Reliability and Distributed Generation

An Arthur D. Little White Paper

A

ARTHUR D. LITTLE

For more than a century, Arthur D. Little has been a leader in the consulting industry. Founded in 1886 by Arthur Dehon Little, it is the world's first consulting firm. Today, it still is one of the world's premier consulting firms, with over 3,500 staff members based in 51 offices and laboratories around the globe.

Arthur D. Little has been the world's leading consultant to the energy industry since the mid-1960s. We provide consulting services to the full gamut of industry players-major, independent, and national oil and gas companies; public and private utilities; independent power producers; government institutions; suppliers and contractors, and financial institutions and funding agencies. Bringing to all these assignments tailored, multi-disciplinary case teams, Arthur D. Little provides a range of services in strategy development, organizational design and implementation, business-process redesign, technology and product innovation, and environmental, health, and safety consulting.

DISCLAIMER

Funding for this white paper was provided to Arthur D. Little, Inc., by the sponsoring organizations for an objective analysis and discussion of important issues related to the use of distributed generation. This white paper is intended for general information and not as an endorsement of any product, process, or point of view.

Executive Summary

This white paper describes the reliability problems that have developed within the U.S. electric power system and demonstrates how Distributed Generation (DG) can provide an effective solution to those problems for both the system and individual customers. Additional economic, technical, and policy context for these policy discussions is provided by three other white papers in this series: "Distributed Generation: Understanding the Economics," "Distributed Generation: System Interfaces," and "Distributed Generation: Policy Framework For Regulators."[1] These discussion documents are designed to assist regulators, legislators, and other interested parties in understanding and evaluating issues associated with DG as they develop informed policies that will shape the future of the US electricity industry.

Despite a longstanding history of successful operations and customer satisfaction, recent highly publicized outages, customer alerts and load shedding in certain regions have led to changing perceptions and uncertainty about the electric power system reliability.

The U.S. electric power system is among the most dependable in the world, delivering to the vast majority of its customers a nearly uninterrupted flow of power with over 99 percent reliability.[2] High reliability is a central guiding principle for the U.S. electric power system and a key requirement for efficient commerce and industry as well as a high national standard of living.

Despite a longstanding history of successful operations and customer satisfaction, recent highly publicized outages, customer alerts and requests for load shedding in certain regions have led to changing perceptions and uncertainty about the system's reliability. There are three fundamental causes:

1. *Inadequate response to increased demand for electric power through insufficient and/or delayed generation, transmission, and distribution system upgrades and expansions, creating reduced (below 15%) reserve margins and zones of capacity shortfall in several parts of the country during peak seasons*
2. *Increased customer expectations for higher reliability than may be available from the current system*
3. *Weakening of traditional roles, responsibilities, and incentives for maintaining a uniformly high level of performance among U.S. power generation, transmission, and distribution systems*

These three developments have combined to help create new pressures on the balance between U.S. electricity supply and demand. Events during the past two summers have exposed zones of system weakness, particularly when demand is high. For many customers who cannot tolerate service interruptions and curtailments for even short periods, this is a high priority concern that requires an immediate solution. These concerns, and the absence of credible near-term system solutions, have led some endusers to consider creating their own reliability solutions that may be independent of the traditional electric power system.

1. These white papers can be downloaded from the Arthur D. Little Distributed Generation website at www.adl.com/dg/main/dg
2. Edison Electric Institute, 1998 Distribution Committee Reliability Survey, April 1999, as cited in Edison Electric Institute, "*America's Electric Utilities: Committed to Reliable Service*," May, 2000. (www.eei.org)

DG has gained attention as a viable technology option inherently well-suited to the geographically fragmented nature of the reliability problem.

DG has gained attention as a viable technology option inherently well-suited to the geographically fragmented nature of the reliability problem. DG is the integrated or stand-alone use of small, modular electric generation close to the point of consumption. It encompasses many distinctly different technologies that vary by size, application, and efficiency. Some, such as reciprocating engines, gas turbines, and photovoltaics have been commercially available for years. Relative newcomers–fuel cells, microturbines, and stirling engines–are being introduced today, with substantial improvements expected within the next few years. This suite of DG technology options can deliver prompt and cost-effective reliability solutions for a variety of applications.

