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Consortium for Electric Reliability Technology Solutions

Grid of the Future White Papers

Project Executive Summary

Prepared for the
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Prepared by
Joseph Eto, Lawrence Berkeley National Laboratory

CERTS Grid of Future Project Team

Carlos Martinez, Vikram Budhraja, Jim Dyer, and Mohan Kundragunta
Edison Technology Solutions
Joseph Eto, Chris Marnay, and Frank Olken, Lawrence Berkeley National Laboratory
Brendan Kirby, John Kueck, and Jim Vancoevering, Oak Ridge National Laboratory
John Hauer, Jeff Dagle, and Kelvin Chu, Pacific Northwest National Laboratory
Robert Thomas, Fernando Alvarado, Anjan Bose, Hsiao-Dong Chiang, Chris DeMarco,
George Gross, Robert Lasseter, Shmuel Oren, Tom Overbye, Mangalore Pai,
Kevin Tomsovic, James Thorp, and Pravin Varaiya,
Power Systems Engineering Research Center
Marjorie Tatro, Abbas Akhil, Patricia Cordeiro, Mark Ivey, Dianne Marozas, Orman
Paananen, Doug Smathers, and Kevin Stamber, Sandia National Laboratories

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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.

Philip Overholt
Program Manager
Transmission Reliability Program
Office of Power Technologies
Assistant Secretary for Energy Efficiency and Renewable Energy
U.S. Department of Energy

[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.

Executive Summary for the Grid of the Future White Papers

The U.S. electric power system is in transition from one that has been centrally planned and controlled to one that will rely increasingly on competitive market forces to determine its operation and expansion. Unique features of electric power, including the need to match supply and demand in real time, the interconnectedness of the networks through which power flows, and the rapid propagation of disturbances throughout the grid pose unique challenges for ensuring the reliability of the system. These challenges are likely to become even more difficult in the future. As the system reliability and electricity marketplace events of recent years demonstrate, the reliability of the grid and the integrity of the markets it supports are integral to the nation's economic well-being.

In 1999, the Department of Energy (DOE) Transmission Reliability Program commissioned the preparation of six White Papers that would establish the foundation for a multi-year program of federally funded research, development, and demonstration (RD&D) projects to maintain and enhance the reliability of the U.S. electric power system as the electricity industry undergoes restructuring:

Drafts of the White Papers were circulated widely among industry stakeholders for review and comment in the late summer of 1999. Culminating with a DOE-sponsored public workshop in the fall of 1999, where the drafts were presented and discussed with industry stakeholders.[4] The final White Papers are available individually from the CERTS website, www.certs.org.

We cannot know the future, but we know that, during electricity industry restructuring, electric system reliability RD&D investments (or the lack of them) will have profound consequences. It is our hope that the six White Papers prepared for this project will provide DOE with a comprehensive framework for moving forward with a renewed federal electric system reliability RD&D program appropriate to the needs of this critical industry in transition.

In the remainder of this Executive Summary, we summarize the scope and key findings from each of the White Papers.

The first White Paper, "***The Federal Role in Electric System Reliability RD&D During a Time of Industry Transition: An Application of Scenario Analysis,***" provides an introduction to the other five White Papers and a framework within which they examine selected RD&D needs in greater detail. The White Paper outlines four scenarios for the future of U.S. electric power system and identifies key areas of needed reliability RD&D for each. It also describes appropriate roles for federal support for these needs and

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

considers how four key uncertainties might affect movement toward each of the scenarios. The four scenarios should not be confused with predictions or even end states that are necessarily desirable. It is assumed that all forecasts by their very nature give plausible/possible estimates. However, the value of the scenarios is in the thinking they inspire regarding what the future could be, and what may be required to get there. Using the scenarios as a starting point, a robust set of federal priorities that is consistent with a variety of possible futures is identified.

The first scenario assumes vertically integrated but functionally unbundled utilities, which is postulated as representative of what will be true in parts of the U.S. for at least the next three to five years. If this were a stable end state, a minimalist federal role in electric system reliability RD&D, consistent with the historic federal role, would be justified. However, this scenario is now understood to be reflective of an electricity industry that is in transition and as a result one in which there are no strong incentives for the private sector to undertake electric system reliability RD&D except that in the very short term to gain competitive advantage. There are no incentives for investments in RD&D that aim to increase the system's ability to support new entrants. There are, in particular, very limited incentives for individual private companies to adopt a system-wide perspective that is the defining characteristic of the U.S. interconnected electric power network. The need for these investments is great as demands to support increased electricity trade continue to place significant and dangerous new pressures on an interconnected power system designed originally to ensure reliable operation.

