Consortium for Electric Reliability Technology Solutions

Grid of the Future White Paper on

Accommodating Uncertainty in Planning and Operations

Prepared for the
Transmission Reliability Program
Office of Power Technologies
Assistant Secretary for Energy Efficiency and Renewable Energy
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Preface

In 1999, the Department of Energy (DOE) tasked the Consortium for Electric Reliability Technology Solutions (CERTS) to prepare a series of white papers on federal RD&D needs to maintain or enhance the reliability of the U.S. electric power system under the emerging competitive electricity market structure.[1] In so doing, the white papers build upon earlier DOE-sponsored technical reviews that had been prepared prior to the Federal Energy Regulatory Commission (FERC) orders 888 and 889.[2]

The six white papers represent the final step prior to the preparation of a multi-year research plan for DOE's Transmission Reliability program. The preparation of the white papers has benefited from substantial electricity industry review and input, culminating with a DOE/CERTS workshop in the fall of 1999 where drafts of the white papers were presented by the CERTS authors, and discussed with industry stakeholders.[3] Taken together, the white papers are intended to lay a broad foundation for an inclusive program of federal RD&D that extends – appropriately so -- beyond the scope of the Transmission Reliability program.

With these completed white papers, DOE working in close conjunction with industry stakeholders will begin preparation a multi-year research plan for the Transmission Reliability program that is both supportive of and consistent with the needs of this critical industry in transition.

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[1] The CERTS DOE research performers are Edison Technology Solutions (ETS), Lawrence Berkeley National Laboratory (LBNL), Oak Ridge National Laboratory (ORNL), Pacific Northwest National Laboratory (PNNL), Power Systems Engineering Research Center (PSERC) and Sandia National Laboratories (SNL). PSERC is an National Science Foundation Industry/University Collaborative Research Center that currently includes Cornell University, University of California at Berkeley, University of Illinois at Urbana-Champaign, University of Wisconsin-Madison, and Washington State University.

[2] See, for example, "Workshop on Real-Time Control and Operation of Electric Power Systems," edited by D. Rizy, W. Myers, L. Eilts, and C. Clemans. CONF-9111173. Oak Ridge National Laboratory. July, 1992.

[3] "Workshop on Electric Transmission Reliability," prepared by Sentech, Inc. U.S. Department of Energy. December, 1999.

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List of Acronyms

ATC	Available Transfer Capability
CBM	Capacity Benefit Margin
CEA	Canadian Electricity Association
CERTS	Consortium for Electric Reliability Technology Solutions
DISCO	Distribution Company
DOE	Department of Energy
EPRI	Electric Power Research Institute
EUE	Expected Unserved Energy
FCITC	First Contingency Incremental Transfer Capability
FEMA	Federal Energy Management Agency
FERC	Federal Energy Regulatory Commission
GADS	Generation Availability Data System
GENCO	Generating Company
LOLP	Loss-of-load Probability
NERC	North American Reliability Council
OASIS	Open Access Same-time Information System
RTO	Regional Transmission Organization
SCADA	Supervisory Control and Data Acquisition
SEAB	The Secretary of Energy's Advisory Board
TRANSO	Transmission Company
TRM	Transmission Reliability Margin
TTC	Total Transfer Capability
WAMS	Wide Area Measurement System
WSCC	Western Systems Coordinating Council

Executive Summary

Restructuring in the electric power industry raises a fundamental question: how will the sweeping transformations caused by restructuring affect the reliability of the nation's electricity grid? In the past, utilities traditionally provided a complete, or bundled, set of power-related services and maintained reliability under an obligation to serve in exchange for market privileges such as a monopolistic franchise. In the future, many of these power-providing institutions will evolve into new business entities, fragment into independent organizations, or cease to exist as new participants enter the emerging, competitive environment. Reliable electric power, according to many analysts of the coming changes, will become a graded commodity for sale at variable levels of quality and cost. This report discusses uncertainties that are not captured in the planning process used by utilities in a regulated environment and it also discusses emerging uncertainties as the electric industry undergoes restructuring. In latter sections, the report identifies technologies/methodologies that can be developed and employed to accommodate or manage these uncertainties to ensure reliable electric power. We briefly discuss market-supplied solutions to planning, operations, and reliability issues.

The term "uncertainty" is used here in a mathematical sense: uncertainty is the difference between a measured, estimated, or calculated value and the true value that is sought. Uncertainty includes errors in observation and calculation. In this instance, the sources of uncertainty are varied and include transmission capacity, generation availability, load requirements, market forces, fuel prices, and forces of nature such as extreme weather. They may affect planning and operations in the short-term or long-term. Some, like weather, can affect planning at both time-scales.

Planning and operations are temporal categories into which activities or functions are traditionally classified. Actions that influence or control power flows in real time or in the immediate future typically fall into operations, and actions that influence or plan the flow of power at a future time, on the order of days or longer, typically fall into planning. Yet a fundamental change is underway in the electric power industry with respect to the these processes, which now must successfully manage the higher levels of uncertainty accompanying restructuring. In addition, the information gathering and processing tools now widely used cannot be readily extended to deal with new requirements. For these reasons, a shift in the information and decision-making framework, or paradigm, of the electric power industry will be required in the future. At the heart of this shift are changes in how information is collected, the type of information needed, how it is used in decision processes, and the time spans between data collection, decision, and action. One of the driving motivations for this shift will be the reliability of electric power.

Interconnected power systems are highly complex mechanisms, and control of these systems becomes increasingly difficult with restructuring. Factors such as the entry of new participants, increases in cross-regional power exchanges, and new types and numbers of distributed generating resources and loads all act to complicate system planning and operations. Deterministic methods and tools that are now used for operations will not be adequate to accommodate restructuring changes and the uncertainties that accompany them. Probabilistic methods and tools provide a means to cope with increasing complexity and information flow, to allow statistical data to predict future system performance, and to deal with existing and new uncertainties.

A recent report by the Secretary of Energy's Advisory Board (SEAB)[4] on the reliability of the electric power system called for new technologies to accommodate uncertainty in planning and operations and recommended four areas in which they can be used:

1. Characterization and probabilistic models for uncertainties in power system operating conditions, such as better measures of errors in system stability assessments or planning models.

2. Probabilistic models, tools, and methodologies for collective examination of contingencies that are now considered individually, such as models that can accommodate correlated failures of system elements.

3. Cost models for use in quantifying the overall impact of contingencies and ranking them accordingly, such as models that can predict outage economic impacts.

4. Risk management tools, based upon the above probabilistic models of contingencies and their costs, that optimize use of the electrical system while maintaining requisite levels of reliability, such as risk-based assessments that can be used in an operations-planning environment.

In addition to these, this report recommends:

1. Quantifying system health (and well being) through numerical risk indices, such as the loss of load expectation or expected energy not supplied. This can be categorized by defining indices of the system's well being, which will provide a framework to evaluate overall system performance as well as information to system planners and operators.

2. Rapid collection, analysis and distribution of data at major load delivery points as well as comprehensive monitoring of component performance to assess the causes of system reliability events.

Recent reliability events briefly summarized here make it clear that a loss of system control can lead to power outages of enormous social and economic consequences. System operators and planners must have better technologies at their disposal to cope with the many changes and growing uncertainties of the changing electric power environment.

The following discussion includes a list of needs for technologies that can be used to better manage the sources of uncertainties in planning and operations for power systems. We include large-scale projects that would extend over several years as well as short-term developments that can yield useful tools to aid power system operators through the present restructuring transition

[4] "Maintaining Reliability in a Competitive U.S. Electricity Industry," final report of the Task Force on Electric System Reliability to the U.S. Secretary of Energy's Advisory Board September 29, 1998.

period. Transfers of existing technology from Department of Energy (DOE) labs, along with collaborations among commercial vendors, research institutions, utilities and power providers, and DOE labs can accelerate development of needed tools, models, and methods for accommodating uncertainty. Federal funding is needed to successfully integrate these tools to improve and maintain the reliability of the nation’s electric power system.

1. Introduction

1.1 Background

The interconnected systems that supply electric power to North America form one of the most complex mechanisms in operation today. More than 400 million people in the U.S., Canada, and Mexico depend on a vast network of generators, transmission lines, and distribution to provide reliable power. Reliable electric power is requisite to the services and systems that support our society, such as communications, transportation, finance, medical, and emergency services.

