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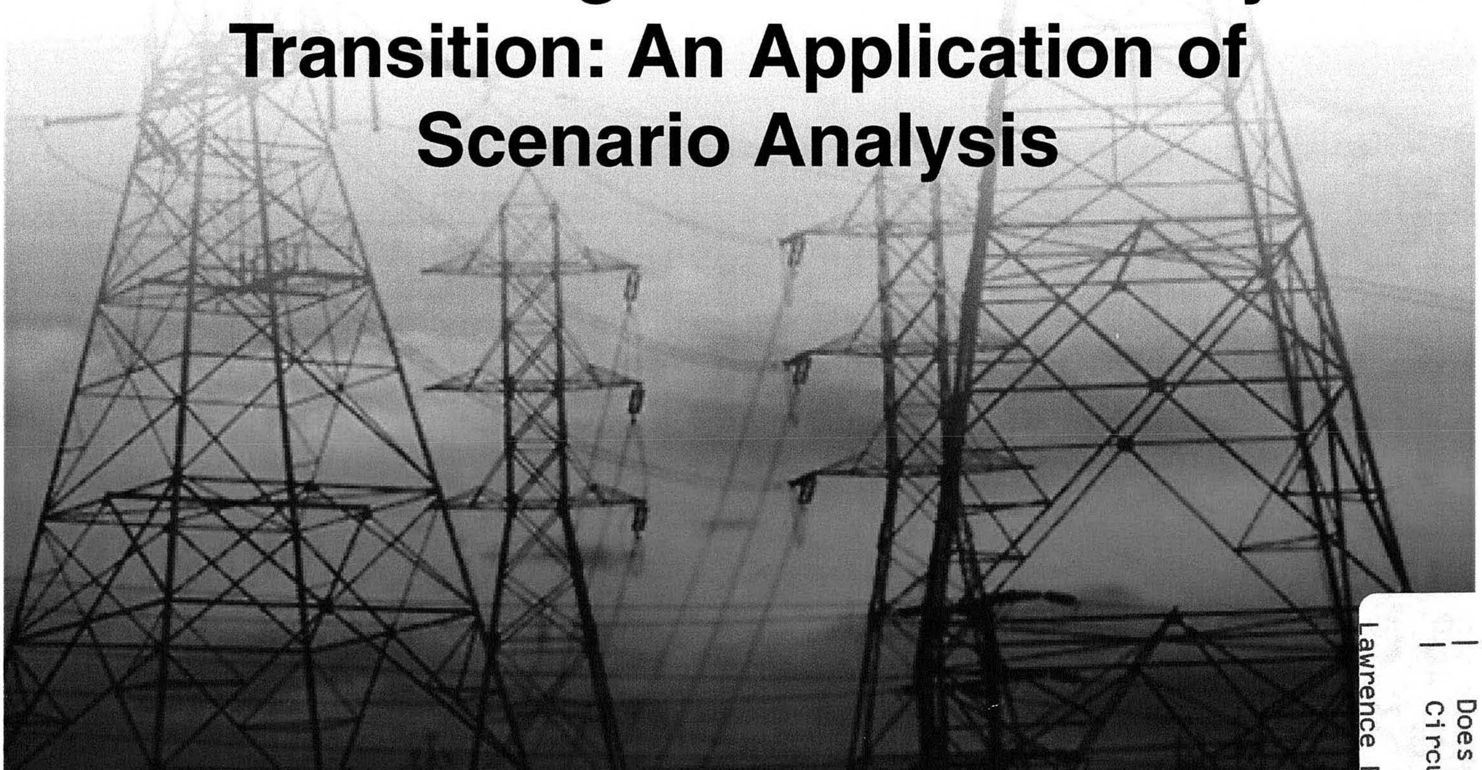
The Federal Role in Electric System R&D During a Time of Industry Transition: An Application of Scenario Analysis



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Grid of the Future White Paper on

The Federal Role in Electric System R&D During a Time of Industry Transition: An Application of Scenario Analysis

Prepared for the
Transmission Reliability Program
Office of Power Technologies
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U.S. Department of 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.

Philip Overholt
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[1] The founding members of CERTS are Edison Technology Solutions (ETS), Lawrence Berkeley National Laboratory (LBNL), Oak Ridge National Laboratory (ORNL), the 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. In addition, Pacific Northwest National Laboratory (PNNL) was tasked to develop a sixth white paper in coordination with CERTS.
[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

AC	Alternating Current
ATC	Available Transfer Capability
DOE	Department of Energy
DC	Direct Current
FACTS	Flexible Alternating Current Transmission Systems
FERC	Federal Energy Regulatory Commission
ISO	Independent System Operator
NAERO	North American Electric Reliability Organization
NERC	North American Electric Reliability Council
NOPR	Notice of Proposed Rulemaking
OASIS	Open Access, Same-Time Information System
RD&D	Research Development, and Demonstration
RTO	Regional Transmission Organization
WAMS	Wide Area Measurement System

Executive Summary

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 reliability events of 1996 and the market events of 1998 and 1999 demonstrate, the reliability of the grid and the integrity of the markets it supports are integral to the nation's economic well-being.

This white paper is one of six commissioned by the Department of Energy (DOE) Transmission Reliability Program to establish a 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. In this white paper, we develop scenarios that represent four possible states of the industry during the next three to 10 years. We outline the RD&D they require and describe appropriate federal roles in making these investments. Specific aspects of the scenarios, their RD&D needs, and federal priorities are explored in greater depth in the other five white papers.[4]

The four scenarios we developed should not be confused with predictions or even end states that we believe are necessarily desirable. We assume that all forecasts are wrong, but that the value of the scenarios is in the thinking they inspire regarding what the future could be, and what is needed 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 can be identified.

The first scenario assumes vertically integrated but functionally unbundled utilities, which we believe is 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 would be justified, consistent with the historic federal role. However, we now judge this scenario 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 will increase the system's ability to support new entrants and there are, in particular, very limited incentives for individual private companies to invest based on the system-wide

[4] The other five white papers are: "Review of Recent Reliability Issues and System Events," by J. Hauer and J. Dagle; "Review of the Structure of Bulk Power Markets," by B. Kirby and J. Kueck; "Accommodating Uncertainty in Planning and Operations," by M. Ivey, A. Akhil, D. Robinson, J. Stamp, K. Stamber, and K. Chu; "Real Time Security Monitoring and Control of Power Systems," by G. Gross, A. Bose, C. Demarco, M. Pai, J. Thorp, and P. Varaiya; and "Interconnection and Controls for Reliable, Large Scale Integration of Distributed Energy Resources" by C. Martinez, V. Budhraja, J. Dyer, and M. Kondragunta.

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.

In the second and third scenarios, we hypothesize two 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 physical 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 we offer scenarios two and three not so much as predictions but as extreme characterizations of selected elements of the industry debate in order to examine likely RD&D needs.

We are guardedly optimistic that, if constituted properly, our hypothetical 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). We 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, to support the creation of institutional structures and systems of incentives that will ensure that robust system 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 a special 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 more stable structures for supporting RD&D emerge.

Finally, we created a fourth scenario 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. We find important parallels between these developments and the emergence of the personal computer 20 years ago. The electric system reliability RD&D needs associated with this scenario are more significant and fundamental than those called for in the previous three scenarios, because 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 scenario one, 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.

We conclude 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 national welfare, these factors now call for an increased federal role in electric system reliability RD&D.

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.

1. Introduction

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 reliability events of 1996 and the market events of 1998 and 1999 demonstrate, the reliability of the grid and the integrity of the markets it supports are integral to the nation's economic well-being.

This white paper is one of six commissioned by the Department of Energy (DOE) Transmission Reliability Program to establish a 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. In this white paper, we develop scenarios that represent four possible states of the industry during the next three to 10 years. We outline the RD&D they demand and describe the appropriate federal role in the investments required. Specific aspects of these scenarios, their RD&D needs, and federal priorities are explored in greater depth in the other five white papers.[1]

This paper is organized in nine sections following this introduction. In section two, we outline criteria and principles for federal involvement in electric system reliability RD&D, which form the basis for our assessment of appropriate federal RD&D activities. In section three, we provide a non-technical introduction to selected features of the U.S. electric power system that are related to reliability, and an overview of institutional options for future operation of the system. These descriptions are the basis for the scenarios. Section four briefly introduces the concept of scenario analysis as a planning tool and describes common elements of the four scenarios we develop in sections five through eight. Following a description of key driving forces for and characteristics of each scenario, sections five through eight outline needed electric system reliability RD&D and the appropriate federal role in supporting these activities. In section nine, we consider the impact of four key uncertainties on each of the scenarios. Section ten summarizes our findings.

[1] The other five white papers are: "Review of Recent Reliability Issues and System Events," by J. Hauer and J. Dagle; "Review of the Structure of Bulk Power Markets," by B. Kirby and J. Kueck; "Accommodating Uncertainty in Planning and Operations," by M. Ivey, A. Akhil, D. Robinson, J. Stamp, K. Stamber, and K. Chu; "Real Time Security Monitoring and Control of Power Systems," by G. Gross, A. Bose, C. Demarco, M. Pai, J. Thorp, and P. Varaiya; and "Interconnection and Controls for Large Scale Integration of Distributed Energy Resources" by C. Martinez, V. Budhraja, J. Dyer, and M. Kondragunta.