The second and third scenarios hypothesize two possible end states for the current movement toward regional transmission organizations (RTO) that might emerge in parts of the country during the next three to seven years (and for which partial examples already exist in the form of independent system operators or ISOs). The two end states are distinguished by fundamental differences in the form and organization of the markets they support and even more subtle differences in the institutional roles and responsibilities for maintenance of system reliability. However, they both rely on unbundling and procurement of energy and reliability services through market mechanisms. These features will evoke product and service innovations that cannot be fully anticipated. As evidenced by the lively debate in the industry over the merits of aspects of these scenarios, significant unresolved questions remain regarding the ultimate form of incentives necessary for a stable institutional structure for operation of the grid to emerge. So the scenarios are offered not so much as predictions but as extreme characterizations of selected elements of the industry debate in order to examine likely RD&D needs.

The authors are guardedly optimistic that, if constituted properly, the proposed RTOs and supporting industry could emerge with appropriate incentives to invest adequately in ongoing electric system reliability RD&D needs (though there will still be a federal role in monitoring these activities and complementing them with longer-range ones). They anticipate significant advances in market-enabling technologies and tools. However, in order to reach a steady state, substantial federal investments are needed in electric system reliability RD&D in support of the creation of effective and efficient institutional structures to ensure that robust systems will be put in place. This role is especially important as developments around the country proceed because no private party is in a position to pursue the research needed and because there is an acute need for unbiased research in view of its ultimate commercial implications. In addition, because it will take some time before these institutional issues are settled, gaps in technology RD&D are more likely to develop while the industry is in transition. Thus there is a compelling rationale for federal RD&D, during this transition period, to maintain adequate levels of investment in electric system reliability RD&D. This RD&D should be consistent with a move toward greater reliance on market mechanisms to organize planning and operation until eventual structures for supporting RD&D emerge.

Finally, a fourth scenario is developed to capture the consumer revolution that is taking place as a result of recent advances in small-scale generation, storage, and end-use load-control technologies. This scenario postulates substantial increased reliance on these technologies to the point where, in some areas seven to 10 years from now, generation from smaller-scale sources accounts for 20% or more of new generation. The electric system reliability RD&D needs associated with this scenario are more significant and fundamental than those called for in the first three scenarios. They entail a radical re-examination of the basic tenets of distribution system planning and operation. As a result, there is a special need for a federal role in RD&D in this area to explore and demonstrate advanced system integration and control concepts. As in the first scenario, the current state of the industry in transition provides limited incentives for only a very narrow range of investments. In addition, current regulatory practices provide powerful incentives to distribution companies to actively discourage customer adoption of generation, storage, and load-control technologies because they reduce sales of electricity.

The White Paper concludes that the federal government has special responsibilities for ensuring adequate investments in electric system reliability RD&D during industry restructuring. Once a stable industry structure with vibrant private-sector RD&D is established, the federal government should assume its historic role of supporting very long-range RD&D activities to complement the private-sector’s RD&D investments. During a time of industry transition, however, the private sector faces significant uncertainties that dramatically reduce and narrow the scope of its willingness to invest in RD&D. Thus, without federal support, significant RD&D gaps are likely to emerge. Equally importantly, unbiased federal RD&D is needed to help inform decision makers whose actions will have lasting consequences for the future reliability of the electricity industry. Federal RD&D should be market enabling, not market determining. In view of the importance of electricity grid reliability to the nation’s economy and welfare, these factors now call for an increased federal role in electric system reliability RD&D.

The second White Paper, "***Review of Recent Reliability Issues and System Events,***" establishes the linkage between recent system reliability events and industry restructuring. Specifically, the White Paper reviews, analyzes, and evaluates critical reliability issues as demonstrated by recent disturbance events in the North America power system. The system events are assessed for both their technological and their institutional implications. In doing so, this White Paper vividly reminds us of the interconnectedness of the electric power system and of our dependence on cooperation and coordination among parties to ensure its reliable operation.