This complex system and the organizations that own, operate, and regulate its components are undergoing profound changes as the electric power industry restructures. The task of keeping power flowing reliably across the networks of North America, a daunting challenge in prior times when utilities honored an obligation to serve, will be complicated by new market forces, many new participants, and new rules regarding electric power generation, transmission, distribution, trading, and sales.

A recent report by the Secretary of Energy's Advisory Board (SEAB), "Maintaining Reliability in a Competitive U.S. Electricity Industry," discusses the challenges to electric power reliability in the face of these changes.[1] The specific recommendations of the SEAB report regarding new methods, tools, and models that are needed to accommodate uncertainty in planning and operations of electric power systems are among the topics of this paper. The term "accommodate" as used in the present context refers to the ability of some methods, tools, and models to take uncertainty into consideration or otherwise incorporate measures of uncertainty into results. A closely related topic, methods and tools that can be used to reduce uncertainty in planning and operations, specifically the use of real-time monitoring and reliability issues, will be discussed in two other CERTS papers, "Real-Time Monitoring and Control of Power Systems" and "Review of Recent Reliability Issues and System Events."

High levels of uncertainty or large uncertainties that cannot be accommodated or managed in operations and planning ultimately lead to reduction in power reliability, which leads in turn to outages. Obviously, the practical implications of power system reliability reach beyond theoretical studies and computer models as recent outages demonstrate.

The importance of a reliable electric power system is dramatically underscored by power outages that affect large populations; major U.S. outages are discussed in detail as part of a separate CERTS white paper, " Review of Recent Reliability Issues and System Events." Some of these outages merit reiteration here. The November 1965 blackout in the Northeastern U.S. left some 30 million people without power. The ensuing focus on reliability helped drive the formation of the North American Electric Reliability Council (NERC). Later, the July 1977 outage in New York City left about 9 million people without electric power for up to 25 hours, totaling an

[1]U.S. Secretary of Energy Advisory Board (SEAB) Report, "Maintaining Reliability in a Competitive U.S. Electricity Industry: Final Report of the Task Force on Electric System Reliability," September 29, 1998, U.S. Department of Energy. Appendix E of this report, "Technical Issues in Transmission System Reliability" (May 1999), includes a Section 3 which addresses "Planning Tools for Increased Uncertainty - Treating Uncertainty in Reliability Assessment."

estimated $55 million in direct costs, while indirect costs, including lost revenues to small businesses and new capital equipment expenditures, were over $290 million. A series of outages in some of the utilities in the Western States Coordinating Council (WSCC) during July and August of 1996 emphasized the need for better simulation models, planning tools, and measurement systems.

When a heat-related outage occurred in New York City in July 1999, U.S. Secretary of Energy Bill Richardson announced a six-point plan to improve electric power reliability and "reduce the threat of blackouts during severe weather." His plan issues a call to:

1. Convene a Northeast regional power summit.

2. Investigate power outages.

3. Speed new Federal standards for more efficient air conditioners.

4. Study the nation's electricity capacity and the ability to meet future needs.

5. Cut Federal consumption during emergencies.

6. Develop new generation and transmission technologies.

These reliability events, along with a change in the operational paradigm as analyzed in the SEAB report, are motivating factors for this research. In the following sections, we:

- discuss sources of uncertainty in planning and operations and how these relate to reliability;
- describe some of the tools, methods, and models needed to accommodate this uncertainty, including those tools recommended by the SEAB report; and
- list areas in which continued or new research, development, and demonstration are needed.

To lay a common groundwork for these discussions, the following section defines terms that are fundamental to these topics.

1.2 Definitions

Assessment of power system reliability is generally divided into two aspects: system adequacy and system security. Assessment of system adequacy deals with steady-state operation and planning of the power system, i.e., it gauges the ability of a power system to supply and deliver electric energy to satisfy customer demand. System security assessment gauges the ability of a power system to respond to sudden changes and/or disturbances such as the loss of a generator or transmission line. There are two aspects to power system security. The first deals with the ability of the system to withstand internal failures and sudden natural disturbances, including network overload, voltage problems, and instability problems. The second aspect deals with the ability of the system to avoid external interference, attack, or coordinated physical assault on the system. Traditionally system planners dealt only with the first aspect of security, i.e., problems arising from system operation, random failures of system equipment and natural disturbances. It must be emphasized that the term “security” as used in this paper refers mainly to this (first) aspect.

Figure 1 shows how reliability, security, and adequacy are related.

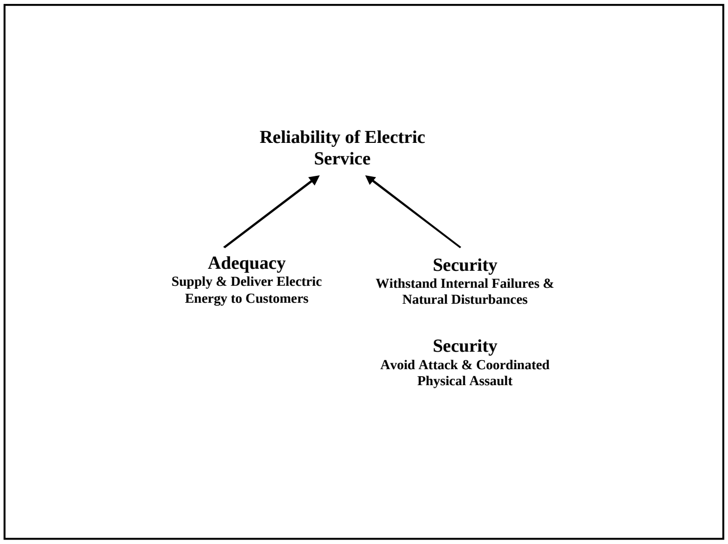

Figure 1: Reliability is tied to both adequacy and security.

This report uses the definitions for reliability, adequacy, and security given in the NERC Glossary of Terms, August 1996:

> **Reliability –** The degree of performance of the elements of the bulk electric system that results in electricity being delivered to customers within accepted standards and in the amount desired. Reliability may be measured by the frequency, duration, and magnitude of adverse effects on the electric supply. Reliability of the electric system can be addressed by considering two basic and functional aspects of the electric system -- adequacy and security.
>
> **Adequacy –** The ability of the electric system to supply the aggregate electrical demand and energy requirements of customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.
>
> **Security –** The ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements.

Some common terms used within this report, in the context of power systems and probabilistic methods, have specific or narrow definitions compared to their common usages. These are listed below:

Operations – Actions that influence or control power flows in real time or in the immediate future; here, assumed to be on the order of one day.
Planning – Actions that influence the flow of power at a future time, on the order of days or longer.

Stochastic, stochastic processes – Although this term is sometimes used as a synonym for "random," it is used in this paper to refer to a set of random variables ordered in a given sequence, often with time as an indexing parameter.

Hazard – An event which, if it occurs, leads to a dangerous state or a system failure. In other words, it is an undesirable event, the severity of which can be ranked relative to other hazards.

Risk – A measure of both probability and consequence or degree of hazard for some event.

Uncertainty –Mathematically, uncertainty is the difference between a measured, estimated, or calculated value and the true value that is sought. Uncertainty includes errors in observation and calculation. Uncertainty may be associated with demographic and economic factors (inherent to forecasting methods), and environmental, social and political factors.

2. Sources of Uncertainty in Planning and Operations

2.1 Reliability, Operations, and Planning

The main purpose of a power system is to satisfy the demands of customer loads reliably and economically. Figure 2 shows the relationship in electric power systems of system planning, system operation, data collection, and system monitoring to power reliability as seen by customers or consumers and how they support each other. Unresolved system planning problems or constraints will eventually become system operation problems and constraints and will therefore affect power system reliability. For example, not incorporating uncertainties in system planning may lead to a reliance on operations to reduce risk and maintain reliability.

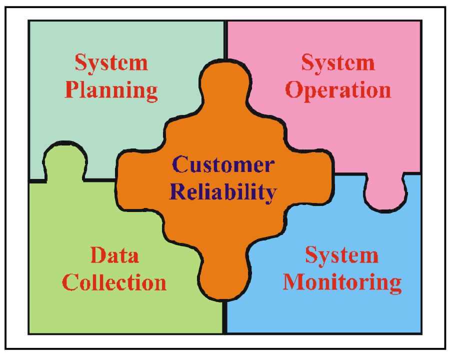

Figure 2: Graphic Depiction of the Interrelationship among Power System Reliability (as seen by Customers), System Planning, Operations Data Collection, and System Monitoring.

This paper only briefly mentions data collection and system monitoring issues, yet these topics have a strong bearing on reliability. Both are treated in another CERTS paper, "Real-Time Monitoring and Control of Power Systems."