2. Criteria and Principles for Federal Support for Reliability RD&D in a Restructuring Electric Industry

The objective of the Grid of the Future white papers is to identify the future reliability RD&D needs of the U.S. electric power industry. Some RD&D needs can, will, and should be met by the private sector without public funding; others can only, and in some cases should only, be met with public funding. In many cases, a combination of private and public funding is appropriate. To set the stage for the discussions in this and the other five white papers, we present below the standards we use to identify reliability RD&D appropriate for federal funding. The standards consist of two criteria and three principles.

2.1 Criteria for Federal Funding of Reliability RD&D

The criteria below are used to determine which RD&D efforts are appropriate for federal support. For an activity to qualify, it must:

Advance national interests (criterion 1). Economic efficiency, economic competitiveness, social welfare, public safety, environmental protection, and national security are all national interests that must be advanced by publicly funded reliability RD&D. Without these benefits, there is no reason to consider federal funding.

Be unlikely to be pursued by the private sector (criterion 2). Market participants will act based on economic self-interests, as shaped by economic regulation and commercial law. Federally funded research should enable and complement, not compete with, privately funded RD&D activities.

In short, to justify federal support for an RD&D activity, there must be compelling evidence that it will advance national interests and that these interests will not be advanced adequately by the private sector.

2.2 Principles for Federal Funded RD&D

We use the following principles to determine which RD&D efforts the private sector is unlikely to support. Often, more than one principle may be involved. The private sector is unlikely to fund activities when:

Benefits take too long to realize (principle 1). The private sector has short time horizons and is generally unwilling to wait for benefits. By contrast, basic research may take many years of continuous support before commercial products can begin generating returns. Private-sector time frames for returns on investments are especially short during periods of rapid structural change in an industry when many firms become cautious about their futures.

Benefits are too uncertain (principle 2). There is significant risk in committing funds to research because success is not guaranteed. If risks cannot be sufficiently diversified through pooling with other private-sector participants, individual players are unlikely to fund research that may, for example, lead to products that do not repay their research costs (even though use of the same basic research by others may ultimately be profitable). In addition, structural change in the industry makes it harder to tell what the ultimate market for or profitability of a product might be. Private market participants may face insufficient financial incentives to invest because the structure of the industry is in flux.

Benefits cannot be captured adequately by a single private-sector market participant or by a group (principle 3). Public goods features of RD&D may be difficult to capture through existing patent and copyright laws. The likely beneficiaries of RD&D are unable to support it because their mission is not adequately clear or because they are under-funded or under-staffed. This, in turn, may be a function of an industry in transition, but it may also be a permanent structural shortcoming of whatever institutions are ultimately put into place to safeguard electric system reliability.

Public interest may be better served by those without financial interest in the outcomes (principle 4). Private interests have powerful (and appropriate) incentives to conduct research that will maximize their well-being. The public goods aspects of reliability-related RD&D suggest that there is a role for unbiased, third-party performance and evaluation of research, which otherwise will not be undertaken and which without societal gains would be lost.

At the extreme, market solutions may not be feasible because certain reliability services are fundamentally public goods. For example, markets for the restoration of service following outages are unlikely to arise from private market participants acting in their own self-interest because the system is inherently integrated.[2]

There is a mandate (principle 5). Although it is hard to imagine cases in which the federal government would mandate reliability RD&D that does not meet the two criteria above, a mandate can be understood as prima facie evidence that public funding is appropriate.

As an example, the recent report from the Secretary of Energy Advisory Board Task Force on Electric System Reliability made several technical recommendations to the Department of Energy (DOE).[3] These recommendations do not have the force of law, but they do represent clear and unambiguous high-level direction regarding what the Task Forces believe is appropriate for DOE to fund.

[2] This hypothesis may be tested as the use of distributed generation increases. See scenario 4 in section 8.
[3] "Maintaining Reliability in a Competitive U.S. Electricity Industry, Final Report of the Task Force on Electric System Reliability." Secretary of Energy Advisory Board, U.S. Department of Energy. September, 1998.

2.3 Applying Criteria and Principles to Scenario Findings

Using the criteria and principles above to justify federal support for reliability RD&D means we need to describe the expected benefits of RD&D activities and explain exactly why the market alone will not effectively capture them. We could do this by reviewing privately funded R&D activities to determine what activities the market is supporting. However, we will always be limited in our understanding of the full scope privately funded RD&D currently under way because of its proprietary nature. In addition, placing too much emphasis on current activities may be misleading because the industry is changing rapidly.

Therefore, we take the approach of identifying specific reasons why the market might not work properly in each of the scenarios. We describe the responsibilities and incentives of market participants for RD&D in each scenario and use these descriptions to identify the reasons why the market alone may not provide adequate incentives for appropriate investment in RD&D. We make explicit reference to principles listed above in our analysis.

The recommendations developed in this white paper are limited to RD&D activities that might be undertaken by DOE's technology programs. We do not address activities that might be appropriate for federal support through the utilities the federal government owns (BPA, TVA, WAPA, etc.). The federal government has a long history of investment, through these utilities, in reliability related human and physical infrastructure, including electric system reliability RD&D. A discussion of appropriate federal roles for RD&D conducted through or in conjunction with these utilities is beyond the scope of this paper.[4]

[4] See, however, another white paper in this series in which the historic role of federal utilities in electric reliability RD&D is discussed: "Review of Recent Reliability Issues and System Events," by J. Hauer and J. Dagle.

3. Electric System Reliability Concepts and Restructuring Issues and Options

The scenarios developed in this paper describe possible organizational and institutional characteristics of a future U.S. electric power system. This section introduces the requirements of reliable electric power system operation and aspects of the institutional/structural options that are under discussion for meeting these requirements in the future. This discussion gives background for the scenarios and the electric system reliability RD&D needs that are later identified in our analysis of them.

3.1 Electric Power System Reliability Concepts

Electricity production is the ultimate in "just-in-time" manufacturing. Electricity must be produced in real time in quantities that exactly match continuously varying demands because storage is not currently economical (although economical storage technologies are being developed). The product is transported to consumers at roughly the speed of light.

The U.S. bulk power transmission system permits trade across large geographic regions through interconnected networks of transmission lines. Power flows through the grid are initiated by injections and withdrawals at predetermined points on the network. However, the specific paths taken by these flows through the network are determined entirely by the laws of physics, which depend on the physical characteristics of the transmission lines, and on the specific pattern of injections and withdrawals. Fortunately, electricity is homogeneous (an electron is an electron is an electron…); electrons injected at one point in the network need not be the same electrons withdrawn at another point.[5] Technologies to directly control aspects of electricity flow have been developed (e.g., flexible alternating current technology systems or FACTS) but are not yet used extensively.[6]

Most bulk power transmission in the U.S. takes place using alternating current (AC). In an AC power system, voltage and current frequency – the two underlying constituents of electric power – must be closely aligned and continuously regulated both to maximize the flow of useful power and to maintain the stability of this flow. The entire electric power system, including generators, transmission and distribution systems, and the myriad electricity-consuming devices to which power is supplied, has been likened to an enormous, interconnected machine in which all the parts operate in unison at a nearly constant 60 cycles per second.

[5] However, the timing, quality, and reliability of electric power are aspects that lead to the creation of many different electricity "products."

[6] Direct current (DC) is a form of electrical energy whose flows can be controlled. High-voltage direct current is currently economic for only long-distance transportation of electricity.

These characteristics of the electric power system create special challenges for ensuring reliable operation. The industry uses two specialized terms, "adequacy" and "security," to describe system reliability.[7] Adequacy refers to "[T]he ability of the electric system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements." In other words, adequacy addresses the need to match demands and supplies precisely given the (current) lack of opportunities to store electricity. Security refers to "[T]he ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements."[8] Security, in other words, addresses the need for protection and redundancy in the system because of the speed at which disturbances can propagate throughout and disrupt the entire system.

Ensuring system adequacy and security requires actions on several different time scales. On the longest time scale, measured in years and months, investments in plant construction (including transmission and distribution as well as generation facilities) and arrangements to ensure fuel supplies must be made to meet expected load growth.

On shorter time scales, a variety of planning and operating decisions are required. At yearly to monthly intervals, maintenance must be undertaken to ensure assets will function when called upon. At weekly and daily time intervals, the need to meet expected loads calls for decisions to start and stop certain classes of power plants that require long start-up and shut-down procedures (the decision to start up a plant is also called "unit commitment").

On a daily and hourly time scale, short-term planning is required to determine the extent to which lines may become overloaded (or congested) and, if an overload or congestion might occur, what adjustments to avoid this situation must be made to the planned dispatch of generation units (or what should be done to curtail expected loads). This planning makes explicit assumptions to account for the possibility of outage in a generating unit or transmission line. "N-1" refers a traditional planning criteria used in these studies, which assumes that the single largest generating unit or transmission line is not available.