Eleven major disturbances are examined. Most of them occurred in the last decade. The two major disturbances in 1965 and 1977 are included as early indictors of technical problems that persist to the present day. The issues arising from the examined events are, for the most part, presented as problems and functional needs.

A key strategic challenge is that the pattern of technical needs has persisted for so long. Anticipation of industry restructuring has, for more than a decade, been a major disincentive to new needed investments in system capacity. It has also inspired reduced maintenance of existing assets. A massive infusion of better technology is emerging as the final option for continued reliability of electrical services. If that technology investment will not be made in a timely manner, then that fact should be recognized and North America should plan its adjustments to a very different level of electrical service.

It is apparent that technical operations staff among the utilities can be highly effective at marshaling their forces in the immediate aftermath of a system emergency, and that serious disturbances often lead to improved mechanisms for coordinated operations. It is not at all apparent whether and how such efforts can be sustained through voluntary reliability organizations in which personnel external to these organizations do most of the technical work.

The August 10, 1996 Breakup of the Western interconnection demonstrates the problem. It is clear that better technology might have avoided this disturbance, or at least reduced its impact. The final message is a broader one. All of the technical problems that the Western Systems Coordinating Council (WSCC) identified after the August 10 Breakup had been reported earlier, along with an expanded version of the countermeasures eventually adopted. Through a protracted decline in planning resources among the member utilities, the WSCC had lost a substantial portion of its collective memory of these problems and much of the critical technical competence needed to resolve them. The market forces that caused this situation pervade all of North America to a greater or lesser extent. Similar effects might be expected in other regions of the world as well, though the particular symptoms will vary.

Such institutional weaknesses are undeniably a transitional phenomenon that eventually will be remedied as new organizational structures for grid operations evolve, and as regional reliability organizations acquire the authority and staffing consistent with their expanding missions. This will provide a more stable base and rationale for infrastructure investments. Difficult issues still remain in accommodating risk and in reliability management generally. Technology can provide better tools, but it is National policy that will determine if and how such tools are deployed. That policy should consider the deterrent effect that new liability issues pose for the pathfinding uses of new technology or new methods in commercially driven electricity markets.

The progressive decline of reliability assets that preceded many of these reliability events, most notably the 1996 breakups of the Western system, did not pass unnoticed by the Federal utilities and by other Federal organizations involved in reliability assurance. Under an earlier program, the DOE responded to this need through the Wide Area Measurement Systems (WAMS) technology demonstration project.   This was of great value for understanding the breakups and restoring full system operations. The continuing WAMS effort provides useful insights into possible roles for the DOE and for the Federal utilities in reliability assurance.

To be fully effective in such matters the authors recommend DOE seek closer "partnering" with operating elements of the electricity industry. This could be approached through greater involvement of the Federal utilities in DOE's research activities, and through direct involvement of the DOE Laboratories and academic universities in support of all utilities or other industry elements that perform advanced grid operations. The White Paper offers four proposals as candidates for this broader DOE involvement:

1) National Institute for Energy Assurance (NIEA) to safeguard, integrate, focus, and refine critical competencies in the area of energy system reliability;
2) Dynamic Information Network (DInet) for reliable planning and operation, which would be an advanced demonstration project building upon the earlier DOE/EPRI Wide Area Measurement System (WAMS) effort, plus advanced technologies for data mining, visualization, and advanced computing;
3) Modeling the Public Good in Reliability Management, which would involve exploratory research into means for representing National interests as objectives and/or constraints in the effective deployment of the newly developed decision support tools for reliability management; and
4) Recovery Systems for Disturbance Mitigation to lessen the impact of system disturbances and to lessen the dependence upon preventive measures.

All of these activities would take place at the highest strategic level, and in areas that commercial market activities are unlikely to address.

The third White Paper, "***Review of the Structure of Bulk Power Markets,***" examines structural features and current issues facing recently restructured electricity markets. In doing so, this White Paper elaborates on the future industry scenarios considered in the first White Paper. However, more importantly, it provides succinct summary of changes to date in some of the leading restructured markets both in the U.S. and to a limited extent internationally.

The White Paper begins by contrasting historical operation of bulk power markets with the new institutional challenges involved in operating these markets in a restructured industry. Historically, the bulk power market structure was dominated by vertically integrated utilities, which were granted monopoly franchise service territories. The combined economic and reliability performance of utilities was judged in a holistic fashion by regulators who approved tariffs that customers were obligated to pay. One of the objectives of restructuring is to introduce competition into electric power markets in order to improve economic efficiency.