Many of the factors that influence operation of a power system are beyond the control of the operator, who cannot completely determine or know them. Load switching, for example, occurs in accordance with customers' needs and may appear to have random characteristics to the operator when resolved to fine levels, except in the rare case of demand management systems that allow operators to control loads. As another example, the capacity of transmission lines depends on environmental factors such as wind and ambient temperature, and these influencing factors are usually not known sufficiently by the operator to allow for real-time planning or forecasting. Uncertainty in demand, transmission and generation parameters, equipment failures, extreme weather, and other environmental factors invariably create some measure of uncertainty in operation and planning. In general, the degree of uncertainty increases significantly from a shorter time frame in system operation to a longer time frame in system planning. For example, based on the current conditions, system operators have more confidence in forecasting the customer load demand for the next hour than forecasting the load next month.

2.2 Uncertainty, Risk, and System Positioning

The risks associated with any particular level of uncertainty in system operation depend, in part, on the relative proximity of that system to adequacy limits or to stability limits that are determined or estimated during system planning. Several possible scenarios exist for future power systems and how they might be positioned relative to these limits.

One plausible scenario for future power systems is that in the emerging, competitive, and restructured environment for U.S. electric power, they will be operated at points closer to their operational and stability limits. There are several motivations for (and potential difficulties as a result of) operating power systems closer to their limits. First, restructured and competitive energy markets will depend on power exchanges across many transmission entities and regions, and these regions may have conflicting regulatory and market structures. Next, the profit imperatives in a competitive energy market will drive generation and transmission asset utilization, and shortages of new generation and transmission capacity are anticipated in light of projected load growth. Finally, transmission bottlenecks caused by increased cross-regional power exchanges are anticipated by many analysts.

Another possible future scenario for power systems operations is that concerns regarding liability and risk will push operating points away from more efficient regimes that would require improved control technologies and tighter assets management. That is, the “low-tech” option may offer relatively low-risk operation perhaps at the expense of system economy and efficiency.

The following section examines sources of uncertainty and discusses how that uncertainty may bear on the factors described in further detail in the following section. Some factors, such as weather or available transfer capacity, have an impact on operations, short-term planning, and long-range planning.

2.3 Sources of Uncertainty

2.3.1 Traditional Sources of Uncertainty.

Table 1 summarizes sources of uncertainty that have traditionally existed in the electric power industry. This table includes factors that contribute uncertainty in both the short-term and long-term.

Source of Uncertainty	Contributing or Causal Factors
Generation Availability	Unplanned outages, equipment failures, protective relaying, economic factors including fuel prices and market prices, reserve availability, reactive power requirements, climactic variables such as precipitation and hydro-power availability, environmental regulations including emissions restrictions.

Transmission Capacity	Line ratings, weather-related factors including ambient temperature, wind and ice storms, geophysical events including lightning and earthquakes, geomagnetic storms, unplanned outages and equipment failures, trans-regional power exchanges.
Load	Weather-related factors including temperature and precipitation, economic factors including economic growth, new types of electronically-controlled loads, variations in load power factors.
Distribution System	Equipment failures, unplanned outages, economic factors including distribution classes, load shedding policies, weather-related factors such as ambient temperature.

Table 1: Sources of Uncertainty and Contributing Factors in the Traditionally Structured Electric Power Industry.

2.3.2 New Sources of Uncertainty.

2.3.2.1 Transmission capacity and available transfer capability.

Available Transfer Capability (ATC) measures the available transmission capacity of a specific line, path, or piece of electrical equipment associated with a transmission network. In accordance with U.S. Federal Energy Regulatory Commission (FERC) Orders 888 and 889, the ATC is posted on the WEB-accessible Open Access Same-time Information System (OASIS) to allow buyers and sellers a publicly available means to determine if sufficient transmission capability exists between generators and consumers in a proposed power transaction. The ATC is calculated by transmission system operators and is an essential factor in determining the contract path for a power exchange.

The ATC is determined by subtracting existing transmission commitments and transmission capabilities required for reliability considerations from the total transmission capability. Specifically, the ATC is defined by NERC[2] as "the Total Transfer Capability (TTC) less the Transmission Reliability Margin (TRM), less the sum of existing transmission commitments (which includes retail customer service) and the Capacity Benefit Margin (CBM)." The TTC is a measure of the transmission limits (or maximum transfer capability) of the interconnected transmission given that all pre-defined system reliability constraints are satisfied. The TRM is the "amount of transmission transfer capability necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions." CBM is the transmission transfer capability reserved by load serving entities to ensure access to generation from interconnected system to meet generation reliability requirements. As of now, there is no universal method among utilities in determining ATC, TRM and CBM.

[2] NERC Available Transfer Capability Working Group, "Available Transfer Capability Definitions and Determination – A framework for determining available transfer capabilities of the interconnected transmission networks for a commercially viable electricity market," June, 1996.

Uncertainty and error enter the ATC calculation in several ways. At least five categories of uncertainties were identified in the Regional Councils' submissions to NERC.[3] These include load forecast uncertainties, generation dispatch uncertainties, parallel path (or "loop") flows, "normal operating margin," and calculation/modeling inaccuracies. Although each of these uncertainties affect the ATC calculations, the degree of influence generally increases as the time horizon on uncertainty increases.

Although FERC, EPRI, and others offer guidelines for ATC calculations, transmission system operators may elect to use their own unique methods to account for factors such as measurement error and load growth. ATC calculations can be based on historical data and posted many weeks in advance of a transaction. For example, one transmission system operator adds approximately 3% to the ATC calculation to account for load growth and 3% to allow for error in measurements. These factors had been determined from historical trends and operating experiences.

Physical uncertainties also enter into ATC calculations. The existence of parallel transmission paths can cause a large difference between transmission on a contract path and the actual electron flow. Transmission system operators may not be aware of a particular power exchange yet may find that transmission capability on their system is reduced because of an exchange between others. Errors in monitoring and measurement equipment are a factor in the ATC, yet uncertainty in those errors is not typically reported.

The sources of uncertainty in ATC calculations can be summarized as follows[4]:

1. Lack of direct measurement of transmission limits. The First Contingency Incremental Transfer Capability (FCITC) is the most common method used in determining the ATC. FCITC cannot be measured directly, and good estimates of FCITC requires skill and experience on the part of system engineers.

2. The definition of ATC. Requires subjective interpretation since it reflects planning and operating practices and procedures. Each transmission line owner/operator has latitude in how they calculate the ATC.

3. Transmission capability. This is stochastic, i.e., it varies in time with random variables of operating conditions, and ATC errors may vary randomly rather than systematically.

4. Transfer capability. This can also be influenced by the wheeling of power, parallel flows due to economic transaction.

5. Unplanned outages of lines or equipment associated with the contract path or an adjacent path.

6. Outages or limitations on generation in the proximity of the contract path that has an impact on the TTC.

[3] KEMA Consulting, "Assessment of CBM and TRM," EPRI TR-110766, May 1998.
[4] H.M. Merrill, "Exploiting the Random Nature of Transmission Capacity," *Public Utilities Fortnightly*, Sept., 1998.

7. Equipment temperatures or loss of cooling equipment.

2.3.2.2 New sources of generation.

Since 1989, more than 50% of new generating capacity in the U.S. has been from non-traditional sources[5] including renewable sources such as wind and photovoltaics, fuel cells, and gas micro-turbines. These sources will connect and disconnect from the network with greater randomness than traditionally scheduled, utility-controlled generation sources. Information regarding performance details and device models, particularly dynamic models, are lacking.

2.3.2.3 New markets, market instruments, business structures, and market forces resulting from restructuring.

Competitive or free electric power markets can, paradoxically, cause or exacerbate reliability problems or, alternatively, provide solutions for reliability issues. The New England and California energy markets are adjusting market rules based on their recent experience. The role of markets in this past summer's price spikes in the Midwest and the bearing of these prices spikes on reliability are still being studied and debated. Some analysts argue that, in the long run, the market will provide free-market-based reliability solutions and market-based instruments will provide alternatives to traditional planning. Other experienced analysts disagree with this view and stress the continued need for long and short-term planning similar to that provided by the vertically-integrated utilities.

Changes in the energy market and business structures resulting from industry restructuring will affect system operations and planning. Some of the uncertainty and related problems resulting from changes underway or proposed include:

1. Uncertainties in daily operation arising from open market trading of power. Availability of generation depends on the market condition where intermediate or peaking generation from one region (and generation units started) can be obtained by another region provided the price is right and transmission constraints allow.