On an hourly to minute time scale, decisions must be made to increase or decrease generation output to match expected demand. In addition, because demand varies

[7] Reliability is defined as, "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. Electric system reliability can be addressed by considering two basic and functional aspects of the electric system – Adequacy and Security." "Glossary of Terms." North American Electric Reliability Council. August, 1996.

[8] It is especially important to recognize that our use of the term "security" differs from its use in discussions of critical infrastructure protection where it has to do with deliberate, malicious human actions that might lead to a sudden disturbance or unanticipated loss of a system element. Our use of the word security includes these and several other initiating events, such as unintended operator error, natural phenomena, and random equipment failure.

constantly, excess generating capacity must always be either kept on line ("spinning") or readily available to respond to changes in demand. Decisions about the nature and amount of reserves required are based on explicit consideration of the potential for outages. These reserves are one aspect of an important class of reliability activities called ancillary services.

On a minute to less than one second time scale, manual and automatic fine-tuning actions must be taken to increase/decrease generation so that demand is exactly matched and system frequency is regulated. In addition, because the physical properties of components of the power system (e.g., lines, generators, and loads) can cause voltage and current to move out of alignment (and voltage to drop) and stress the system, special devices and additional sources of generation must be located throughout the system and operate continuously to maintain voltage levels and relieve system stresses. These activities (called VAR support) are also known as ancillary services.

Finally, because disturbances propagate through the system at essentially the speed of light, extensive protection systems, consisting of automatic switching devices (called relays), must be maintained to ensure a disturbance in one part of the system is isolated automatically. The opening of a switch in response to a disturbance introduces power surges that sometimes set off other switches. Blackouts occur when enough switches open that a resulting electrically isolated (or "islanded"); area cannot meet its loads fast enough with available generation resources, so the remaining generators are automatically isolated to protect them from further damage. The spread of these events can be dramatic, as seen in outages that originated in the Pacific Northwest and ultimately blacked-out much of the West Coast during the summer of 1996.[9]

3.2 Electric Industry Restructuring Issues and Options[10]

Historically, all aspects of power system operation described above were coordinated and maintained by a single entity – the vertically integrated electric utility. Restructuring does not change the need for the physical operations we have described; they remain essential if the electric power system is to operate reliably. Restructuring is, however, an effort to separate or "*unbundle*" these formerly integrated aspects of power system operation and to allow markets to provide them in ways (possibly re-bundled) that are expected to lead to greater economic efficiencies. There are separate functional, physical, and institutional dimensions to this process.

Functional unbundling refers to separating the formerly vertically integrated elements of the utility into separate businesses. Federal Energy Regulatory Commission (FERC) Orders 888 and 889 directed electric utilities to functionally separate their electricity generation business from their electricity transmission and distribution business. FERC's

[9] The causes and implications of these and other recent reliability events are explored in another white paper in this series: "Review of Recent Reliability Issues and System Events" by J. Hauer and J. Dagle.

[10] Emerging efforts to restructure electricity markets are reviewed in greater detail in another white paper in this series: "Review of the Structure of Bulk Power Markets," by B. Kirby and J. Kueck.

objective was to allow increased competition among electricity generation businesses. Functional unbundling means, for example, that decisions to invest in electricity generation facilities are no longer made only by utilities under the scrutiny of utility economic regulators. Instead, these decisions can now be made, in principle, by any investor willing to take on the risks associated with selling a product for which a buyer is no longer guaranteed. Note that functional unbundling does not require physical unbundling (or divestiture) of generation or transmission assets by vertically integrated firms.

"Retail access" refers to another form of functional unbundling in which retail service is separated from distribution. Retail access means that electricity consumers are free to choose their suppliers of electricity; however, they must still rely on a local distribution company to deliver these purchases over existing lines.

Retail access introduces another core concept to the discussion of electricity restructuring: the "obligation to serve." The obligation to serve refers to the traditional responsibility of vertically integrated utilities to plan and operate the electric system reliably in order to meet the needs of all customers. Retail access narrows this responsibility to simply an obligation to connect customers to the grid; customers are now responsible for making arrangements for obtaining (i.e., contracting for) electric service consistent with their willingness and ability to pay.

A basic challenge of utility restructuring is that there is an inherent conflict between the market forces being introduced in the buying and selling of electricity and the interconnected nature of the electric power grid, which means that reliability is fundamentally a common or public good. Balancing the benefit to the public of reliability with the benefit of reliance on competitive forces to organize and operate the future electric system is a central challenge of all current restructuring efforts. Indeed, the most important debates about restructuring involve differences of opinion over the extent to which and the best way to coordinate market-based decision making for procurement and management of the activities identified above that support the complex physical operating requirements of the electric power system.

It is easy to imagine the general form of some of these markets. Forward, bilateral markets for contracts to provide energy already exist for economy exchanges among utilities. Enhancing non-utility parties' access to these contracts was a primary motivation for FERC Orders 888 and 889. Forward markets for many ancillary services are being created. For ancillary services, the products are call options that can be exercised when needed. Spot markets also either already exist or are emerging for energy.

The thorniest issues lie in the details of how these markets are (or should be, in the future) structured and organized: which services (or how many products)? How many markets? If more than one, how are they related to one another? How centralized? How managed or regulated? Who owns transmission assets? Who plans for grid expansion? And, most important of all, who is responsible for ensuring system reliability and how are these responsibilities exercised?

One set of questions regards the number of separate markets that should be created and the nature of the interactions among them. California is an example where forward markets for energy have been separated from forward markets for ancillary services and from spot markets for energy, through the creation of separate scheduling coordinators (including the Power Exchange) and the California Independent System Operator, respectively.

Another set of questions has to do with the degree of centralization in the market's organization. Centralized markets to acquire energy or reliability services typically require strict product definitions and place significant responsibility on a central market operator to ensure transparent and fair operations.[11] Decentralized or bilateral market operations, in which buyers and sellers negotiate directly with each other, can lead to more flexibly defined and potentially innovative (i.e., bundled) commodities; responsibility for ensuring fairness in these transactions is borne largely by the market participants.[12]

As evidenced by California, there can also be an institutional separation between market operation and system operation. That is, markets can lead to agreements among parties to provide energy or reliability services in prespecified amounts or in response to predetermined conditions, according to a schedule. System operation, in turn, may involve no more than the physical execution of these agreements, according to predetermined operating rules.

Another set of questions involves the ownership and operation of transmission facilities. None of the five currently operating independent system operators (ISOs) in the U.S. owns transmission facilities; ownership of these assets remains with the formerly (or currently), vertically integrated utilities while operational control of the assets is assigned to the ISO. Governance (and in particular the degree of an ISO's independence from market participants) is a special concern because, as the monopoly provider of transmission services, an ISO has access to valuable commercial information on market conditions.

Closely related to the question of ownership is the role of profit making (or incentives for efficient operation) and regulation of transmission, both of which are nettlesome issues in most future scenarios. All five existing ISOs are currently organized as non-profit entities, so rate- or performance-based regulation has been less of a concern than governance. In the future, however, regulation issues may assume increased prominence as profit making "Transcos," which would both own and operate transmission assets, are considered.

[11] This is in contrast to the past when these decisions were, in fact, highly centralized because they were made solely by the vertically integrated utility and much less formal product definitions were needed.
[12] Of course, the legal system is available as a forum for dispute resolution.

For all of these questions, responsibility for and enforcement of reliability standards is critical. Today, control area operators are responsible for ensuring reliability standards and operating procedures are met within 140+ electric regions in North America. The standards and procedures they follow have been established on a voluntary basis by 10 regional reliability councils that operate under the auspices of the North American Electric Reliability Council (NERC). These standards and procedures affect decisions made on all the time scales previously identified. More recently, NERC and the regional councils have established 23 security coordinators who are responsible for directing actions that affect very-short-term to near-real-time decisions based on conditions observed across multiple, interconnected control areas.

NERC's standards and procedures were originally developed voluntarily, for the sole purpose of ensuring system reliability. They have been policed in a voluntary fashion by a handful of vertically integrated utilities with regulated earnings (or as public agencies) and few incentives to compete with one another. Today, the transmission system is being operated increasingly to support markets for electricity trade. How reliability standards and procedures will evolve in the future is a key unknown. NERC has recently proposed creation of a mandatory body, called the North American Electric Reliability Organization (NAERO) to permit continued but stronger industry- or self- (rather than government-) regulation of reliability standards in a restructured industry, similar to the industry self-regulation provided by the Securities and Exchange Commission.[13]

[13] "Reliable Power: Renewing the North American Electric Reliability Oversight System." Electric Reliability Panel. North American Electric Reliability Council. December, 1997.