DG can be installed within the distribution system or at a customer's site, as a separate solution or in combination with market-driven incentives such as interruptible programs, to improve reliability by:

- *Adding generation capacity at the customer site for continuous power and backup supply*
- *Adding system generation capacity*
- *Freeing up additional system generation, transmission and distribution capacity*
- *Relieving transmission and distribution bottlenecks*
- *Supporting power system maintenance and restoration operations with generation of temporary backup power*

Depending upon case-specific circumstances, DG may be able to offer several advantages over traditional central plant system generation upgrades, including being:

- *Flexible, including operation either as an islanded solution or in conjunction with the grid*
- *Sited and installed faster than conventional solutions*
- *Deployed to avoid or postpone potentially more expensive transmission and distribution upgrades*
- *Used in combination with energy storage and other power quality technologies for customized premium power solutions*
- *Able to provide non-reliability benefits, including implementation as a more energy efficient on-site option than grid power in BCHP (building combined heating, cooling, and power), and possibly providing electricity cost savings*

There are some limited DG initiatives under way to increase reliability in several major power markets, including programs established by the California and PJM Independent System Operators (ISOs) and by individual utilities in cities such as Chicago, New York, Kansas City and Portland, Oregon. Still, acceptance is not yet widespread.

The current industry transition period to competition has made it clear that the old collaborative, voluntary approach to reliability is difficult, if not impossible, to use in a restructured electric industry. New regulatory policies will therefore be required to create new solutions including market-based approaches to ensure reliability. To open markets to the practical consideration of DG for reliability, regulators and other stakeholders will have to confront potentially significant barriers involving electric rates, interconnection, and siting and permitting. There should also be a recognition of how market-oriented programs can be used to send the appropriate price signals when DG can be cost-effective.

To open markets to the practical consideration of DG for reliability, regulators and other stakeholders will have to confront potentially significant barriers involving electric rates, interconnection, and siting and permitting.

Policymakers now have the opportunity to develop DG policies to help address their own electric power system reliability concerns by learning from the experiences of colleagues in other jurisdictions, and by working with their own stakeholders to apply these lessons to local system conditions and markets. Through this exchange of information and the selective adoption of DG solutions being developed, tested or implemented in other states, it may be possible to more rapidly develop a common understanding of the principles of DG policy. These could include consistent DG equipment performance and interconnection standards and permitting processes, as well as methods for allocating DG costs and benefits to create appropriate market price signals.

If public decision makers can accomplish these tasks, DG will be allowed a fair evaluation by the market. This will in turn provide utilities, system operators, energy service providers and customers throughout the U.S. with the opportunity to consider DG as a viable and potentially superior option to strengthen electric power reliability.

Preface

This white paper is one in a series of discussion documents designed to help regulators, legislators, and other interested parties understand and evaluate issues associated with distributed generation (DG). It describes the current need to strengthen reliability in the United States, and how DG can help meet that need. It also examines key public policy issues that will strongly influence how DG will be allowed to compete in the marketplace.

DG represents a solution to some of the reliability problems faced by grid managers and electricity consumers, but DG does not represent an answer to all problems. An understanding of current reliability trends and concerns, and the role(s) DG could play in this area will enable policymakers to set priorities for investigating concerns and preparing responses. By proactively moving to understand the value of DG for reliability, they will help position themselves to develop informed policies that will shape the future of the U.S. electricity industry.

I. Introduction

The U.S. electric power system is among the most dependable in the world, delivering to the vast majority of its customers a nearly uninterrupted flow of power with over 99 percent reliability each year.[3] High reliability is a central guiding principle for the U.S. electric power supply, and a key requirement for efficient commerce and industry, as well as a high standard of living.

The U.S. electric power system is among the most dependable in the world, but recent highly publicized capacity constraints in certain regions have led to uncertainty about its reliability.

Despite the system's longstanding history of successful operations and customer satisfaction, recent highly publicized outages, customer alerts and requests for loading shedding in certain regions have led to changing perceptions and uncertainty about its reliability. There are three fundamental causes:

1. *Inadequate response to increased demand for electric power through insufficient and/or delayed generation, transmission, and distribution system upgrades and expansions, creating reduced (below 15%) reserve margins and zones of capacity shortfall in several parts of the country during peak seasons*
2. *Increased customer expectations for higher reliability than may be available from the current system*
3. *Weakening of traditional roles, responsibilities, and incentives for maintaining a uniformly high level of performance among U.S. power generation, transmission, and distribution systems*

Distributed Generation (DG) has gained attention as a viable technology option inherently well-suited to the geographically fragmented nature of the reliability problem. As the integrated or stand-alone use of small, modular electric generation facilities close to the point of consumption, DG can provide policymakers, regulators, and the market with flexible options to help resolve some of the power reliability problems now evident in the United States. DG represents an alternative to central plant generation through the use of existing or new sources of electricity at strategic locations in the distribution system or at customers' sites. DG can benefit either a portion of the local power delivery network or individual customers. Two ISO regions, utilities in several cities, individual companies and others are now undertaking DG initiatives to improve reliability, but acceptance is not yet widespread.