2. Uncertainties in taking operating risks (degrading system security) as a result of optimizing profits by a variety of players.

3. Uncertainties in maintaining a long-term stability (lack of central coordination) under the new environment. Each unbundled entity, e.g., Disco, Transco, Genco, will be responsible for satisfying its customers.

4. Problems arising from dealing with non-firm transmission as a service.

[5] R. Stevenson and D. Ray, "Transformation in the Electric Utility Industry," in W. Sichel and D. Alexander, eds., *Networks, Infrastructure, and the New Task for Regulation*," University of Michigan Press, 1999.

5. Management of congestion, particularly congestion arising from fast-changing power flows or exchanges between distant areas.

6. Problems arising from market anomalies, thin or under-performing markets, immature markets, and changes in market structures.

2.3.2.4 Changes in system planning and resource planning resulting from restructuring.

In a regulated environment, the utility invested financially in the resources needed to serve its customers, with the assurance of a reasonable return on its investment. It was guaranteed a monopoly status in its service area to protect its investment, and in exchange, the utility was obliged to serve all existing and future customers on a non-discriminatory basis at tariff rates. Today, with the changing nature of regulation and the imminent demise of the monopoly status, such planning has virtually been abandoned. Resource planning as a function has practically ceased to exist, and the status of transmission planning may best be characterized as being in limbo. In the absence of regulation, these assurances no longer exist, but it is premature to assume that the obligation to serve has ceased to exist. The unbundling in the utility industry has left the customer-service sector with an obligation to serve at least for the foreseeable future. The bulk generation/transmission system, however, may not be subject to the obligation to serve. Therefore, there is an unwillingness to invest in new plant and equipment where the risk is high, because there is no longer assured return on investment and customers may migrate to other electricity suppliers when given a choice. This unwillingness translates into a large measure of uncertainty regarding long-term planning and availability of future generation and transmission assets.

For new generation capacity, the prevailing attitude is that the market will provide. For the near-term in most regions, the absence in investment in new generation resources is not a critical issue because of existing over-capacity. However, transmission capacity is a different issue because it will remain a monopoly. The issue is the establishment of appropriate economic signals for the market to invest in the upkeep and upgrade of the transmission system. One of the rationales for the proposed Regional Transmission Organizations (RTOs) is to set up a mechanism for joint planning of transmission for large geographic areas.

The lack of coordinated planning and timely system expansion during the transition from a regulated monopoly to an unregulated competitive market will introduce another uncertainty, which can best be labeled as planning uncertainty.

3. Current Approaches to Accommodating Uncertainty and their Limitations

3.1 Time-Scales in Planning and Operations

System operators must collect information and make decisions based on that information in time-scales ranging from milliseconds to years. Short-term horizons for operations and planning range over minutes to days, while long-term horizons span months to years. Table 2 shows the range in time-scales for planning and operations functions.

Time	Normal Operations	Abnormal Operations
Milliseconds	Dynamics monitoring, Automatic control functions.	System oscillations, Protective relaying.
Seconds	SCADA monitoring, Control of generators, Changes in loads, Change spinning reserve.	Detect and evaluate system disturbances.
Minutes	Start/Stop interruptible loads, Offline simulations, Spot purchases.	Implement corrective action (e.g., restore lines), Load shedding, System breakups.
Hours	Load scheduling, Generator startups.	System reconstitution, Failures analyses.
Days	Generation scheduling.	Repair weather-related damages, Failures analyses.
Months	Scheduled maintenance, Simulations.	Facility repairs , Failures analyses, Repair weather-related damages.
Years	Facilities planning, Load forecasting, Regulatory changes. Facilities construction.	Litigation, Facilities modifications, Overbuilding of system assets.

Table 2. Time Scales for Various Functions in Electric Power Systems Operations and Planning.

In the restructured environment of the electric power industry, many of the functions listed in Table 2 will be handled among several organizations rather than performed within one vertically integrated utility, creating new challenges to system operations and requiring new resources, tools, methods, and techniques to accommodate uncertainty in diverse sources of information.

3.2 Tools, Methods, and Techniques Currently Used or in Development for System Planning and Operations

Utilities and other power providers have traditionally used deterministic tools that could not accommodate uncertainty or estimate risk for operations. Probabilistic tools have been widely adopted for system planning purposes, and recent research has focused on development of risk-based system security assessments that could be used to assess limits in real time.

In the past few decades, much research has been conducted in the area of probabilistic system adequacy assessment. As a result, probabilistic reliability techniques have been widely used in generation resource planning. Because the industry is moving into a competitive environment, probabilistic reliability assessment is gaining momentum in transmission planning because of its ability to incorporate various planning and operating uncertainties in the analysis.

Existing power system models that use probabilistic methods to perform system studies include EPRI's Transmission Reliability Evaluation of Large Scale System (TRELSS) and Composite Reliability Assessment by Monte-Carlo (CREAM); GE's Multi-Area Reliability Simulation (MARS) and Market Assessment and Portfolio Strategies (MAPS); Power Technologies' Local Area Reliability Assessment (LARA) and Multi-Area Reliability AnaLysis (MAREL). Other probabilistic-based tools from vendors outside the U.S. include Powertech Lab's COMposite RELiability (COMREL) and STAtion RELiability (STAREL) developed by the University of Saskatchewan, Canada, and BC Hydro's Montecarlo Evaluation of COmposite system REliability (MECORE), also developed at the University of Saskatchewan. There are various generation reliability programs and composite reliability programs being used outside of the North America. Researchers in UK, France, Italy, and Brazil etc., are actively developing and implementing probabilistic techniques in power system planning and operating.

Since the 80's, researchers have been investigating the area of probabilistic power system security assessment. Due to the lack of fast computing facilities and fast algorithms to detect instability, these efforts have been primarily implemented in the university environment and locally for small regions by planning engineers. The advances in fast computing equipment and the development of many fast algorithms to detect the instability of the power system in the past ten years, together with the need to include the various uncertainties in system security evaluation have enabled researchers to seriously investigate this area. As a result, various major researches on probabilistic power system security assessment are currently being conducted around the world. Some of the major contributors are R. Billinton (Canada), V. Vittal & J. McCalley (U.S.), A.M. Leite da Silva & J.C. Mello (Brazil) and Electricité de France (EdF, utility in France).

These activities demonstrated that there is a real need for risk-based power system security evaluation. However, like its predecessor, power system adequacy evaluation, this will not and cannot be achieved overnight. It took almost twenty years for the probabilistic power system adequacy evaluation techniques to become mature enough for use in power system planning. Even now, there are different approaches and emphases in applying the probabilistic adequacy evaluation techniques. The same will be true for security evaluation, which is an even more complicated endeavor. Fundamental research and concept implementation are needed. With recent advances in computers and the increased demand for such tools in a deregulated, competitive environment, the pace of development in power system security evaluation will probably be much faster than before.

3.3 Limitations in Current System Planning and Operation Assessment Methodologies and Tools

3.3.1 Limitations in Current System Planning and Operation Assessment Methodologies and Tools.

3.3.1.1 Inaccuracies and errors in planning models and simulations.

A lack of realism in system models and significant differences between model-predicted behavior and actual system behavior was an important factor in the August 10, 1996, breakup of the Western States Coordinating Council (WSCC) electricity system. Real-time security assessments are, as yet, not possible with current models and computing resources. Off-line simulation studies are labor intensive and often do not match actual operating conditions, especially for unusual system configurations like those in the WSCC during August of 1996. Key requirements needed for improved measures of the uncertainty in simulations include better data sets for generation plant parameters as well as probabilistic representations of system elements such as transmission assets.

The accuracy of power system analysis also has a significant impact on operational guidelines for power systems, operational planning, and design. For example, accurate stability analysis is necessary to allow for more precise calculations of a power system's operation limits. The accuracy of stability analysis, however, depends largely on the validity of the system models employed in describing power system dynamic behaviors (here, system model refers to the model structure and its associated parameter values). Effective system models are essential for simulating complex power system behaviors. For example, inaccurate load models can lead to a power system being operated in modes that result in actual collapse or separation of the system.[6]

Manufacturers develop parameter values for the model structures of generators and their control systems by using an off-line approach. In most cases, however, the parameter values provided are fixed and do not reflect the actual system operating conditions and the effect of nonlinear interaction between the generator (or control system) and the other parts of the system. For instance, when an excitation system is put into service, its model parameter values tend to drift due to (1) changes in system operating conditions, (2) the nonlinear interaction between the excitation system and the rest of the power system, and (3) the degree of saturation and equipment aging, etc. In addition, the parameter values of excitation systems provided by manufacturers are typically derived from tests at the plant, before the excitation system is actually put into service. These tests are often performed by measuring the response of each individual component of the device separately; those individual components are then combined to yield an overall system model. Although adjustments can be made during commissioning, accurate parameter values may not be generally available once the device is installed within the power system.