Restructuring is not changing the physical needs of the power system. The functions previously performed by the vertically integrated utility must be accommodated by the new market structure. These functions range from assuring an adequate electricity supply through multi-year planning of the generation and transmission system, to meeting shorter term forecasted load by deploying existing resources through unit commitment, to assuring system security through automatic generation control, and to operating the transmission system by controlling ancillary services such as reserves and blackstart capability.[5]

The White Paper reviews six restructured market systems: 1) California; 2) Pennsylvania, New Jersey, Maryland (PJM); 3) New England; 4) United Kingdom; 5) Alberta; and 6) Australia.

In California, two separate new markets have been created: a “Power Exchange” or wholesale market for power, and an unbundled ancillary services market conducted by the ISO, in addition to markets for congestion management and real-time balancing energy. These markets have been experiencing problems such as the exercise of apparent market power and too few bids for some ancillary services. The grid is experiencing congestion in some areas, and in some cases large generators take advantage of congestion rules. The ISO has instituted several “fixes” to deal with these problems and has obtained FERC

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[5] The controller of the physical system, of necessity, has control of the commercial transactions; no generator or load can interact with electricity markets unless the system operator facilitates such interaction. Consequently, a basic feature of the restructured industry is that the system operator must be isolated from commercial market pressures. At a minimum, a "code of conduct" is required that prevents the system operator from providing preferential treatment for generation or transactions that are owned or sponsored by the system operator’s company. At a maximum, the system operator can be an independent, commercial organization, an Independent System Operator (ISO).

orders in some instances, but there are still opportunities that continue to be available for players to “game” the system.

The PJM market has made a transition from a zonal to a nodal system where temporal spot prices are calculated for some 2,000 nodes. When the system is congested, these prices may exhibit large differences among themselves. This differences allows traders to “buy through” congestion. Another market feature allows traders to collect “rent” on transmission lines as a hedge against congestion. During heat storms in the summer of 1999, rotating blackouts were required after a single contingency due to lack of generation in an area where nodal prices were not yet functioning. It is hoped that these problems will soon be addressed by the market as it matures and new generation is built in response to market forces in the areas of need.

In New England, new generators have had difficulty in gaining access to the grid apparently because of firmly entrenched market power of existing market participants. It seems likely that there will be a series of appeals to FERC to correct inequities. This process has already started. This will probably delay the maturing and efficient functioning of this market.

In the United Kingdom, a rather complex market has evolved. It appears this market provides ample opportunity for gaming because of its complexity and is being blamed for high electricity prices. As a solution, a Power Exchange and other changes are being developed. The target date for the changes to the existing system is slipping into the fall of 2000.

The Alberta system has one zone for the entire power pool. A complex system of legislated hedges was put into place when the system was first implemented to put a damper on market power and to achieve economic goals. The planning process has also ensured that potential stranded assets are dealt with and costs are recovered. Transmission upgrades are needed because the bulk of the generation is in the North and the bulk of the load is in the South, however, the need for upgrades to the North – South corridor will be questionable if the market is effective in bringing new generation to the South.

Australia has a relatively simple system where ancillary services are contracted by the National Agency rather than made part of the market. Suppliers bid into a pool with an essentially real time market; suppliers may revise their offers until a short period of time before the real time energy auction. There is no day-ahead market. The grid is divided into four zones and there is a method for calculating locational prices. The federal government has stringent codes that apply uniformly across the nation on how the market is to be operated. The market is working well in reducing costs, and there does not appear to be excessive exercise of market power or gaming. The ultimate plan is for all customers to have access to the wholesale market if they wish.

It is tempting, but incorrect, to view the Midwest price spikes during the summers of 1998 and 1999 as reliability events. They certainly invite investigation to understand what happened to drive prices to above $7000 and $9000/MWh, respectively. Generation was nearly inadequate to serve price insensitive load and, given the confluence of events occurring simultaneously, prices rose in response. However, high prices, per se, are not reliability events. If the system operators were diligent in maintaining contingency reserves, if they resisted economic and political pressure to use contingency reserves to serve load (which might make the system unable to deal with the next contingency), then security was not impacted. As events actually unfolded, security may have been threatened, but in the end was not impacted. Some interruptible customers may have been curtailed in line with their tariffs, but *system* reliability was not necessarily impacted. No firm customers were left unserved. This is in distinct contrast to conditions in MAPP in June of 1997 when the physical system came close to collapse or the WSCC events in July and August of 1996 when the physical system actually did collapse.