4. Scenario Analysis as a Strategic Tool for RD&D Planning

Scenarios are stories about what the future might look like. They are not predictions. Their value derives from the thinking they inspire on what can or should be done to influence future trends, and how best to go about doing it. This process of "thinking the unthinkable," as it is sometimes called, can, if careful and deliberate, lead to a deeper understanding of key uncertainties and appropriate strategies for addressing them. For example, in our analysis, electric system reliability RD&D activities that emerge as appropriate for any future U.S. electric power system scenario we examine are the ones that are promising to pursue because they are most likely to be robust no matter what future evolves.

Scenario analysis involves postulating internally consistent, alternative futures and analyzing the implications of each alternative in light of a particular planning objective. In this case, the planning objective is the development of an appropriate portfolio of public-interest electric system reliability RD&D. Scenario analysis is a valuable tool for planning; without it, we are left with either planning based on point forecasts of the future or no planning at all, both of which approaches are either wrong and/or irresponsible.

In the following sections, we postulate four scenarios for the future of the U.S. electric power system.[14] Each section is organized as follows: first, we identify driving forces that we believe will tend to influence events toward one scenario versus another. Second, we describe the essential characteristics of each scenario and emphasize the ways in which it differs from the other scenarios. Third, we outline basic RD&D needs associated with each scenario. Fourth, we examine the rationale for federal support in meeting these needs.

Because scenario characteristics are influenced by driving forces and these forces are inherently uncertain; we consider the influence of uncertainties on each scenario. Section nine identifies four key uncertainties and evaluates our findings in light of them.

[14] The original inspiration for the scenarios is "Underlying Technical Issues in Electricity Deregulation," which was prepared by R. Thomas and T. Schneider as a summary of a collaborative writing exercise involving the Power Systems Engineering Research Center and the Electric Power Research Institute. A summary of these discussions was published in the "Proceedings of the Hawaii International Conference on System Sciences." Institute of Electrical and Electronic Engineers. 1998.

5. Scenario 1: An Industry in Transition

The first scenario is a starting point for development of the three scenarios that follow. It for the most part reflects the state of the U.S. power system following FERC orders 888 and 889. We also believe it to some extent reflects the events that will unfold in some parts of the U.S. power system during the next three to five years. We have, however, exaggerated some aspects of today's situation in order to dramatize certain findings. Therefore, this scenario should not be confused with a prediction of how we believe events will or should unfold.

5.1 Key Driving Forces

We believe the following conditions (or phenomena) will tend to influence the evolution of the U.S. power system toward this scenario:

Large economic gains from electricity trade create significant demands for bulk transmission services.

Ambiguous findings from public health studies and popular environmental concerns fuel strong public opposition to construction of new transmission facilities.

Failure to completely resolve the problem of stranded assets continues to stall progress toward open markets and regional solutions.

Public confidence in and support for restructuring wanes among stakeholders that cannot enjoy or have been precluded from enjoying real economic gains and who may even suffer losses.

State authorities dig in and challenge FERC directives; some stakeholders successfully lobby to water down federal legislation.

5.2 Scenario 1 Description

In scenario 1, there is minimum structural compliance with FERC orders 888 and 889. Vertically integrated utilities functionally unbundle transmission and power sales functions but continue to own transmission facilities and operate control areas. Transmission system functions and staff are separated from wholesale generation marketing and its staff. Standards of conduct define appropriate and inappropriate interactions between the two staffs. Transmission services are taken by the utility under the same open access tariffs available to other market participants. Separate rates are posted for wholesale generation, transmission, and six ancillary services. Available Transfer Capability (ATC) and transmission prices are posted on the Open Access, Same-Time Information System (OASIS).

Market operations are limited to wholesale electricity trade conducted on a bilateral basis between buyers and sellers. There is limited or no retail access; for the most part, vertically integrated utilities continue to perform economic dispatch to serve franchise customers. Posted transmission prices and ATC are based on internal calculations by transmission owner/operators. For example, Capacity Benefit Margins (which reduce ATC) are set by transmission owner/operators using methods that are not uniform, nor subject to audit.

Existing regional system operation (current control area boundaries) remains unchanged, leading to myopic and potentially inaccurate ATC calculations, pancaking of transmission access charges, and continual disputes over compensation for loop flow.

Investment in grid expansion is hampered by lack of clear incentives or uncertainty about incentives for potential investors and by the absence of regional decision making bodies with either incentive or authority to direct grid expansion. In addition, FERC authorizes lower rates of return for transmission investments than those traditionally authorized by state authorities, further dampening investment.

In other words, there are no inherent incentives for vertically integrated firms to actively support development of wholesale competition (except for that which benefits them directly). Moreover, firms that are saddled with strandable assets or concerned about threats to continuation of the retail monopoly franchise have extremely powerful incentives to thwart new entrants. Traditional incentives for transmission system investment, including rate-of-return regulation and lower production cost through access to cheaper sources of supply, will not be strong enough to spur adequate investment, given the threat of new entrants to the market.

Reliability management remains a primary responsibility of control area operators. However, their limited regional scope leaves them without strong incentives for initiating actions based on a system-wide perspective. Security coordinators play a vital and increasingly demanding role in ensuring adequate coordination among control areas. Congestion management relies on NERC's Transmission Relief Protocols, which are controversial and protested by some market participants who feel subject to gaming.

Transformation of NERC to the North American Electric Reliability Organization is incomplete. Newer market entrants feel excluded. Dispute resolution occurs in slow, costly, and time-consuming legal processes. Because of the time required for resolution, market participants are reluctant to bring suits for fear of retribution in the marketplace while legal challenges drag on.

The institutional capabilities of organizations that have traditionally played a major role in reliability management degrade as uncertainties in the utility business environment lead to dramatic staffing cuts. Deferred maintenance back-logs accumulate. The reliability of the bulk power system is compromised, leading to increasingly frequent outages and near misses. The public, aided by parochial interests becomes concerned that restructuring is too costly an experiment for this essential industry.

5.3 System Reliability RD&D Needs

The system reliability RD&D needs that emerge from this scenario are grounded in familiar power system planning and operational activities. All traditional elements of modern power system planning and operation remain important. However, the emphasis of these activities shifts from its historic focus, in which power exchange maintains and enhances system reliability, to one that seeks to increase the system's capability to support electricity trade for economic purposes. There are now powerful economic incentives to fully utilize existing transmission assets and operate the power system closer to its physical limits rather than continue to operate with large safety margins; in other words, traditional incentives to maintain system reliability are severely tested. New technologies and tools as well as new approaches to using existing technologies and tools are required. RD&D is appropriate in the broad areas of: 1) enabling technologies to increase the capability to transmit power; and 2) sensing, communication, computation, and control technologies for better utilization of transmission assets.

In the area of enabling technologies, we include the following activities that increase the ability of the system to transmit power:

1. Flexible alternating current transmission systems (or FACTS) devices, which allow operators to manage and control power flows actively rather than responding to these flows passively. Reducing the costs of these technologies and developing sophisticated tools to utilize them is a high priority to increase the controllability of the grid, which will, in turn, allow for increased power flows and enhanced reliability.
2. Underground high-capacity transmission technologies to circumvent public opposition to construction of aboveground transmission lines.
3. High-temperature superconducting wires to dramatically increase the carrying capacity of lines.

In the area of sensing, communication, computation, and control technologies, we include technologies and tools that enhance power flow management and support the planning and operational needs of control area operators and security coordinators.[15]

In the area of operational and planning tools, RD&D needs include improvements in:

1. load forecasting,
2. maintenance scheduling,
3. unit commitment,
4. system monitoring,
5. state estimation,
6. optimal power flow,
7. contingency analysis,

[15] Aspects of the RD&D needs that are identified in this subsection are developed more fully in three white papers: "Review of Recent Reliability Issues and System Events," by J. Hauer and J. Dagle; "Accommodating Uncertainty in Planning and Operations," by M. Ivey, A. Akhil, D. Robinson, J. Stamp, K. Stamber, and K. Chu; "Real Time Security Monitoring and Control of Power Systems," by G. Gross, A. Bose, C. Demarco, M. Pai, J. Thorp, and P. Varaiya.

8. steady-state security assessment,
9. dynamic security assessment,
10. available transfer capability (ATC), and
11. transmission planning.

The latter two types of tools will prove especially important in this scenario because they represent points of interface between the vertically integrated firm and the market to which the firm is now charged with providing non-discriminatory access. However, the important issues will tend to be less technical and more procedural and enforcement related. What assumptions are made in ATC calculation and determination of transmission prices? What objective function is being maximized in transmission planning? And what are the impacts of proposed solutions on different market participants? Unfortunately, without NAERO, the only venue where these questions can be aired formally will be in courts of law.

A particularly important new user of tools for reliability management in this scenario is the security coordinator. In view of the economic incentives that control area operators have to maximize the benefits from trade as well as the limited formal scope of their authority, security coordinators alone now have the unique responsibility to take a system-wide perspective to ensure reliability. Tools that enhance their ability to rapidly and accurately estimate the state of the system as a whole, that increase their ability to control/manage flows on the system, and that allow them to take action confidently (or that allow for robust automatic responses) are especially needed.

