security

Standard/Title	Standard/Title
1301 Security Management Controls	1305 Physical Security
1302 Critical Cyber Assets	1306 Systems Security Management
1303 Personnel & Training	1307 Incident Response Management
1304 Electronic Security	1308 Recovery Plans

In discussions with personnel from a number of electric utilities with responsibilities in security areas, most indicate that although these NERC guidelines and standards are presently voluntary, their organizations are implementing them as if they were required.[52] In these discussions, the utility personnel fully expect that at some point in the near future, these will become required, either through federal legislation or as a condition of continued membership in NERC.

Presently, NERC operates the Electric System – Information Sharing and Analysis Center (ES-ISAC), the ES-ISAC "…serves the Electricity Sector by facilitating communications between electric sector participants, federal government and other critical infrastructure industries. It is the job of the ES-ISAC to promptly disseminate threat indications, analyses, and warnings, together with interpretations, to assist electricity sector participants take protective actions."

On February 10, 2004, the NERC Board of Trustees established a Critical Infrastructure Protection Committee to "…advance the physical and cyber security of the critical electricity infrastructure of North America."[53] Note: NERC has both Canadian and Mexican utility members. The role of the Committee is to act as an expert advisory panel for NERC activities, the ES-ISAC, and all levels of government.

C. Other Roles for Government: The TRIA Backstop for Private Product Offerings

The reinsurance market has responded to the needs of insurers in conjunction with the federal backstop coverage provided by The Terrorism Risk Insurance Act (TRIA). TRIA is scheduled to sunset in December 2005. If TRIA were allowed to expire, there would be a large gap to fill. Insurer terrorism exposure would increase nine-fold increase above its TRIA deductible.

Catastrophe modelers have refined their terrorism models since introduction of the models and are better able to help insurers assess exposure both at individual locations and for aggregations of exposures. However, many aspects of terrorism risks remain unknown, and may not be quantifiable in the foreseeable future. Although progress has been made on quantifying the potential costs of defined types of attacks on locations with specified characteristics, the probabilities associated with occurrence of an attack remain subject to a strong degree of guesswork.[54]

As of March 2005, insurers have begun a strong push for Congress to renew TRIA. [55]

D. Reliability: How Much Is Enough?

Electric utility systems have traditionally been designed and operated to provide electric service to all customers with similar reliability and quality: "universal service." Any specific customer, however, may experience reliability and quality levels above or below

[52] In truth, it is at present not possible to find a "report card" of the level of compliance with NERC standards, either by individual company or by sector.
[53] See http://www.nerc.com/~filez/cip.html.
[54]American Academy of Actuaries Extreme Events Committee. (2004, May). *P/C Terrorism Insurance Coverage: Where Do We Go Post-Terrorism Risk Insurance Act?*
[55] see www.insureagainstterrorism.org, a website of the Coalition to Insure Against Terrorism

the average system values; this depends upon where the customer is located and how they are served.

The reliability of a utility system is a direct function of BOTH how it was designed and how it is operated. Reliability can be considered from the perspective of a single piece of equipment, a major system (e.g., transmission), and the entire utility. It can also be considered on a regional level – a number of utilities - and the national level, with all 3,100+ utilities. Electric utility systems are normally designed to continue operating and not interrupt load to any customer if the largest system contingency goes out; a contingency may be, for example, the largest generating unit on the system or the largest transmission substation importing power from outside the system.

A number of statistical- and deterministic-based approaches are used to evaluate the reliability of a utility system. These approaches model the electric system, utilize historical outage and maintenance data for major facilities, and provide an estimated reliability level such that an average customer would be without service for not more than, for example, "one day in ten years." The target levels for service reliability and quality selected by the utilities and reviewed by state public utility commissions PUCs, have a direct effect on the design of the system, the selection of specific equipment to be installed, and cost. The system envisioned by the planners and installed by the engineers is usually not the system configuration that is operated every day. Equipment failures, scheduled maintenance, availability and cost of external power, and different load patterns all impact the system configuration that is in operation at any point in time.