DG is often considered a relatively new solution that is not well understood by utilities, energy service providers, regulators, or customers. Increased understanding and new regulatory approaches are required to eliminate existing technical, economic, and procedural barriers and to establish the necessary market mechanisms to ensure that DG will be broadly considered as one potential response to reliability problems.[4]

3. Edison Electric Institute, *1998 Distribution Committee Reliability Survey*, April 1999, as cited in Edison Electric Institute, *"America's Electric Utilities: Committed to Reliable Service*," May, 2000. (www.eei.org)
4. National Renewable Energy Laboratory, *Making Connections: Case Studies of Interconnection Barriers and Their Impact on Distributed Power Projects*, U.S. Department of Energy, May 2000.

This white paper describes how DG can play a role in improving reliability, especially now during the current transition to a restructured market.

This white paper describes how DG can play a role in improving reliability, especially now during the current transition to a restructured market. This analysis presents policy-makers with a foundation for building their own responses to meet the needs of their constituents. The discussion begins with a review of the principles of electric power system reliability in Section II. Next, Section III presents a summary of traditional approaches to achieving reliability, followed by an assessment of the current power system reliability situation in Section IV. Section V is a description of how DG can provide solutions to reliability problems now faced by both utilities and customers. Section VI discusses a series of DG policy issues relating to reliability that regulators and others should resolve. Additional context for these policy discussions is provided by three other white papers in this series on DG.[5]

5. These white papers can be downloaded from the Arthur D. Little Distributed Generation website at www.adl.com/dg/main/dg

II. Principles of Reliability

Reliability is a key characteristic of a strong electric power delivery system. At its simplest, delivery system reliability is the measure of whether electricity is available to users.[6] A widely accepted definition for reliability is comprised of two elements: adequacy–the ability to satisfy market demand at all times, and security–the ability to withstand sudden disturbances such as short circuits or unanticipated loss of system elements.[7]

A widely accepted definition for reliability is comprised of two elements: adequacy–the ability to satisfy market demand at all times, and security–the ability to withstand sudden disturbances.

There are two fundamental causes of reliability problems:

- *Capacity deficiencies*
- *Faults and failures*

Capacity Deficiencies

Capacity deficiencies degrade the reliability of distribution, transmission, and distribution systems. They can arise from either an inadequate supply of power to meet market demand, or an inadequate contingent supply of electricity for an unexpected event. Either of these conditions may involve inadequate transmission and/or distribution capacity to transfer electricity within the power delivery system. Depending on the severity of the deficiency, an interruption of electricity supply (i.e., an outage) can occur.

A system capacity deficiency can lead to an outage if 1) system managers activate emergency procedures such as rolling blackouts to avoid further system overload and catastrophic failure, or 2) if the loss of a key system element results in serious overloads, cascading equipment failure, and potentially widespread blackouts. While power system planners and operators work to avoid such events, the simple lack of new generation, transmission and distribution capacity to meet increased demand has forced some operators to take precautionary emergency actions more routinely to maintain system reliability.

A capacity deficiency can also degrade reliability without causing an outage when the contingent supply of electricity to withstand unexpected events is reduced to a less severe, but still substandard level. In this case, a consumer may only be aware of the problem if a very low capacity margin causes local system managers to call for either voltage reductions or voluntary load shedding as a demand control measure.

6. By contrast, power quality describes the suitability of that electricity for servicing electrical loads, and concerns the shape of power waveforms.
7. North American Electric Reliability Council, *Reliability Assessment: 1999-2008*, May 2000, page 9.

There are two fundamental groups of causes of reliability problems: capacity deficiencies, and faults and failures.

Faults and Failures

Faults are short circuits in the transmission or distribution system that occur when protection equipment is insufficient against external events that cause a short circuit in energized electrical equipment such as power lines or substations. The most common sources of these are tree contact, animal contact, and lightning. They can also occur due to automobile accidents or vandalism. Failures occur when an element in the electric system ceases to function properly due to an equipment malfunction or human error not linked to any external influence such as those that can lead to faults. High voltage bushings, transformer windings, and lightning arrestors are common types of equipment that can fail, resulting in short circuits.