Technologies and tools are needed to improve system measurement, communication, and computational procedures. Time-synchronized phasor measurements collected over large geographic areas, coupled with high-speed communication, improved algorithms, and computational technology (e.g., the Wide Area Measurement System or WAMS) can produce a much more precise estimate of the state of the system than is currently possible. These technologies will also allow improved estimates of system reliability and opportunities for trade.

Improved methods are needed for accommodating and making decisions that take into account uncertainty because recognition is growing that traditional approaches (e.g., "N-1" planning criteria) are insufficient. Sequences of outages and correlations among initiating events must be accounted for. More importantly, better quantification of underlying risk factors (e.g., the cost and frequency of various contingencies) is required so that economic trade-offs can be made. For example, a risk-based, cost-minimizing method is needed to optimize maintenance scheduling for existing transmission assets.

Associated with the need to use better data and better decision making approaches is the need to ensure that operators and security coordinators can take full advantage of them. This requires tools for data summary and visualization on the one hand and ongoing training on the other.

5.4 Rationale for Federal RD&D

If scenario 1 were a stable end state, a minimalist federal role in electric system reliability RD&D would be justified. Basic RD&D advances in computation, communication, risk management/decision analysis, and data visualization are likely to continue to come primarily from outside the electric power industry. Moreover, in a stable environment, traditional incentives for RD&D investments would lead naturally to applications and healthy markets for advanced technologies and tools that support power system reliability. In such a state, federal RD&D would continue its historic role of supporting very long-term, fundamental research in basic materials and advanced concepts that enables or complements these private-sector activities.

However, in this scenario, the electric power industry is in transition, so time horizons for private investment are shortened, and risks to private investors are increased. Nevertheless, reliability remains a critical public good. In this transition state, there are few incentives for the private sector to undertake electric system reliability RD&D except in areas where results are short term and guarantee competitive advantage.

As far as future evolution of the system is concerned, we find an absence of incentives for investments in RD&D to increase the system's capability to support new entrants. Incumbents have limited interest in encouraging greater competition, and new entrants are at a disadvantage because they are not privy to the detailed workings of the system in which they have to operate.

Most important, there are few, if any, incentives for investments based on the system-wide perspective that is the defining characteristic of the interconnected U.S. electric power network. The need for these investments is especially great as demands to support increased trade place significant and dangerous new pressures on an aging power system.

6. Scenario 2: Large, Centralized, Regional Transmission Organizations

We offer scenario 2 as the first of two scenarios that describe more or less opposite institutional end states for the industry. Scenario 2 takes to an extreme views espoused by proponents of centralization in the electricity industry. Scenarios 2 and 3 both draw from the recent FERC notice of proposed rulemaking (NOPR) on Regional Transmission Organizations (RTOs). [16] This scenario, like the others, is not offered as a prediction of the future but as an exercise to examine the RD&D implications of one possible future state of the electricity industry.

6.1 Key Driving Forces

Two critical driving forces for scenario 2 are consistent with those identified in scenario 1:

There are significant economies from expanded electricity trading within large geographic regions.

Ambiguous findings from public health studies and popular environmental concerns fuel strong public opposition to construction of new transmission facilities.

Several additional driving forces distinguish this scenario from scenario 1:

Wealth created by trade leads to mutually agreed-upon sharing formulas that facilitate rapid working off of stranded assets.

Federal and regional leadership is unified, strong, and powerful; state and corporate entities are comparatively weaker in political terms (and less vocal in part because they no longer have stranded assets to protect).

Centralized market-operating bodies are perceived to perform in a competent, transparent, and fair manner that circumvents gaming by market participants

Integrated and centralized approaches are perceived to be efficient because they lower transaction costs that would otherwise be higher for parties contracting in less centralized market settings.

6.2 Scenario 2 Description

In this scenario, new entities, called Regional Transmission Organizations (RTOs), emerge to satisfy all four characteristics and provide all seven functions outlined in FERC's recent NOPR. We postulate extreme centralization and coordination of markets

[16] "Regional Transmission Organizations, Notice of Proposed Rulemaking." U.S. Federal Energy Regulatory Commission. May 12, 1999.

by RTOs, both for the energy trading and for the RTOs' procurement of reliability services (formal organization of these elements of RTO functions were left open by the NOPR).

RTOs are structured as for-profit entities that are not controlled by market participants; this is in contrast to the non-profit status of today's ISOs. The regions controlled by a single RTO are large, typically encompassing more than one existing control area (possibly, through a master/satellite arrangement) and affecting operations in more than one state. Most importantly, the RTO operates all transmission facilities within a given region. The RTO is the designated security coordinator for the transmission facilities that it controls. It has exclusive authority for maintaining short-term reliability.

The RTO performs all of the necessary functions identified in the FERC NOPR as well as others. That is, the RTO: a) provides non-discriminatory access to transmission services for all market participants; b) develops and operates market mechanisms to manage congestion; c) addresses parallel flow; d) is supplier of last resort for ancillary services; e) is the single OASIS site, which independently calculates total transfer capability and ATC; f) monitors the market; and g) plans transmission.

In addition, the RTO also operates integrated forward and spot markets for energy, as well as markets to procure reliability or ancillary services (while respecting market participants' rights to provide some services themselves). The RTO contracts for call options to provide certain reliability services that cannot be procured effectively in spot markets using the competitive solicitations that it also manages.

A defining feature of the market mechanisms employed by the RTO is their formal organization and centralized management. For example, based on information from the forward markets, the RTO performs and then makes available information from a globally optimized unit commitment that it then uses to schedule the dispatch of generators and to set nodal transmission prices.

Finally, the RTO also owns all transmission assets and is solely responsible for transmission planning and investment.

In this scenario, ultimate responsibility for maintaining system security rests firmly with the RTO. The RTO is the provider of last resort for ancillary services (principally through call options on generators and loads). The RTO also retains ultimate authority to order re-dispatch in response to contingencies. As required by FERC and noted above, the RTO is the NERC security coordinator.

A key challenge in this scenario lies in the incentives provided to the RTO for efficient operation. Due to the for-profit status postulated above, these incentives are provided primarily in the form of performance-based, regulatory incentives. One the one hand, the RTO as final guarantor of reliability should have incentives to ensure reliability cost effectively. On the other hand, the RTO as market manager should also have incentives to maximize efficient trade. To the extent that these objectives conflict, appropriate trade-offs will have to be made in the system of incentives offered to the RTO.

6.3 System Reliability RD&D Needs

System reliability RD&D needs for this scenario build on the RD&D needs identified in scenario 1. In particular, RD&D in tools and technologies that enhance transmission capacity and controllability of power flows remains an important focus. However, creation of RTOs with such broad geographic reach places greater emphasis on several RD&D needs, and operation of centralized markets creates RD&D needs that are unique to this scenario.[17]

The greatly increased size of the RTOs considered in this scenario places increased emphasis on the following RD&D needs that were identified for scenario 1:

1. Advanced monitoring technologies to collect, process, and share data over large geographic areas (e.g., WAMS);
2. Better, faster algorithms and more powerful computational platforms for solving traditional power system problems; these problems include state estimation, security-constrained optimal power flow, and integrated optimal power flow and unit commitment.
3. More powerful methods for efficiently evaluating a greater number of possible contingencies, including new approaches that consider multiple and correlated contingencies.

The desire to support enhanced trade and using a single, integrated institutional market structure creates RD&D needs unique to this scenario:

1. Examination of planning and operating contingencies resulting from market operations and the behavior of market participants in addition to and in conjunction with contingencies resulting from physical phenomena.
2. Reevaluation of system protection philosophies (as well as maintenance practices/scheduling). Currently, system protection philosophies are designed to ensure that a fault never fails to clear. This philosophy leads to false tripping and contributes directly to cascading outages. Examining the economic trade-offs implied by continued reliance on these philosophies is a first step toward rationalizing reliability needs with market demands.
3. Definition, quantification, cost calculation, monitoring, and verification of ancillary services.

[17] Aspects of the RD&D needs that are identified in this subsection are developed more fully in other white papers: "Review of the Structure of Bulk Power Markets," by B. Kirby and J. Kueck; "Accommodating Uncertainty in Planning and Operations," by M. Ivey, A. Akhil, D. Robinson, J. Stamp, K. Stamber, and K. Chu; "Real Time Security Monitoring and Control of Power Systems," by G. Gross, A. Bose, C. Demarco, M. Pai, J. Thorp, and P. Varaiya.

In addition, reliance on centralized market mechanisms to acquire many system reliability services creates new RD&D needs, including:

1. Design and operation of efficient and coordinated centralized markets (e.g., settlement procedures); integral to this research is development of performance metrics for assessing the efficiency with which the RTO operates these markets (this will provide a basis for incentives to the RTO for superior performance);
2. Creation of market interface technologies (i.e., communication) to enable broad participation and assure secure operations;
3. Development of costing methodologies for services that must be provided centrally, in particular assignment of losses within the transmission system; and
4. Development of transmission planning tools that incorporate the impacts of investment alternatives on different market participants.