The price spikes indicate a lack of adequate generation; the system collapses indicate an insecure system. Restructuring tries to address adequacy through markets. Clearly these are not fully functional markets when prices rise to 500 times their normal values and there is no demand elasticity. But this is an indication of market failure (i.e., absence of meaningful demand response), not a technical failure of the power system. The simple expedient of allowing loads to participate in real-time energy markets would likely mitigate the price spikes.

Restructuring bulk power markets dramatically intensifies the need for federally sponsored research into electric system reliability. Private entities have greater incentive to perform research and develop products but *only* if the effort will result in profit exclusively for the investor. A competitive market participant cannot afford nor will it want to invest in research that will benefit its competitors as well as itself. It is better off waiting for others to incur the expense. Technologies that increase the capacity of the community transmission system will only be developed through federally supported research. Similarly, technologies that assist the system operator in observing and controlling the power system will allow the system to provide greater throughput while maintaining reliability. These will only be developed through federally supported research. Federal support is needed to overcome the limiting technical and institutional barriers that are preventing load from being used as a resource to support bulk power system reliability. This last area would likely provide the greatest and most immediate return on investment.

Federally supported research is required to further the design of bulk power markets themselves. Metrics are needed to assess the overall performance of markets and allow different market structures to be compared. Computer based simulation and modeling is needed to analyze the expected behavior of markets, both for macroscopic behavior and to analyze the impact of specific rule changes. Markets are inherently human activities and interrelated energy and ancillary service markets are particularly complex ones. Modeling and computer simulation can only go so far. Experimental economics studies are required to extend the analysis of market designs that assure reliability.

Load control (and distributed generation) is an underutilized resource for addressing bulk power system reliability. At present, load is not responsive to the hourly price because it is denied access to real time markets. New communications, control and metering technology may make it possible for loads to respond appropriately to market signals and to participate in ancillary service and real-time energy markets. This could reduce the need for new generation and transmission investments, free generation to provide energy, greatly mitigate price spikes, and relieve transmission congestion. Technical and institutional obstacles must be overcome. Services must be defined in terms of actual requirements, not in terms of the central generation resources that have traditionally supplied them.

In the near term, research is required to define ancillary service requirements and metrics. Work in this area is going extremely slowly, primarily because it is being performed on a voluntary basis by entities that perceive commercial benefit from participating. The basic problem is of competing individuals being unable to invest in a community solution. Research is also needed in market technologies to enhance transmission capacity, planning tools and in market structures to ensure long term reliability. In addition, there are major needs associated with the quantification, measurement, and metering of many of the services.

The fourth White Paper, "***Real Time Security Monitoring and Control of Power Systems,***" outlines the scope of technical issues, challenges and opportunities in the area of real-time security monitoring and control (RTSMC) of power systems in the restructured electricity industry. RTSMC refers to bulk power system planning and operational procedures, which must be put in place to safeguard electric power systems against disturbances. That is, since disturbances propagate through the electric grid at essentially the speed of light, the system must be planned and operated in a manner to ensure that it can accommodate unexpected failures of equipment. As the industry undergoes major transformations that are replacing the entrenched vertically integrated utility structure with new organizations offering unbundled services, there are wide ranging impacts on RTSMC.

This White Paper, thus, builds on both the reliability events discussed in the second White Paper (which reviewed situations where RTSMC was inadequate) and the emerging market structures discussed in the third White Paper (which described the changing institutional settings in which this monitoring and control must take place). Specifically, the objectives of this White Paper are to:

1. Identify key challenges and issues of concern in real-time secure operations of the restructured power industry;
2. Define the scope of research required to meet the needs of real-time operations in the restructured environment; and
3. Analyze, assess and evaluate possible strategies for effectively meeting the challenges in RTSMC.