[6] H.D. Chiang, private communication, August 1999.

In the past, the issue of how to accurately model power system components such as synchronous generators, excitation systems, and loads has received a great deal of attention from the power industry. Standard generator and excitation model structures have been developed, and standard load model structures for stability analysis are emerging as well. A remaining issue is how to derive accurate parameter values for these models, because uncertainties in these parameter values translate to uncertainties in modeling products.

3.3.1.2 Inadequate treatment of multiple contingencies and correlated failures.

Industry currently plans for loss of any single element (N-1 contingencies) or, less frequently, for the loss of multiple elements (N-X). Operating transmission systems within N-1 security constraints has several important implications. First, these systems tend to be inefficient because economic optimums are disallowed by the requirement to operate through any single failure. Second, these contingencies are typically deterministic and do not include risk, that is, the probability and consequence of possible outage configurations. Finally, deterministic system operation and planning based on N-1 security doesn't provide the operator with critical information following a failure nor during an outage: 1) the likelihood of another system element failing, 2) the likelihood of the system remaining stable after the first contingency, 3) system components that are most stressed following any particular failure, and 4) the areas that are most vulnerable to system instability.

Due to the complexity of modeling and the large amount of computation required, current probabilistic approaches for both power system adequacy and security are not entirely probabilistic, but usually take a hybrid approach by combining both probabilistic and deterministic models. For example, risk-based security studies calculate the likelihood of a system becoming unstable and its consequence under various contingencies. However, the contingencies chosen or screened are still deterministic in nature, i.e., the loss of a set of pre-defined element or components under a certain loading condition. The parameters that determine whether a system will remain stable, such as the loading at the time of contingency, protective-gears clearing time, or the contingency itself, are stochastic in nature and should be modeled as such.

Current techniques and available tools are also limited in their ability to analyze correlated failures. For example, a severe storm may damage more than one transmission line at a particular time. The ability to analyze common mode outages or simultaneous damage to many elements of a network that is widespread geographically has not been fully developed.

3.3.1.3 Lack of probabilistic reliability criteria, lack of tools that translate long-range planning criteria into operational planning and implementation.

Most probabilistic long-term reliability planning is generally not applicable in short-term operation and implementation. Tools or techniques that can help to develop operational strategies by complementing short-term planning and implementation with long-term planning based on probabilistic approach would be needed.

3.3.1.4 Uncertainties in power system equivalents and dynamic reductions.

Electric power systems are non-linear and complex. Power system static and dynamic equivalents are used by system planners and operators in conducting system simulations. These equivalents are intended to represent parts of the system external to the main area of interest in the power system. There are errors and uncertainties in deriving these equivalents.

Dynamic reductions are reduced-order models that are intended to preserve the required dynamic characteristics of the system under study. Dynamic reductions are used in system simulations to reduce computational efforts. Dynamic reduction is based on the aggregation of 'coherent groups' of generators. A group of generators is coherent if the relative differences between their rotor angles remain constant following a disturbance. Frequently, there are errors and uncertainties in performing dynamic reductions.

3.3.1.5 Inadequate maintenance planning.

Maintenance planning becomes a greater challenge with restructuring, and it will need to be coordinated with a greater number of external organizations in the restructured environment. Maintenance scheduling was a factor in the recent Midwestern price spikes.

3.3.1.6 Inadequate real-time dynamic transmission rating tools and models.

Deterministic methods for transmission line ratings are typically performed in a planning environment and result in ratings for transmission assets that are below economic optimums. Some work has been done to develop probabilistic line ratings,[7] but results have not been widely applied in the U.S. Tools to permit real-time dynamic rating of transmission lines are needed.

3.3.1.7 Inadequate load planning, long-term and short term.

Load forecasts reflect both long-and short-term uncertainties. They are typically based on historical data and include other factors such as short-term economic changes and weather information. As the electric power industry moves toward an environment of competition and customer choice, utilities can no longer count on long-term customers. With the utility no longer having the obligation to serve customers (who tend to be primarily interested in lower rates and increased reliability), are free to choose their suppliers.

A national survey in the U.S. indicated that 69% of customers would switch electric suppliers for just a 2% reduction in price; 81% will switch for a 5% reduction; 90% for a 10% reduction; and 92% for a 15% reduction.[8] Customers also stated that reliability is very important, and yet an increase in reliability does not guarantee improved loyalty; but a decrease in reliability could be disastrous.

One source of uncertainty affecting planning and operations is the level of reliability that is acceptable to both customers and utilities. Distribution utilities face uncertainties in developing

[7] M.J. Tunstall, "Probabilistic Transmission Line Book Ratings Employed by National Grid, U.K.", IEEE Power Engineering Society meeting, July 1998.
[8] This survey is discussed in R. Billinton et al., "Reliability Issues in Today's Electric Power Utility Environment," *IEEE Transactions on Power Systems*, vol. 12, no. 4, Nov. 1997, pp. 1708-1714.

buying and selling strategies to protect their investment and their customers, and current techniques do not treat these uncertainties well.

3.3.2 Limitations on Data Collection and System Monitoring.

3.3.2.1 Inadequate system performance data, both static and dynamic.

System dynamic performance data are typically sparse, and dynamic performance measurement experiments are difficult and expensive. In addition, monitoring systems that can measure system dynamic performance with resolutions adequate for studies of dynamics are not widely applied in the United States. One such system, the Wide Area Measurement System (WAMS), provided key information regarding the August 1996 breakup of the WSCC system.

Indices to measure system performance are in an early stage of development. In fact, little work has been done to date to correlate system performance indices such as power quality indices with model products.

3.3.2.2 Inadequate component performance data.

Probabilistic techniques for reliability studies and risk assessments require component performance data sets that accurately reflect actual performances over a statistically meaningful range of time and application. Large, detailed data sets for power system components that reflect long histories for large systems are rare.

The Canadian Electricity Association (CEA) has a very comprehensive system of collecting and publishing system component outage data on generation, transmission and distribution systems, as well as on system performance information at major delivery points. Unfortunately, the submission of this information to CEA is voluntary. It may be more difficult in the future to obtain acceptable data as Gencos, Trancos and Discos move into a competitive environment in which they consider such data a part of their competitive edge. Without comprehensive data, the capability to predict reliability and maintain a reasonable planning activity will be limited.

3.3.3 Control Design and Hardware.

3.3.3.1 Uncertainties in System Controls.

What types of control schemes will be effective in the restructured environment? Controller performance issues, operational robustness, and unanticipated automatic control responses have been brought into question following the 1996 WSCC breakups.[9] Factors that contribute to controller behavior in dynamic environments include:

- Large and abrupt changes in system topology and/or operating conditions,
- Operating conditions substantially different from those considered in planning studies,

[9] J.F. Hauer and C.W. Taylor, "Information, Reliability, and Control in the New Power System," 1998 American Control Conference, June 24-26, Philadelphia, PA.

- Planning models that are inaccurate with respect to small-signal dynamics or load characteristics,
- Poor observations of actual system behavior.

3.4 Deterministic Versus Probabilistic Techniques to Accommodate Uncertainty

Deterministic approaches usually consider the worst-case scenario. The result of the analysis is most often qualitative and therefore difficult to use in a decision-making process. Deterministic methods also impose a hard limit on system operations. As a result, systems are often designed, planned or operated to withstand severe problems that have a low probability of occurrence.

Probabilistic techniques and approaches consider factors that may affect the performance of the system and provide a quantified risk assessment using performance indices such as probability and frequency of occurrence of an unacceptable event, duration and the severity of unacceptable events etc. These performance indices are sensitive to factors that affect the reliability of the system. Quantified descriptions of the system performance, together with other relevant factors such as environment impact, social and economic benefits etc., can then be entered into the decision-making process.

Deterministic methods alone cannot adequately address the various transmission challenges such as the available transfer capability (ATC), long transmission and related voltage/reactive and security (stability) problems, transmission project ranking, transmission congestion alleviation, uncertainty of weather, environmental constraints and the competitive environment, uncertainty of customer load demand, uncertainty of equipment failure and operation.