The design of appropriate incentives for efficient RTO behavior is an important RD&D challenge by itself. In addition, the previously identified tools and technologies will have to be used in a transparent fashion so the RTO can be accountable to market participants. Because the RTO is responsible for both market operation and system reliability, there will be a particular need to document and justify the inevitable trade-offs that will be made in carrying out these responsibilities.

6.4 Rationale for Federal RD&D

We are guardedly optimistic that the RTOs and the supporting industry that we postulate can be designed with appropriate incentives to invest in necessary, ongoing shorter-term RD&D for electric system reliability. The federal government will, however, still have a role in monitoring these activities and supporting and complementing them with longer-range ones. Federal investments will be needed for RD&D to enhance transfer capability and reliability, as described in scenario 1, and RD&D for the market-enabling tools and technologies identified in section 6.3.

In order to reach steady state, however, federal investments are needed to support the creation of appropriate institutional structures and systems of incentives to ensure that robust organizations to administer electric system reliability activities are put in place. The ultimate form of incentives needed to create a stable industry is not yet known. A variety of important developments are currently taking place around the country; scenario 2 scenario has postulated one extreme vision of where these developments might lead. However, in our opinion, none of these developments yet represents a completely stable environment in which we can determine whether current incentives for RD&D investment will be adequate. Notably, the newest ISOs are focussed on start up issues and on addressing only the most critical situations. To our knowledge, none has presented a fully developed, multi-year plan for RD&D.

Federal support for RD&D is especially important as these developments around the country proceed because no private party is in a position to pursue the research. Individual private sector market participants stand to profit from the outcome of these developments and are therefore not in a position to evaluate them from a neutral perspective. Nor are these parties in a position to identify and report on all the appropriate measures by which these developments should be judged. The federal role is to support thorough, unbiased evaluations of the merits of various institutions to administer electric power system reliability.

Because it will take some time to settle these institutional issues, gaps in technology RD&D are likely to develop, as in scenario 1, unless the federal government supports this research. In the industry's current transition state, there is a compelling argument for federal RD&D to maintain adequate levels of investment in electric system reliability RD&D until stable institutional structures for supporting RD&D emerge. This transition-period RD&D should be consistent with the move toward greater reliance on market mechanisms to organize planning and operational decision making.

7. Scenario 3: Maximally *Decentralized* Regional Transmission Organizations

Scenario 3 is an alternative vision to that offered in scenario 2. Where scenario 2 proposed an extremely centralized set of institutions for electric system reliability, scenario 3 envisions a future where decision making and market operations are extremely decentralized. As with the previous scenario, we draw from the recent FERC Notice of Proposed Rulemaking (NOPR) on RTOs. This scenario, like the others, is not a prediction of the future but an exercise to examine the implications of a highly stylized characterization of what the future electricity industry might look like if the proponents of decentralization in today's industry prevail.

7.1 Key Driving Forces

Scenario 3 assumes the following driving forces from the first two scenarios:

Large economic gains from electricity trade create significant demands for bulk transmission services.

Ambiguous findings from public health studies and popular environmental concerns fuel strong public opposition to construction of new transmission facilities.

Scenario 3 also shares an important driving force from the scenario 2, that the significant economic gains from electricity trade make politically acceptable the wealth sharing necessary to permit an equitable and quick elimination of stranded assets.

However, in contrast to the scenario 2, scenario 3 posits that parochial concerns (e.g., state's rights) and mistrust of centralized planning approaches mean that no party is willing to accept a centralized market operator as one that is sufficiently impartial and benevolent. Optimal operations sought by centralized market operators are perceived as too elusive (or not offering substantial advantages over other approaches to system management). Some believe it is more politically appropriate to distribute responsibility for market outcomes to self-interested market participants (the "invisible hand"). Others argue that centralized solutions stifle innovation and disagree with the doctrine that short-term economic efficiencies lead naturally to longer-term efficiencies.

7.2 Scenario 3 Description

Scenario 3, although it too is based on the RTO characteristics and functions described in FERC's NOPR, is offered as a sharp contrast to scenario 2, which envisioned centralized market organization and operation. Scenario 2 combined two design objectives, welfare maximization and maintenance of system reliability through centralized market operation. Scenario 3, in contrast, takes a minimalist approach that seeks to reduce or eliminate the need for centralized coordination wherever possible, consistent with agreed-upon performance standards. The RTO in this scenario focuses solely on maintaining system reliability.

A major point of departure from scenario 2 is that the RTO in this scenario has limited or no responsibility for organizing or operating markets for electricity trade. Its primary job is to execute orders for trade, monitor the state of the system, and provide information to market participants on system conditions so that their trade decisions can be consistent with what the system can reliably accommodate. Market participants must negotiate decisions among themselves, however. In other words, the RTO in this scenario turns to markets to obtain *services*, whereas the RTO in the previous scenario turns to markets to obtain *resources*, which the RTO then selects from to create the services it needs.

The primary objective of the RTO in scenario 3 is to maintain short-term system reliability. There are, of course, limits to the ability of decentralized markets to self-organize and self-sustain themselves to support near-real-time and real-time operations. Thus, the RTO must be ready to intervene physically as a last resort when markets fail to respond adequately to contingencies or emergency situations.

A key feature of the RTO design philosophy is that reliability decision making is devoid of economic considerations. There is an inevitable tension between impartially established operating rules and economic efficiency. For example, in response to an emergency, the RTO would call for control actions according to well-defined rules. However, the resources it would call upon to respond to the emergency would likely have been procured ahead of time through competitive solicitations. Similarly, in order to manage congestion on the grid, the RTO would need to invoke protocols that would have economic implications for affected parties. (This example assumes that private markets to manage congestion fail to respond to the need for relief in the system, and that a separate institution, which would be distinct from the RTO, is not organized to manage the situation). We assume that economic implications will not be considered (at least, not in real time when actions are taken) when emergencies and contingencies are handled according to agreed-upon protocols.

Consistent with the minimalist philosophy, the RTO in this scenario does not own or engage in planning for transmission assets. The RTO's sole responsibility is to provide unbiased information on system conditions, so market participants can make (and take full responsibility for the consequences of) transmission planning decisions. A key unresolved question is what remaining public interests are served by transmission investment and what mechanisms must be developed to ensure transmission investments are made consistent with this interest. Siting of transmission facilities will still require government authorization.

The geographic scope served by the RTO is another important unresolved issue in scenario 3. In an idealized setting, the only limits on RTO size would be the market size necessary to support efficient and self-sustaining trade among participants. The minimum RTO could, in principle, accommodate several, smaller private pools that would self- or independently organize centralized trade on behalf of some groups of market participants, while at the same time, accommodating bilateral trade among other groups of participants.

We envision the RTO as a for-profit entity. Its compensation is tied to how well it supports market operations with a minimum of intervention, as well as, how well it responds to contingencies that cannot be addressed effectively by independently organized markets.

7.3 System Reliability RD&D Needs

System reliability RD&D needs in scenario 2 were framed in the context of the RTO's RD&D needs. In scenario 3, many of these needs remain, in particular those that enhance the power grid's transfer capability. However, in scenario 3, market participants, not just the RTO, will need to use many of these same transfer-capability assessment tools and technologies, so the scale of the problems to which these tools and technologies will be applied may change.[18]

For example, the RTO will not be responsible for unit commitment; market participants will bargain among themselves and submit schedules to the RTO. Development of these schedules may involve unit commitment decisions made by or on behalf of market participants. As noted, the design philosophy underlying this scenario is consistent with the emergence of multiple, private, centralized pooling arrangements within the RTO. Similarly, while the RTO may use transmission planning tools to provide information to market participants that are considering constructing transmission lines, the parties that assume or are charged with responsibility for building transmission lines will also need to use these tools.

The RTO retains ultimate responsibility for system security, so all the tools identified in earlier scenarios for this purpose are relevant in scenario 3. Depending on the RTO's geographical scope, the measurement, communication, and computational requirements of these tools may be similar to those in scenario 2.

A key difference from scenarios 1 and 2 is that scenario 3 relies on the market to provide many reliability services. Accordingly, a core responsibility of the RTO in this scenario is to convey information on system conditions efficiently and accurately for several time horizons, in order to guide market participants toward feasible solutions. This information might range from a solved power flow in the very short term to information conveyed in real time following system disturbances (e.g., frequency).

[18] Aspects of the RD&D needs that are identified in this subsection are developed more fully in other white papers: "Review of the Structure of Bulk Power Markets," by B. Kirby and J. Kueck; "Accommodating Uncertainty in Planning and Operations," by M. Ivey, A. Akhil, D. Robinson, J. Stamp, K. Stamber, and K. Chu; "Real Time Security Monitoring and Control of Power Systems," by G. Gross, A. Bose, C. Demarco, M. Pai, J. Thorp, and P. Varaiya.

The need for timely and accurate information means the RTO needs computational and communication techniques and technologies that meet stringent requirements. RD&D will be essential to support information management between the RTO and the market.