Both faults and failures can cause outages. These outages can be short, lasting less than 15 seconds and quickly resolved by automatic switching equipment. When a fault or a failure results in a longer outage, it typically involves damage to equipment such as a transformer that must be repaired or replaced before service can be restored. The time required for such remedies can range from hours to days or weeks. Faults and failures, rather than capacity deficiencies, are the causes of most outages. Outages created by faults and failures in generation are rare. While transmission faults are somewhat more common, 94 percent of all power outages are caused by faults and failures in the distribution system.[8]

Reliability is often measured against a baseline maximum of 100 percent for 365 days per year. The power system is designed typically to deliver between 99.9 percent (or "three nines") and 99.99 percent (or "four nines") reliability. There is no definitive industry statistic that measures the overall reliability of the US electric power system, although industry surveys are conducted periodically. In practice, the reliability of the system varies by location, but is generally over 99 percent.[9] Figure 1 illustrates the relationship between increased degrees of reliability and diminishing outage time.

Figure 1. Degrees of Reliability and Time Without Power

Reliability	Time Without Power
99.0% (2 Nines)	3.7 days/yr
99.9% (3 Nines)	9 hr/yr
99.99% (4 Nines)	53 min/yr
99.999% (5 Nines)	5 min/yr
99.9999% (6 Nines)	32 sec/yr
99.99999% (7 Nines)	3 sec/yr

8. Edison Electric Institute, *Underground vs. Overhead Distribution Wires: Issues to Consider*, May 2000. (www.eei.org) The transmission portion of the grid is a network of overlapping connections that provides redundancy and generally a high level of reliability. These overlaps allow system operators to correct for power plant outages or transmission line problems by routing available power capacity along alternative links in the transmission network. In contrast, distribution system design contains fewer overlapping linkages as feeders extend more linearly into customer territory. Although sectionalizing switches enable one area to draw power from another, outages at the distribution level are less easily averted, and therefore more common.
9. Edison Electric Institute, ibid.

III. Historical Perspective on Reliability Prior to Restructuring

Prior to the industry restructuring of the 1990s, responsibility for reliability was shared among various organizations that readily collaborated in a mostly voluntary environment to ensure appropriate planning and improvement.

Roles and Responsibilities

During the 1970s and 1980s, prior to the industry restructuring of the 1990s, vertically integrated utilities dominated the marketplace as regulated monopolies with exclusive responsibility for specific service territories. These companies owned, controlled, and operated their own central plant systems of local or regional generation, transmission, and distribution. Regulators rewarded utility investments in infrastructure reliability with customer rate structures that ensured profitability. In this protected market, responsibility for reliability was shared among various organizations, including the North American Electric Reliability Council (NERC), state and federal regulators, and utilities. No single regulatory body or industry organization held overall accountability for every aspect of reliability. These players readily collaborated in a mostly voluntary environment to ensure appropriate planning was conducted and system and operational improvements were implemented. Individual utilities often cooperated by forming power pools, and created strong interconnecting links among their systems to provide mutual support and increase system efficiency and reliability.

This approach worked well as the players were few and not likely to be competitors. Customers expected the utilities to ensure reliability, and utilities provided it through robust development of the transmission and distribution system, and through adequate reserve margin of central station capacity. Margin capacity remained strong in the 1980s due to major generation capacity additions during the prior decade. While there were isolated reliability events, there was no pattern of repeated outages or energy alerts that would indicate significant problems or pockets of weakness in the delivery system.

Engineering Solutions

Traditionally, utilities have proposed projects to improve reliability or capacity in transmission and distribution systems in response to their planning forecasts, operational problems, and/or customer request and complaints. Ideally, these improvements have been made as part of a comprehensive generation/transmission/distribution plan in the case of a vertically integrated utility. Apart from the addition of major new central generating plants, the scope of these projects has ranged from increasing the size of a customer's service to constructing new transmission lines and substations. In many cases, improvements such as these have been expensive and required many years to recover the investment after the facilities were placed in the rate base. Fortunately, such improvements typically have benefited many customers, making the costs justifiable. There are instances, however, when such improvements have benefited only a small group or even a single customer, making the investment less attractive from the perspective of the system as a whole. Siting and permitting requirements have also been important forces affecting traditional solutions, creating projects with very long lead-times and high costs.

Traditionally, utility reliability projects have ranged from new central generating plants, to constructing new transmission lines and substations, to increasing the size of the customer's service.

Power system operators have also routinely raised reliability by managing operations to more closely coordinate linkages between the different generation, transmission, and distribution elements of a system. For example, selected generation and transmission segments can be operated together to maximize their joint capacity, while peak demand delivery curtailments, rolling blackouts, and urgent appeals to customers for voluntarily power outbacks also have been effective.

Some reliability solutions have been implemented at customer sites, primarily through on-site backup power installations at commercial and industrial facilities. Backup power generation equipment (one form of DG), often linked with uninterruptible power supplies (UPS), has been available for over a decade to support critical company operations for a few minutes or hours during outages and to address other power quality problems.