The following table compares limitations of deterministic and probabilistic approaches in planning.[10]

	Deterministic	**Probabilistic**
Contingency Selection	Typically a few probable and extreme contingencies	More exhaustive list of contingencies
Contingency probabilities	Implicit, based on judgement	Explicit, but generally based on inadequate data
Load levels	Typically seasonal peaks and selected off-peak loads	Multiple levels
Analysis	Steady state/dynamics	Steady state at present (1990)
Reliability	None	Various indices calculated
Criteria for decisions	Well established	Need a cautious approach to select criteria due to limitations in data contingency probabilities and the models

Table 3. Limitations of Deterministic and Probabilistic Approaches in Planning.

[10] From M. Bhavaraju, "Application of Contingency Evaluation Techniques to Practical Systems," in *Reliability Assessment of Composite Generation and Transmission Systems*, IEEE 90EH0311-1-PWR, 1990.

3.5 An Example of Uncertainty for the Establishment of Voltage Stability Criteria

Table 4 lists uncertainties that should be considered before establishing voltage stability criteria in a system. This list is included to illustrate the volume and diversity of information needed by system planners. As described in previous sections, the volume of information required for planners and operators is increasing with restructuring. This increase of data required is driving the need for a new paradigm for information processing and decision making.

1.	Customer real and reactive power demand greater or less than forecasted
2.	Approximations in studies (Planning and Operations)
3.	Outages not routinely studied on the member system
4.	Outages not routinely studied on neighboring systems
5.	Unit trips following major disturbances
6.	Lower voltage line trips following major disturbances
7.	Variations on neighboring system dispatch
8.	Large and variable reactive exchange with neighboring systems
9.	More restrictive reactive power constraints on neighboring system generators than planned
10.	Variations in load characteristics, especially in load power factors
11.	Risk of next major event during a 30-minute adjustment period
12.	Not being able to readjust adequately to get back to a secure state
13.	Increases in major path flows following major contingencies due to various factors such as on-system undervoltage load shedding
14.	On-system reactive resources not responding
15.	Excitation limiters responding prematurely
16.	Possible Remedial Action Scheme failure
17.	Prior outages of system facilities
18.	More restrictive reactive power constraints on internal generators than planned.

Table 4: Considerations of Uncertainties for Establishment of the Voltage Stability Criteria.[11]

Processing of the information in Table 4 and the use of this information in decision processes has traditionally depended on the knowledge of experienced system engineers. This knowledge base is undergoing a transformation as technical staff within utilities is reduced to improve investment returns. In many cases, corporate technical knowledge is disappearing. At the same time, the amount of information that needs to be collected, processed and incorporated into operational and planning criteria is increasing. Some of the drivers for this increase in information include:

- Increased numbers and types of generating sources
- Greater volumes of system monitoring information
- More design complexity, automatic control issues
- Greater volumes of information for market exchanges

[11] A. Abed, "Voltage Stability Criteria," in IEEE Tutorial Text on Voltage Stability, IEEE PES Summer Meeting, July 1998.

4. Accommodating Uncertainty in the Grid of the Future

4.1 New Information and Greater Volumes of Information in the Grid of the Future: A New Paradigm for Decision Making

A fundamental change is underway in the electric power industry with respect to planning and operations processes. Planning and operations must successfully manage higher levels of uncertainty that accompany restructuring, and the information gathering and processing tools that are now widely used cannot be readily extended or scaled to deal with new requirements. A shift in the information and decision-making framework, or paradigm, of the electric power industry will be required in the future. At the heart of this shift are changes in how information is collected, the type of information needed, how it is used in decision processes, and the time spans between data collection, decision, and action. One of the driving motivations for this shift will be electric power reliability.

Interconnected power systems are highly complex mechanisms, and control of these systems becomes increasingly difficult with restructuring. Factors such as the entry of new participants, increases in cross-regional power exchanges, and new types and numbers of distributed generating resources and loads all act to complicate system planning and operations. Deterministic methods and tools that are now used for operations will not be adequate to accommodate restructuring changes and the uncertainties that accompany them. Probabilistic methods and tools, risk-assessment techniques, and other new methods in development can provide better means to cope with increasing complexity and information flow, to allow statistical data to predict future system performance, and to deal with existing and new uncertainties. However, it does not appear realistic to assume that new models or tools can solve the emerging problems of uncertainty and system control. A new framework, or paradigm, for decision making within the electric power industry is required.

Decision-making processes in the electric power industry, like the generating systems it incorporates, have dynamic and non-linear characteristics. It does not appear likely that the limited set of deterministic and probabilistic and risk-assessment tools, the lack of real-time system assessments, the limited reliability information, and the pace of development and acceptance of new techniques and tools are sufficient to cope with the greater volumes of information and faster pace of decision making that will be essential to the new electric power environment.

One possible form for this new paradigm is a shift from a concentration on optimization of possible solutions to a concentration on decisions and minimizing the regret felt by a decision maker *after* verifying that the decisions he has made were not optimal, given that in fact something has occurred.[12] By shifting from a use of probabilistic choice to use of risk analysis as the basis of decision, system configurations that represent better compromises with less risk can be selected and hedging or other risk aversion strategies can be employed. A risk analysis or risk assessment paradigm, some researchers argue, more closely matches the way people

[12] V. Miranda and L. M. Proenca, "Why *Risk Analysis* Outperforms *Probabilistic Choice* as the Effective Decision Support Paradigm for Power System Planning," *IEEE Trans. Power Systems*, vol. 13, no. 2, pp. 643-648, May 1998.

intuitively make decisions. Whether or not the risk analysis method provides a paradigm that will work effectively in the electric power industry, a new decision-making paradigm will be required in the future, and risk analysis techniques are one possible alternative to the present paradigm.

Another possible shift in decision making processed involves new market instruments. Some analysts argue that, in the long run, the market will provide free-market-based reliability solutions and market-based instruments will provide alternatives to traditional planning activities. Other experienced analysts disagree with this view and stress the continued need for better decision-making processes, including long- and short-term planning.

One example of a new market instrument related to power system reliability is the "weather bonds" being offered or planned by Enron Corporation and Koch Industries. The returns on these three-year bonds are tied to differences between historical average temperatures and officially reported temperatures in the operating regions of these power providers. If temperatures deviate from a predetermined range about the historical averages, returns on these bonds drop. If temperatures for the next three years stay within expected ranges, investors will realize a relatively high rate of return. These bonds afford a measure of insurance to the power providers against financial losses caused by extreme temperatures.

4.2 Techniques, Models, Resources and Tools Required for a New Decision-Making Paradigm

Important to consider are the new technologies required to support this new decision-making framework, and the way in which a transition from the current decision-making paradigm to a new one will occur. In general, the following technologies, tools, or information will be needed:

- New criteria for decisions,
- The means to translate long-term, long-range planning criteria based on probabilities into operational planning and implementation,
- New information sources, including real-time monitoring information, probabilistic component information, and historical or statistical information for large systems,
- Decision-making techniques that accommodate uncertain or missing information,
- New ways of processing and presenting large volumes of information, including human-factors consideration, new computing techniques, and data visualization technologies,
- Identification and connection to specialised knowledge bases.

4.3 Recommendations of the SEAB Report

The Secretary of Energy's Advisory Board, Task Force on Electric System Reliability, recently recommended the development of tools to help reduce and accommodate uncertainty in planning and operations. Section 3, "Planning Tools for Increased Uncertainty -- Treating Uncertainty in Reliability Assessment," from Appendix E of the SEAB Report concludes with the following recommendation:

> "The Task Force recommends that appropriate entities, such as the DOE, in cooperation with the electric power industry, develop risk-based tools for reliability assessment and transmission investment planning."

Section 3 also states that two parallel efforts will be required to provide reliable and economical electricity in a more complex environment:

1. Reduce uncertainty, in all its forms, through better and more timely information.

2. Use planning tools that directly accommodate such uncertainty as it still remains.

Specifically, the SEAB Report recommends the following new technologies:

1. Mathematical tools that can examine power system signals for warnings of unstable behavior, in real time and very reliably.

2. Mathematical criteria, tools, and procedures for reducing and/or characterizing errors in power system models. This can lead to on-line parameter modeling, and load and generator modeling, which can improve the stored model used in reliability and stability analyses.

2. Characterization and probabilistic models for uncertainties in power system operating conditions.

4. Probabilistic models, tools, and methodologies for collective examination of contingencies that are now considered individually. Probabilistic reliability assessments use statistically based methods to simulate combinations of single or multiple faults or equipment outages. The numbers of possible combinations of faults or outages are large for typical bulk power systems.