The first section of the White Paper explains the framework for RTSMC. The counterpart of power system reliability in real-time operations is *security* – the ability of the power system to withstand contingencies. The principal role of power system control is to maintain a secure system state, i.e., one that can withstand each one of the specified contingencies. The RTSMC system is a collection of processes, computing equipment, measurement devices and communications that have been assembled to provide the means of accomplishing this role. The RTSMC system uses real-time measurements to identify whether or not the power system state is *normal*; this function is called *security monitoring*. If the state is normal, the RTSMC system determines whether or not it is secure; this task is termed *security assessment.* A broad range of control actions is deployed to ensure reliable around-the-clock tracking of the load by the generation. These actions cover a wide time spectrum resulting in a continuum of control actions from the very fast controls in the protection system to the slower controls of generators to provide the automatic generator control function.

The second section of the White Paper is devoted to the multitude of challenges and opportunities in RTSMC under the unbundled regime. An overriding issue is the data problem in the restructured environment. There are two main aspects to this problem. On the one hand, the problem manifests itself in terms of making available all the data required for effectively discharging the RTSMC functions. This is rather sensitive due to the conflicts between physical system data and market data. The task of maintaining a reasonable balance between security maintenance and market integrity is a daunting challenge. The other aspect of the issue is the *data overwhelm* problem due to the vast amounts of data that need to be managed in RTSMC. The volumes of data will increase, notwithstanding the difficulties of data acquisition due to the market-physical conflict issue. The section explores the challenges and opportunities in incorporating the advances in computer, communications and measurement/instrumentation technology and the state of the art in control theory. Critical attention is paid to the impacts of the interactions of the physical delivery layer of the power system, the market layer being established by the new organizations in the restructured environment and the communication, monitoring and control layer in which the RTSMC mechanisms and processes are housed. The impacts of the increased volatility on the system are given special attention.

As the industry restructures and new paradigms for its operation are established, the need to ensure the security of the power system will continue to require improved controls.

The third section is devoted to the reexamination of control laws in light of the changing environment and to take advantage of the opportunities from incorporating new technology advances. In particular, the impacts of developments in three important areas – substation automation, FACTS devices and dispersed resources – on control schemes are discussed in detail. The applications of advances in control theory in the area of robust control are explored with a view of formulation of effective control mechanisms for the restructured power system. The impacts of advances in communications technology on the deployment of faster controls are examined.

The fourth section of the White Paper focuses on possible strategies in the area of analytical and software tools to deal with the many aspects of RTSMC in the restructured environment. The *data overwhelm* problem is examined in terms of visualization tools. On the analytical side, the tools for information management, state estimation, voltage security analysis and available transfer capability are examined in detail. The software engineering aspects of RTSMC tools are given special consideration because the successful and reliable operation of the power grid will be increasingly dependent on effective software engineering of the data acquisition, communications, computation, control and market operation systems. Additional aspects of the discussion include model development and validation, the needs in the training simulator tools arena and some potentially useful approaches from complex system theory.

The final section of the White Paper is a summary of the major thrusts of the research needs and strategies for RTSMC in the restructured environment.

The fifth White Paper, "***Accommodating Uncertainty in Planning and Operations,***" discusses a cross-cutting topic, uncertainty, which is an intrinsic, yet not fully appreciated, feature of all system planning and operational decisions. The authors contend both that uncertainty currently is not treated adequately in electric system planning and operations, and that it will increase in complexity and significance in a restructured industry. The White Paper then goes on to identify technologies and methods to accommodate or better manage uncertainties to ensure reliable electric power. It also discusses market-supplied solutions to planning, operations, and reliability issues.

The White Papers uses the term "uncertainty" in a probabilistic sense: uncertainty is the impact of randomness in the environment and results in a 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. These errors affect planning and operations in both the short-term and long-term.

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 (hours or less) 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 short- (days) and long-term (years) planning. Yet a fundamental change is underway in the electric power industry with respect to 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 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 under 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 historical data to predict future system performance, and to deal with existing and new unknown uncertainties.

The White Paper further develops and adds to recommendations prepared earlier by the Secretary of Energy's Advisory Board (SEAB)[6] on the reliability of the electric power system, including:

1. Characterization of 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 impacts 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.

[6] "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.

In addition to these recommendations, the White Paper adds:

5. 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 system well being, which will provide a framework to evaluate overall system performance as well as information to system planners and operators.
6. 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.