Because the RTO will have even less information than the RTO of scenario 2 on which of the many feasible market outcomes is most likely, analysis of uncertainty will be extremely important. Uncertainties in this scenario derive not only from unpredictable physical events but also from unpredictable market events. The need for uncertainty analysis goes hand in hand with the need for market monitoring and performance verification systems.

Market participants will also need market financial risk management and forecasting tools and techniques that can account for the unique features of electrical networks and power system operation. Systems (e.g., scheduling tools) will also be necessary to support development and operation of innovative private markets.

7.4 Rationale for Federal RD&D

The rationale for federal RD&D in this scenario is similar to that for the scenario 2 although, as noted, the focus of RD&D consciously shifts from the needs of only the RTO to the needs of both the RTO and the market participants. As with scenario 2, we continue to believe that the RTO and the supporting industry that we postulate will emerge can be designed with appropriate incentives to invest in necessary, ongoing shorter-term RD&D for electric system reliability. The federal government will, however, still have a role in monitoring these activities and supporting and complementing them with longer-range investments. We expect that these investments will focus both on RD&D to support reliability and transfer capability as described in scenario 1 and also on aspects of the market-enabling tools and technologies identified above for scenario 3.

However, as in scenario 2, we see a near-term need for federal investments in electric system reliability RD&D to support the creation of robust institutional structures and systems of incentives. Scenarios 2 and 3 illustrate two fundamentally different forms that a future stable electricity industry could take, both of which we hypothesize will include adequate incentives for investments in electric system reliability RD&D. Federal RD&D investments to evaluate emerging alternatives will be essential for the development of robust structures.

Elements of all 3 scenarios are currently being tested around the country. Federal support for monitoring and analysis of these developments is needed because no single, private party is in a position to pursue the necessary research or to undertake it in an unbiased fashion, given its ultimate commercial implications.

Because it will take some time to settle institutional issues, gaps in technology RD&D are likely to develop. Hence, consistent with scenario 2, there is a compelling argument for federal RD&D to maintain adequate levels of investment in electric system reliability RD&D during this period of industry transition. This RD&D should be sustained until more stable structures for supporting RD&D emerge and should be consistent with restructuring's movement toward greater reliance on market mechanisms for planning and operation decisions.

8. Scenario 4: Distributed or Dispersed Energy Resources

Up to this point, the scenarios we have considered have focused on organizational and structural alternatives for operation of the high-voltage or bulk power system. In scenario 4, which could be compatible with any one of the first three scenarios, we attempt 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.

8.1 Key Driving Forces

Driving forces in scenario 4 are:

Greatly reduced capital costs and higher operating efficiencies for smaller-scale generating sources. To some extent, these are driven by developments in the automotive and defense industries (e.g., fuel cells and microturbines).

Low natural gas prices; natural gas is a primary source of fuel for many smaller-scale generating sources.

Similar to the earlier scenarios, ambiguous findings from public health studies and popular environmental concerns fuel strong public opposition to construction of new transmission facilities. In the context of this scenario, resulting increased transmission constraints lead to higher local prices for electricity.

Increased customer demand for reliable sources of power (e.g., uninterrupted power systems) and/or higher quality sources of power (e.g., custom power devices). On the supply-side, reduced power system reliability and poor power quality will also fuel these demands.

Changes in distribution company organization (divestiture from generation-owning and, possibly, transmission-owning "parents") and changes in state regulatory practices (e.g., fuel adjustment clauses and infrequent rate cases, or price caps), which currently provides strong financial incentives to discourage losses of sales (i.e., revenues).

New, integrated energy services providers seeking to market new, innovative bundles of energy-related commodities, capital goods, and services.

8.2 Scenario 4 Description

Scenario 4 envisions greatly increased market penetration by distributed or dispersed energy resources relative to what is observed today. The size of the resource, the fuel source on which it relies, or the service it provides (which could be, for example, storage or load management rather than electricity generation), is secondary in importance to the issues raised by the addition of significant numbers of these technologies to the distribution system.

We postulate substantial increased reliance on these technologies to the point where, in selective areas seven to 10 years from now, generation from these sources accounts for 20% or more of new generation. There are important parallels between the physical, decision making, and market implications of such a development and the emergence of the personal computer 20 years ago.

In physical terms, this scenario presents a dramatic alternative to conventional wisdom regarding the operation of the low-voltage, distribution power system. Nevertheless, this scenario assumes that the high-voltage bulk power system remains a major source of electricity (although we consider instances of islanded operation at various time scales).

In terms of decision making, decisions about investment in this scenario are driven by demand-side market participants, which is in sharp contrast to the previous scenarios in which investment is driven by system or supply-side market participants. We assume, for example, that state regulatory authorities limit investment in small-scale generation sources by distribution companies because it tends to violate the functional separation between generation and distribution that is a fundamental tenet of restructuring. As noted, we also assume, as a driving force, that regulation of distribution companies makes them financially indifferent to losses of load to small-scale customer- or privately owned generators.

From a market perspective, new business models evolve to support decisions by individuals or formally organized or externally aggregated groups of power consumers about whether to invest in, lease, or purchase electricity from small-scale, non-utility generation sources. Some customers/groups choose to leave the grid entirely. Others rely on the grid to supply residual demands and as a backup source of power. Still others operate in a dual mode, in which they can automatically separate and undertake islanded operation in response to bulk power system disturbances with automatic resynchronization at a future time when the bulk power system is stable again.

Responsibility and incentives to ensure reliability in this scenario are fundamentally different than in the other scenarios. Rather than being borne exclusively by the utility system, the responsibility for reliability is now essentially borne by the customer. Customer choice in selecting and paying for reliability through private investments in these distributed or dispersed technologies brings restructuring full circle; reliability, in this scenario, is truly a market commodity.

8.3 System Reliability RD&D Needs

The reliability RD&D needs in this scenario are perhaps the most fundamental of all four scenarios, because they involve reconfiguring the distribution system from supporting the one-way flow of electricity from generators to customers to supporting two-way flows among sites located throughout the distribution system.[19]

Distribution system protection philosophies (and associated relaying and breaker specifications) must be re-examined and modified to accommodate injections of power along or at the ends of radial lines.

There is also a need for new methods to assess the effects of large numbers of distributed technologies (e.g., storage) on local area and system reliability. Conventional transmission planning models treat the entire distribution system as individual loads at substation buses, while distribution system planning models treat the transmission network as a voltage source at the each substation low-voltage bus. Transmission models are based on the assumption of an interconnected network in which all voltages, loads, and impedances are balanced. The best distribution models explicitly address imbalances, including single-phase loads, but do not allow for interconnection between circuits or adjacent substation areas. In order to assess the impact of large numbers of distributed resources on the dynamics of a regional electric grid as well as on local service conditions during a disturbance, it will be necessary to develop methods that treat the distribution system with the transmission network in a consistent (if not integrated) fashion.

To support the use of these models, better information than is currently available on the performance characteristics of inertia-less, distributed generation resources must be developed. Many distributed technologies are fundamentally different from conventional central-station generation technologies. For instance, fuel cells and battery storage devices have no moving parts and are linked to the system through electronic interfaces. Microturbines have extremely lightweight moving parts and also use electronic system interfaces. The dynamic performance of such inertia-less devices cannot be modeled simply as if they were scaled down central-station units. Other issues, such as permissible ramp rates and reactive power capability, must also be determined so their behavior can be modeled accurately. Information on these kinds of performance characteristics is beginning to emerge from laboratory test facilities but additional testing may be needed to fully characterize their impacts on distribution system reliability. Once is information is obtained, performance models for individual technologies must be developed that can be incorporated into system simulation models.

New technologies and control and communication strategies are needed to manage locally the operation of distributed technologies (e.g., load tracking and load sharing) in a distribution system that contains large numbers of these technologies, including operation in either satellite or island modes. Decentralized dispatch methods must be explored as it

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[19] Aspects of the RD&D needs that are identified in this subsection are developed more fully in the white paper: "Interconnection and Controls for Reliable, Large Scale Integration of Distributed Energy Resources" by V. Budhraja, C. Martinez, J. Dyer, and M. Kondragunta.

is unlikely that formal dispatch of hundreds or even thousands of very small sources can be effectively coordinated through centralized approaches.

The cost of electronic interfaces to the distribution system must be lowered and their quality improved. Most advanced distributed resource options (fuel cells, storage devices, microturbines) require power electronic inverters to interface with the power system, and the dynamic performance of the distributed resource is largely determined by the characteristics of the interface. In many cases, the cost of currently available power electronic interfaces rivals the cost of the generating or storage technology itself, and the performance characteristics of interfaces are rarely, if ever, optimized. This compromised performance is the result of using of modified commercial units designed originally for other purposes. Advanced inverter topologies are needed that can be easily cost- and performance-optimized by manufacturers for the specific requirements of distributed technologies. Better definition of required performance characteristics is also needed to ensure the design of desirable dynamic responses. Considerable work is under way to support transportation and other high-volume applications of power electronics. Large-scale procurement of this technology by other industries may well bring costs down so that it can form the basis for a new generation of advanced distributed technology inverters with characteristics that can be tailored to specific needs.