5. Cost models for use in quantifying the overall impact of contingencies and ranking them accordingly (It is essential that these models be realistic and suitable for use as standards for planning and operation of the overall grid). Traditional reliability indices, like LOLP or EUE, can be used initially.

6. Risk management tools, based upon the above probabilistic models of contingencies and their costs, that optimize use of the electrical system while maintaining requisite levels of reliability.

Items 1 and 2 above apply to monitoring and measurement systems and the problem of reducing uncertainty; items 3 through 6 deal with the problem of accommodating uncertainty, the focus of this report.

4.4.1 Challenges in RD&D.

In a restructured operating environment, better techniques, models, resources, and tools are needed to assess system dynamics, control systems, and plan for contingencies. Power providers and utilities will need new models and tools to handle the greater volumes of information that are resulting from industry restructuring. Some of the technical and computational challenges in creating these new tools, techniques, and methods are:

1. The number of system elements and possible configurations or contingency states that need to be considered is very large. Currently available computing hardware is not adequate to process these large sets of possible configurations and produce results that are useful in real-time or near-real time. Restructuring will create more possible configurations, combinations and contingencies. Fast screening techniques are needed to screen and rank those contingencies that are contributing to the risk of the system.

2. Rare events or unusual configurations with high-consequence impacts must be considered. The summer 1996 WSCC breakups resulted from unusual system conditions that had not been considered in planning studies and also demonstrated a need for faster assessments of system dynamics.

3. The interactions among system elements will necessitate more detailed mathematical models for technical planning. The need was demonstrated in the 1996 WSCC outage when engineers could not reproduce the same sequence of events using their existing model.

4. Power system complexity is increasing. New types of resources, e.g., fuel cells, solar cells, wind turbines, etc., will also require new models for systems analyses.

4.4.2 Challenges Of Application.

The successful application of newly developed tools, methods, techniques, and resources in power system applications requires active participation by power providers and the power industry. Information needed for development of these tools, models, and methods must flow two ways: developers within the public sector need to understand real needs within the industry and what solutions already exist; industrial partners need to understand the possible benefits as well as the cost of implementation.

In the past, it has proved difficult to validate and test new tools and models in power system application, and this lack of validation contributes to reluctance on the part of the industrial partners to accept new technologies. The advantages of probabilistic methods and tools will also be difficult to convey to those power system decision-makers accustomed to using cost-based or deterministic tools. However, many traditional views within the power industry are falling with the sweeping force of restructuring and the present offers a unique opportunity for acceptance of new technologies and tools.

4.4.3 Broad Research Areas.

Broad-based research areas include fundamental research topics that are outlined in Section 4.3, including:

- New information-processing techniques including parallel-processing methods,
- New data-presentation and visualization techniques including 3-D data visualization,
- New risk-assessment methods,
- Knowledge and distributed intelligence techniques, including new methods to provide rapid access to knowledge and information and new methods to analyze complex systems.

4.4.4 Some Specific Tools, Techniques, Resources, and Models that are Needed for the Grid Of the Future.

4.4.4.1 Characterization and probabilistic models for uncertainties in power system operating conditions (a recommendation from the SEAB Report).

Tools that are currently being planned, including some developed in DOE national labs, could help quantify the uncertainty of simulated system behavior. One effort currently uses improved sampling methods for reliability and uncertainty analysis to test model behavior and measure uncertainty in modeling products. The speed enhancements offered by these new algorithms make it possible to greatly accelerate testing when compared with traditional methods, such as Monte Carlo analysis. Another effort is the development of a set of tools for probabilistic power system security assessment. These tools incorporate various uncertainties that actually affect the stability performance of the system and provide a number of useful indices such as probability of instability, etc. These tools will provide the ability to plan, operate and design a power system for robust and safe operation.

Power system planning is traditionally based on a single point estimate, usually the average, of the parameters under consideration. In a new competitive environment, it will be necessary to consider a range of these parameters, from a single point estimate to the recognition of extreme cases. Probabilistic tools such as stochastic optimization, Monte-Carlo and sequential system simulation, fuzzy models, expert systems and neural networks will be required in order to estimate and accommodate uncertainties.

4.4.4.2 Probabilistic models, tools, and methodologies for collective examination of contingencies that are now considered individually (a recommendation from the SEAB Report).

4.4.4.2.1 Multiple contingencies.

Although existing models currently support multiple-contingency analyses, it is difficult to select the set of contingencies that corresponds to possible configurations. Performing random analyses of all possible configurations for multiple contingencies will, in general, not be useful and will be computationally expensive. Currently multiple contingencies are handled in a deterministic manner, i.e., each contingency represents a particular system state such as a threephase fault on a particular line under the system peak load condition. The selection or rejection of this contingency is based on the risk it incurs to the system, such as the likelihood of occurrence and the consequence of having such event. However, the occurrence of different types of fault, the occurrence of a fault on a particular line, the system load condition at various load points, the protection-gear clearing time etc., are stochastic in nature. Probabilistic methods are therefore required to aggregate or select those contingencies that are likely to occur or identify those that result in high levels of risk. Tools in development at one DOE lab will offer the ability to screen and rank contingencies.

4.4.4.2.2 Composite reliability evaluation.

In the new competitive environment, the availability of generation may be driven to a greater extent by the market, and conventional generation planning will become less common. With increasing transmission constraints and decreasing transmission availability due to increases in economic transactions, composite generation and transmission planning will become the primary planning focus.

Probabilistic composite generation and evaluation of transmission system reliability provides the means to evaluate the benefits of providing system support, such as ancillary services. The results can be used in calculating compensation for these ancillary services. Composite reliability evaluation eliminates the traditional "N-1" criterion that imposes hard limits on system operation. It also allows the inclusion of risk in reliability evaluation.

Probabilistic composite reliability evaluation techniques provide composite performance indices that are useful in decision making based on the level of acceptable risk.

4.4.4.2.3 Probabilistic risk-based adequacy and security operation and planning.

Competition provides strong motivation for system planners and operators to reevaluate the traditional deterministic approach used in system security. Risk-based system adequacy planning using composite reliability evaluation techniques has been gaining momentum in the past few years; however, research is also being done in the area of probabilistic security evaluation of power system. Recent publications include work on various aspects of risk-based power system security evaluation conducted by Billinton et al. (Canada), Vittal & McCalley et al. (U.S.), Leite da Silva & J.C. Mello et al. (Brazil) and Electricité de France (EdF), etc.

System operation also introduces additional uncertainties, such as uncertainty in short-term transmission flows, which are usually driven by the remote economic transaction. Competitive electric energy systems create incentives for a variety of players to take operating risks in order to maximize their profits, providing a motivation to develop a risk-based approach to security assessment. A risk-based approach will provide an equitable balance in the tradeoff between cost and security, resulting in substantial savings and will help prevent haphazard risk taking by operators. However, this risk-based approach will require a faster method for computing security limits, including probability and consequences when compared to existing methods.

Competition will inevitably bring new and possibly large numbers of players into the market, making coordination and control, including security assessment, more difficult and uncertain.

Whether this problem is going to be addressed by creating Independent System Operators (ISO) or some other coordinated effort, the question of balancing security and profit will be approached in the same manner, i.e., it must provide economic incentives for the participants (both suppliers and consumers) to include in their decision-making regarding system security levels.

Another need that may arise in the future is combining system adequacy and system security into one single framework. One of the supporting arguments is that outage data, which we are currently collecting in the field, includes both system adequacy and security outages. Power system adequacy assessment assumes that the system will always reach a new stable equilibrium state after the outage has been isolated. This is not always the case, because the system may become unstable due to cascading effects associated with the disturbances. Currently, security assessments, mostly transient stability evaluations, are generally conducted using deterministic methods, although sometimes they are combined with probabilistic adequacy studies. Recent development in risk-based security assessment will allow an integration of both probabilistic power system adequacy and security studies under one single framework.

Risk-based assessment techniques provide useful information on the probability and consequence evaluation of events, cost consequences, justification of performance criteria, limit identification and risk allocation, etc. This tool will also help to develop operational strategies by complementing short-term planning with long-term planning based on the cost/benefit approach.

4.4.4.3 Cost models for use in quantifying the overall impact of contingencies and ranking them accordingly (a recommendation from the SEAB Report).

A recent survey found no existing models that could estimate the cost of large, widespread electric power outages before the outage event and with sufficient resolution to be useful in quantifying contingencies. Most existing models are ex-post (run after the event) and have large granularity, i.e., coarse geographic resolution.