The White Paper concludes with a list of needs for technologies that can be used to better manage the sources of uncertainties in planning and operations for power systems. These 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 period. Transfers of existing technology from DOE labs, along with collaborations among commercial vendors, research institutions, including academic universities, utilities and power providers, and DOE labs are proposed to accelerate development of needed tools, models, and methods for accommodating uncertainty.

The sixth White Paper, "***Interconnection and Controls for Reliable, Large-Scale Integration of Distributed Energy Resources,***" completes the development of the market and institutional settings described in the fourth scenario of the first White Paper. The White Paper then uses the utility and customers needs met by these markets to identify the technical requirements of a transition to large-scale integration of DERs into the existing distribution infrastructure for purposes of maintaining or enhancing electricity system reliability. As discussed in the first White Paper, the RD&D needs required to support such a future are perhaps the most fundamental of all because they entail a complete re-conceptualization of the planning and operation of electric distribution systems.

The White Paper defines DERs as active devices that supply energy and are installed as part of the electricity distribution (rather than transmission) system. DERs are distributed in the sense that they are dispersed; consider, for example, emergency generators owned by individual customers. DERs include generation sources, such as fuel cells, micro-turbines, photovoltaics, and hybrid power plants, as well as storage technologies such as batteries, flywheels, ultra capacitors and superconducting magnetic energy storage. Many electricity customers have demand-side management programs to control energy consumption; dynamic reactive power control devices and end-use load controls used to manage demand should also be considered DERs. No specific size range has been defined for DERs, but most distribution systems would have difficulty accommodating distributed generating resources larger than 10 MW/MVA at any single location; many systems may have even lower limits.

The White Paper begins by defining the five most likely scenarios through which DER will gain market acceptance:

1. Back-up generators in an expanded role relative to the current system;
2. Local micro-grids;
3. Interconnected local micro-grids;
4. Utility grids with DER integrated to meet Transmission and Distribution (T & D) needs; and
5. Local micro-grids integrated with utility T&D grids.

The local micro-grid is an important concept in the DER market vision. A micro-grid is a cluster of micro-generators and storage devices operated as a single unit, independent of or interconnected with the utility T&D grid. Micro-generators will likely operate as "islands" at first because of a lack of interconnection standards and current regulatory policies that provide utilities with incentives to discourage interconnection. However, in the future, the White Paper envisions micro-generators interconnected with T&D grids and other micro-grids.

The White Paper then identifies current barriers to development of these markets:

1. High cost and uncertain performance of DER technologies;
2. Lack of uniform standards for power quality and lack of information on DER power quality characteristics;
3. Lack of tools to control DERs for peak-shaving applications;
4. Lack of tools to plan for and operate DERs to defer transmission and distribution upgrades;
5. Lack of information regarding control of significant numbers of DER technologies;
6. Lack of standards and protocols to permit DERs to participate in competitive energy markets;
7. Lack of information on demand-side management as a DER;
8. Lack of knowledge and institutional arrangements necessary to coordinate utility and DER operations.

Next, the White Paper identifies the areas of research needed to overcome these barriers and facilitate the greatest penetration of DERs. These include:

1. Inexpensive, standardized power electronics converters and controls;
2. Islanded (i.e., isolated from the grid) and integrated protection and control schemes;
3. Islanded and integrated real-time MW and voltage regulation for DERs;
4. Islanded and integrated real-time dispatch and control;
5. High-quality power for both islanded and integrated operations;
6. Wide area real-time data communication protocols and infrastructures;
7. Integration of demand-side resources in electricity markets;
8. Independent identification of DER operational requirements; and
9. Field testing of all the above technologies and processes.

The White Paper argues that a special focus for research is needed in the areas of control systems (including sensors and instruments to gather intelligence for real-time power management), and dispatch or coordination among distributed generation resources and utility distribution systems. Research should also include improved modeling techniques to characterize DER technologies and their impacts on the distribution (and, ultimately, the transmission) system.

Taken together, the RD&D tasks identified in this White Paper will lead to technologies that will:
1. Allow customers and utilities to maximize the energy cost benefits from the installed DERs;
2. Facilitate development and implementation of national standards;
3. Meet customer's needs for reliable energy and power quality;
4. Meet electric system needs for energy, ancillary services, and local voltage support; and
5. Provide options for utilities to defer transmission and distribution expenditures and to improve power quality and grid reliability.