Power electronic interfaces are not only a key enabling technology for distributed technologies; these interfaces could also be used as custom power devices to enhance customer power quality, which is an advantage that, if publicized, should increase consumer interest in distributed generation technologies.

New methods and technologies are needed to enhance demand-side response (i.e., price elasticity).[20] Recent studies also suggest that increasing demand-side response is an effective way to for mitigate supply-side market power in generation markets. However, there has been limited appreciation of the role of demand-side resources, outside of load management and time-of-use pricing, in enhancing system reliability. Some of the reasons are regulatory -- customers cannot yet see a price for reliability services. However, some of the reasons are technological -- the ability of demand-side resources to provide reliability services has not yet been explored. Research is needed to better understand short-time interval load characteristics and the possibility of using of demand-side resources in order to determine to what extent these resources can be relied on to enhance system reliability.

8.4 Rationale for Federal RD&D

As noted above, the electric system reliability RD&D needs associated with this scenario are perhaps more significant and fundamental than those called for in the previous three scenarios because they entail a radical re-examination of the basic tenets of distribution system planning and operation. Federal support for this RD&D is necessary because of

[20] Aspects of this RD&D issue are developed more fully in another white paper: "Review of the Structure of Bulk Power Markets," by B. Kirby and J. Kueck.

the basic nature of the research required and the current disincentives to private parties to support it. Without federal support, the market will be slow to capture the environmental and reliability benefits promised by dispersed or distributed technologies.

The fundamental nature of this RD&D required means that payoffs will be long term and uncertain because some aspects of reliability will remain public goods that will be hard for individual parties to capture fully. These traditional principles for federal involvement are especially strong in view of the additional disincentives for investment faced by market participants during this period of transition in the electric power industry.

Those with the greatest potential interest in (and capacity to support) needed RD&D investments, electric distribution companies, currently face unclear and/or negative incentives to undertake these investments on their own. The industry's current transitional state provides limited incentives for only a very narrow range of investments. More importantly, current regulatory practices provide powerful incentives to distribution companies to actively discourage customer adoption of these dispersed or distributed technologies because they reduce sales.

Thus, there is a critical need for public-interest RD&D to overcome the huge informational advantages that distribution utilities have in assessing the system-wide benefits (and costs) of increased penetration of smaller scale sources of generation. Those who have the incentive to pursue this research, private developers and customers, will not otherwise be able to obtain the information needed to determine these benefits and develop the technologies independently.

9. Key Uncertainties for the Scenarios

For each of the four scenarios, we have identified key driving forces that tend to support movement toward one scenario versus the others (although, as noted, the fourth scenario could co-exist compatibly with all of the others). In this section, we consider the effects of additional driving forces that were not considered explicitly in the development of the scenarios. These additional driving forces will likely tip the balance toward one scenario versus another. They might also shape but not fundamentally change elements within the scenarios.

We address these potential, additional driving forces because they represent large, unaccounted-for macro-uncertainties that cut across all of the scenarios. The analysis in this section, is, in other words, a reality check for our preliminary findings.

A complete examination of uncertainty is beyond the scope of this paper, so we separately consider four key uncertainties that we believe are especially significant for the scenarios:
1. A global treaty limiting emissions of greenhouse gases;
2. Greatly increased growth in the demand for electricity services;
3. Dramatic consolidation among market participants; and
4. Malicious cyber attacks on communication and computer networks on which power system operations rely.

9.1 Greenhouse Gas Emission Limitations

Limitations on emissions of greenhouse gases would mean a shift from reliance on fossil fuels for electricity production to non-fossil fuels (renewable energy and perhaps nuclear although the likelihood of changes in public acceptance of nuclear power is another critical unknown) and to an emphasis on energy efficiency. Both central-station and smaller scale power plants that burn fossil fuels would be affected. Coal-fired power plants would be affected more than gas-fired ones. There are significant differences of opinion on the magnitude of the macroeconomic effects of these limitations on electricity demand, aside from pressure to increase end-use energy efficiency.

In the short run, greenhouse gas emissions restrictions would tend to increase the price of fossil-fueled electric generation relative to other sources. Changes in the price of fossil-fueled electricity would alter the patterns of electricity trade on the bulk power system, in particular, the relationship between gas- and coal-fired electricity trade. However, given that fossil-fueled electricity generation almost always sets market prices, the overall effect would be to increase the price of electricity.

In the longer run, greenhouse gas limitations would also lead to more expensive electricity in the form of increased reliance on cleaner electricity generation technologies. Thus, these limitations might accelerate the retirement of existing power plants and hasten the construction of gas combined-cycle plants.

In both the long and short run, higher prices will tend to lower demand growth rates. Lower demand would tend to alleviate the rate at which pressures to support increased trade would influence operation and planning in the bulk power system.

We believe that the net effect of these factors would be a slowing of movement toward any of the last three scenarios. In other words, the scenarios 2-4 can be viewed as responses to pressure to change the status quo. The economic gains from increased trade in electricity are largely responsible for these pressures. Lower demand growth would dampen these pressures.

9.2 Greatly Increased Demands for Electricity

Greatly increased demands for electric services may result from a number of forces, including a) dramatic improvements in electricity storage technologies, which would increase market adoption of electric vehicles; and/or b) increased electrification of end uses because of environmental considerations or health/safety restrictions.

The likely effect of increased demand would be increased pressure for trade and additional demands on the bulk power system to move electricity from generators to consumers. These pressures would likely accelerate movement toward scenarios 2, 3, or 4. If movement toward scenario 2 or 3 were stalled for other reasons (such as political stalemates over the resolution of stranded assets), it is likely that movement toward scenario 4 would accelerate. That is, if increased pressure for trade cannot be met adequately (or securely) by the bulk power system, there will be increased pressure for distributed or dispersed generation as a means of by-passing (or augmenting) supply from the bulk power network.

9.3 Rapid Consolidation Among Market Participants

Consolidation would increase the political and market power of certain firms. The effects of consolidation may be two-fold, depending on the reason for it.

One possibility is that, if the interests of firms are not well served by movement toward more open markets (e.g., they have significant strandable costs), these firms will tend to slow movement from the scenario 1 toward either scenario 2 or 3. This may lead customers to independently accelerate movement toward scenario 4, especially movement toward complete off-grid operation. However, movement toward scenario 4 would likely be tempered by existing financial incentives to distribution companies to take actions to keep customers from leaving their system.

Another possibility is that, if the interests of firms are well served by movement toward a more open market, these firms will try to accelerate this movement. The public policy issue would then become which scenario, 2 or 3, is best equipped to deal with the market power that would accrue to these firms. It is difficult to answer this question in the abstract, although the economic efficiency of scenario 2 is predicated on the existence of effective means to prevent gaming by market participants (which would be challenged by participants with significant market power).

9.4 Cyber Threats to Power System Market and Physical Operations

There is growing awareness of the potential for malicious cyber attacks or cyber failures on the market and on the physical systems that support operation of the electric power grid. Responses to these threats may influence movement toward one scenario versus another.

For all four scenarios, there would be increased interest in RD&D for critical infrastructure protection. Scenario 2 would be more vulnerable in this regard than either scenarios one (because it is bigger, so consequences would be felt over a potentially larger area) or three (because it involves greater centralization, so it may be more vulnerable to attack). Scenarios 3 and 4 reflect institutional structures that are inherently more robust against these threats because they are more decentralized. However, the open nature of scenario 3 likely offers the greater opportunities for malicious intrusion, although the consequences of intrusion may be more localized.

9.5 Summary of Key Uncertainties

We have considered four key uncertainties that might influence movement toward or otherwise shape aspects of the scenarios. We find that an important influence of two of the uncertainties is on the demand for electricity; greater demand tends to increase the likelihood of all scenarios but the first; lower demands tends to dampen movement away from the first. The effect of the third uncertainty, consolidation among market participants, depends on the extent to which their near-term interests are served by the current situation (scenario one) or by more open markets (the second and third scenarios). The effect of the fourth uncertainty, deliberate and accidental cyber threats, argues for an increased emphasis on infrastructure protection in all scenarios, dampens movement toward the scenarios involving more open markets (especially the second), and increases the attractiveness of the decentralized features of the third and four scenarios.

10. Summary and Conclusions

This white paper has outlined four scenarios for the future of U.S. electric power system and identified key areas of needed reliability RD&D for each. We have also described appropriate roles for federal support for these needs and considered how four key uncertainties might affect movement toward each of the scenarios. In so doing, we have provided an introduction to the other five white papers in this project and an overall framework within which they examine aspects of selected RD&D needs in greater detail.

We conclude 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 the market-enabling 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.

Federal RD&D is especially needed for unbiased research to assist decision makers whose actions will have lasting reliability consequences for the future of this critical industry. Federal RD&D should be market enabling, not market determining. Private firms are unlikely to pursue in an unbiased fashion research in areas directly related to their future profitability or survival.

In view of the importance of electricity grid reliability to national welfare, these factors now call for an increased federal role in electric system reliability RD&D.

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.