A model developed by the Federal Emergency Management Agency (FEMA) illustrates relatively high-resolution consequences analysis, and is reported to have cost about $9 million to develop. The FEMA model “HAZUS” projects earthquake damage on a county-scale for the entire U.S. “HAZUS” used census data, input-output modeling techniques, and geographic information system (GIS) databases to project earthquake damage in selected regions.

A significant challenge in developing cost models for evaluating electric power contingencies will be acquiring and compiling necessary data in useable form. Currently available data from U.S. Federal or state sources are not sufficiently detailed for these cost models.

Over the past 20 years, significant efforts have been made in Canada, principally at the University of Saskatchewan, to measure the cost of power outages for different types of customers. The method is based on actual customer surveys (with appropriate number of samples) in each customer category using techniques that have basically been accepted by many planning engineers and are gradually gaining acceptance at the management levels. One obstacle to acceptance of this method of estimating outage costs by many utility managers is a lack of familiarity with statistics-based techniques. However, many utilities have been using this information in ranking and screening their projects, and they are successful in doing so. Utilities and researchers have conducted cost of service interruption surveys all over the world in UK, North America and Asia. This survey and resulting data are valid only with normal power outages, not large, widespread blackouts such as the 1996 WSCC outages.

4.4.4.4 Risk management tools, based upon the above probabilistic models of contingencies and their costs, that optimize use of the electrical system while maintaining requisite levels of reliability (a recommendation from the SEAB Report).

A useful approach in balancing and optimizing the reliability cost and its worth is the value-based approach, the main purpose of which is to maximize the reliability benefits by minimizing the cost to provide an increase in reliability performance. The worth of reliability uses the cost of interruption concept to convert the reliability benefit (e.g., EUE) into monetary quantities. The reliability cost and worth approach tries to balance both the cost of outages and the cost to improve the system reliability. This approach can be applied to any functional zones, i.e., generation, transmission, generation/transmission, station, distribution, etc.
Probabilistic techniques have been used in the financial investment market successfully for quite some time, and various techniques such as the Schole-Black Equation, Value-at-Risk and other statistics tools have been successfully applied to the commodity market.

In an open, competitive environment, energy is simply treated as another kind of commodity. The probabilistic techniques currently used in the investment market, together with the probabilistic techniques to predict the performance of an overall system will provide valuable tools for the distribution utilities to develop hedging strategy for buying and selling of power in order to protect the customers and the utility from the price fluctuation in the power market.

The development of an acceptable hedging policy based on the system conditions is vital, as was demonstrated in the Alberta outage in October 1998. Those who developed and applied a proper hedging strategy were not significantly affected, whereas those who had not done so suffered the most by paying as much as $1000/MWhr (only because of a price cap; it could be higher if no cap existed) at one time.

Value-based approach can be used in developing strategy for rare events such as the 1996 WSCC blackout. Events like this cannot be evaluated based on likelihood of occurrence or on the consequence alone. The balance of cost and benefit approach will help to develop defense plans using controls, maintenance, and the testing of these equipments, as well as to develop proper restorative plan including supplies, crews, and procedures after the event.

4.4.4.5 System health (well-being) evaluation.

A question system planners and operators often ask is how much margin, whether it is security or adequacy margin, does the system have under a certain system condition. This information is particularly important because system margins are shrinking due to increases in economic transactions. A single numerical risk index, such as the loss of load expectation or expected energy not supplied, is usually difficult to interpret and understand. This lack of quantification can be alleviated by including additional indices, such as system well-being indices. The system, whether it is a generation, transmission, generation/transmission or distribution system, is classified into several operating states, namely, system healthy, system marginal, and system at-risk. These states are based on the model proposed in an EPRI Composite System Reliability Evaluation report and provide a framework to evaluate the overall power system performance. The system well-being indices will help to provide valuable information to both system planners and operators on (1) at what point the system is operating, and (2) how far the system is from experiencing risk. In other words, we know where the cliff is, but we also need to know how far we are from the edge of the cliff.

4.4.4.6 System data collection and reliability monitoring.

Continuous monitoring of bulk system reliability performance at both the present time and in the changing future is vital if present reliability levels are to be maintained. In order to assure reliability in a competitive environment, we need to (1) collect the electric system's performance data at each major load delivery point and (2) collect comprehensive component performance data. It is therefore important to continue to encourage the support of current data collection efforts such as NERC's GADS Generation Availability Data System and the Canadian Electricity Association (CEA) work to coordinate a comprehensive collection of generation, transmission and distribution outage data. Fast knowledge extraction techniques and fast data exchanges between control areas and for regional security coordination are also required to extract the intensive information in large data bases which are crucial for the operation of the power system.

Real time system operating information collected by monitoring systems, such as the Wide-Area Measurement System (WAMS), is critical to understanding system reliability events. The data collected following a system disruption or near miss will provide better understanding of what actually happened during various contingencies. Prevention or remedial actions can then be devised to deal with similar situations in the future.

Data collected from power systems may also be used to develop power-quality indices. One recently proposed project will develop power-quality indices from measurements. This project, involving a group of electric utility companies, the Electric Power Research Institute, and Sandia National Laboratories, will collect and analyze data from transmission systems in the Southeastern U.S. Not proposed at this time is to match reliability indices computed by probabilistic tools to measured indices, which would be useful in providing model validation and feedback for model improvements.

The importance of reliability data processing methods is equally significant as the development of the calculation methods. A useful database must emphasize on the correctness and the quality of the data. Very little attention has been given to the uncertainty in these collected data. This uncertainty may be introduced by the selection of window sizes, number of samples, etc. The challenges in the future are to develop proper techniques to filter bad data and develop experimental distribution of these reliability data.

5. Conclusions And Recommendations

North American power systems were driven to the limits or beyond the limits of capacity and stability by factors largely beyond operators' control. The breakups of the Western U.S. power system during the summer of 1996, price spikes in the Midwest during the summer of 1998, the New York City outages of 1999, and other recent adverse reliability events provide hard evidence that these outages underscore the need for improvements. The following techniques, tools, and methodologies are recommended:

1. Better mathematical and simulation modeling.

2. Better collection, analysis and extraction of system performance data, both static and dynamics.

3. Better collection, analysis and extraction of component performance data.

4. Better system controls.

5. Better short-term (minutes to days) planning and operating tools.

6. Better long-term (days to years) planning tools.

7. Better maintenance planning.

New or better tools that can help to develop operational strategies by complementing short term planning with long term planning based on the probabilistic approach.

As restructuring continues, the types of reliability problems occurring are also changing. We need fresh insight and new ideas regarding how best to deal with these new reliability events and the uncertainties associated with them. The goal of current and proposed research development and demonstration is to provide useful, timely information to the decision-making process.

In sections 4.2 and 4.4.3, areas of fundamental research that are needed to further the goal of accommodating uncertainty in planning and operations are summarized. These research needs are essential to developing tools and techniques that will be required by the grid of the future to accommodate uncertainty, but this basic research is not likely to be funded by the private sector, since the return on investment cannot match the funds required unless factors such as public good and national security are included. Federal funding will be required to advance our understanding and develop useful technologies in these areas.

Power system operators will also need practical tools as soon as possible to aid them through the difficult transition to a restructured electric energy market. Immediate actions that can promote this goal include:

1. Finding short-term developments that will yield useful tools to aid system operators through this transition period, i.e., on the order of one or two years.

2. Leveraging existing accepted tools available from commercial vendors, DOE labs, from research institutions and academia.

3. Promoting interactions and the opportunity for collaborations among utilities, power providers, ISOs, regional reliability councils and research institutions, including DOE labs, academia, and commercial tool providers.

Important immediate steps in developing useful tools, techniques, methods, and models to accommodate uncertainty include these actions:

1. Build useful, quality-assured databases of power systems and power system elements up to and including national scales. Provide a means and mechanism to maintain these databases.

2. Work with ISOs, regional reliability councils, and system operators to identity useful, risk-based, real-time tools that are needed now.

3. Work with operators to identify and develop best ways to present uncertainty information to system operators.

4. Continue to survey and evaluate existing models, tools, and methods for uncertainty applications.

A reliable electric power system is essential to the growth and well being of our national economy. To assure this reliability, federal funding will be required for basic research to develop new technologies to assure reliability and demonstrate the effectiveness of these new technologies. Without this funding and the technological solutions that will result, the reliability of the nation's electric power system will degrade as uncertainties that accompany restructuring grow.

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