Utilities can provide higher levels of reliability and quality to customers requiring such service, but at a premium rate, higher up-front costs, or both. An example of this is where a data center is served by two independent feeders directly from the utility's transmission lines. Over 90 percent of the service outages occur on a utility's distribution so providing a large commercial or industrial customer's service directly from the transmission system provides a much higher level of reliability. When such a data center measures its revenue in $ millions per minute, the price of higher reliability electric service to reduce the probability of outages is very cost-effective.

Major blackouts are very costly to citizens, business, and utilities. The cost of increasing the level of reliability at the feeder, substation, or utility level can be very expensive. Thus, critical questions must be asked before rushing to require significant investments in response to quickly passed legislation or regulations: Is it necessary and cost-effective to increase the reliability for all customers? Should the present levels of reliability be accepted and charge those customers needing higher reliability higher rates?[56]

The electric utility industry has not made the investments necessary to increase the capabilities of the systems to continue with the present level of reliability – especially in the areas of transmission. It is recognized that this lag in investment has occurred for a variety of reasons. For example, the regulatory or legislative path is not clear to organization -

[56] This question is explored to some extent in , by Fumagalli, Elena, et al (2004, Aug). IEEE TRANSACTIONS ON POWER SYSTEMS, Volume 19 No. 3, p. 1286.

E. Interdependencies

In discussions with both insurance and utility personnel, when the topic of infrastructure interdependency is raised, it is admitted that this is a significant unknown factor. At present, there is no detailed methodology or commercial software that either the insurance companies or their policyholders can use to identify interdependencies and determine levels of risk and/or vulnerability.[57]

From the electric utility perspective, it is presently common practice for a firm conducting a risk and/or vulnerability assessment to examine only the equipment and facilities that it owns and to not "look over the fence" to its upstream suppliers. Personnel from critical upstream suppliers (e.g., fuel, cooling water, communications etc.) do not participate in the assessment. For the most part, infrastructure interdependencies are covered only in a cursory manner in existing assessment methodologies.

From the insurance company perspective, infrastructure interdependency is a growing "unknown that they are having difficulty getting their arms around." Without validated procedures, tools, or software models to guide people making an assessment, it is extremely difficult to identify all the upstream dependencies that a utility's facility depends upon. This is very difficult at the first (direct) level and almost impossible at the second or third level.

Sandia National Laboratories' Critical Infrastructure Group has done some modeling of interdependencies, but their approach requires extensive data collection and the complete modeling of both infrastructures (e.g., electric and natural gas) for their model to work. And it requires the Lab's significant computing capability to run the software. Therefore, the present feasibility of using such a tool for a large number of urban areas is not high. Other, more usable methodologies and tools are needed.

IX. Conclusion

This paper has set forth the findings of a DoE-sponsored research team that investigated the relationship between the Electricity sector and Insurance during the period August 2004 through February 2005. The paper describes the role Electricity plays in the nation's economy, and the new threats to the Electricity sector's infrastructure that have become apparent pursuant to homeland threats such as the events of September 11, 2001.

As we seek to offer additional protection to the Critical Infrastructures of the nation – of which Electricity is one – the role of insurance bears reexamination. It seems possible that insurance could be used to hedge risk to infrastructures by promoting security standards and creating infrastructure-related products.

[57] The Institute of Public Utilities at Michigan State University recently completed an overview paper on interdependencies for NARUC. It can be found at http://www.naruc.org/associations/1773/files/Interdependencies%20%28%232%29%2Epdf

The findings of this research team, however, indicate no current nexus between the Electricity sector's desired insurance coverage and an infrastructure-oriented offering. In addition, there appear to be no sample products offered that would inform a case study of infrastructure-related offerings. In short, there has been no movement to date in the direction of increasing infrastructure protection through insurance.

These findings raise follow-on questions about the relationship between the Electricity and Insurance sectors. Why have there been no infrastructure-protection offerings from the Insurance sector? Given the obvious risk to U.S. infrastructure in the current threat environment, why has the Electricity sector remained content with standard business-operations policy options? Most importantly, is it possible to bring these two sectors together for the good of the nation without compromising the interests that each has in a sound and profitable business?

The research team and DoE have convened a workshop for June 22 and 23, 2005, to explore these and related questions. The outcomes of that workshop, and observations related thereto, will form the basis of a follow-on paper exploring the possibilities for Electricity and Insurance moving forward.