IV. Current Industry Trends and Their Effects on Traditional Reliability

Weakened Roles and Responsibilities

The current transition period to competition has made it clear that the old collaborative, voluntary approach is difficult, if not impossible, to use in a restructured electric industry.

Federal and state legislative and regulatory actions since 1992, including the U.S. Energy Policy Act of 1992; the Federal Energy Regulatory Commission (FERC) Orders 888, 889, and 2000; and individual state restructuring legislation and regulations, have progressively introduced new types of players, structures, and rules to the market, effectively fragmenting and diluting existing responsibilities for reliability.[10] Market-based reliability solutions are still embryonic and not widely offered because market compensation is unclear.

This transition period to competition has made it clear that the old collaborative, voluntary approach is difficult, if not impossible, to use in a restructured electric industry. Deregulation has implicitly spread responsibility for reliability over many more stakeholders that now include FERC, NERC, generation companies (GenCos), transmission companies (TransCos), distribution companies (DisCos), retail energy service providers, Regional Transmission Operators (RTOs), and independent system operators (ISOs). Some of these entities are actual or potential competitors. At the same time, control and responsibility have been reduced or taken away from some longstanding players and their traditional tools for ensuring reliability have been weakened. In some jurisdictions, permitting and siting requirements and other relevant rules and laws have not been updated to reflect these restructuring changes.

Evidence of these industry changes is apparent throughout the system. Power system managers cooperate less than before, due to the unbundling of vertically integrated utilities into separate generation, transmission, and distribution business entities. Wires companies still see reliability as a primary mission, but these new entities often lack the regulatory permission and market incentives to collaborate with other market participants on electric power system operation and capacity planning to meet consumer demands. The transmission system that was designed for reliability in a non-competitive market is now increasingly used for complex commerce by wholesale energy sellers who bid for transmission system capacity as a commodity and transfer their electricity between regions. Responsibility for maintaining adequate generation capacity is often no longer the role of a single generation company. Instead, energy companies in restructured markets view generation as a competitive opportunity that may be pursued or

10. The U.S. Energy Policy Act of 1992 mandated the expansion of wholesale electricity competition. Federal Energy Regulatory Commission (FERC), Order 888 (issued April 24, 1996), Order 889 (issued April 24, 1996), Order 2000 (issued December 20, 1999), (www.ferc.fed.us/news1/isuances). Order 888 promoted both the wholesale competition through open access non-discriminatory transmission services offered by public utilities, and through the recovery of stranded costs by public utilities and transmitting utilities. Order 889 requires utilities that own, control, or operate facilities used for the transmission of electric energy in interstate commerce to create or participate in a real time information network that will provide open access transmission customers with data on available transmission capacity, prices, and other information that will enable them to obtain open access non-discriminatory transmission service. Order 2000 seeks to improve market performance through the formation of independent Regional Transmission Organizations (RTOs). These FERC efforts to manage the national transmission system address operational and reliability issues and eliminate competitive discrimination.

Electric utility industry restructuring has not progressed to the point where traditional reliability roles and responsibilities have been effectively replaced with market-based incentives.

ignored depending on market price signals and other business considerations. Prior to deregulation, ancillary services such as system control and dispatch, spinning and non-spinning reserves, and reactive power were provided as part of bundled energy services. Now these critical reliability components are treated as separate products in an embryonic market. Other regulatory factors such as costly and time-consuming local siting and permitting requirements add further complexity by allowing specific reliability problems to go unsolved.

These industry changes and recent peak period reliability events have led to a loss of confidence in the consistent reliability of the electric power system among regulators, industry participants and customers. Their concerns relate to:

- *Insufficient generation, transmission, and distribution system capacity*
- *The absence of responsibility and authority to compel implementation of solutions*
- *Uncertainty about who will make the necessary investments in power system infrastructure, and what will be built*
- *System operation, including dispatch and transmission functions*
- *The timing and impact of possible new regulatory models (e.g., performance-based ratemaking)*
- *High electricity pricing and volatility in many regions of the United States*

In summary, this transitional period of restructuring has not progressed to the point where traditional reliability roles and responsibilities have been effectively replaced with market-based incentives. Such market mechanisms are still in development, and include the buying and selling of energy and ancillary services, and satisfactory drivers to encourage required system expansion and upgrades, especially for the regulated portions of the system. Until these mechanisms have been firmly established and their potential financial rates of return are understood, market uncertainties will continue to discourage investment.

The Reliability of the System

High-profile power outages and non-outage disturbances during the summers of 1999 and 2000 indicate that important areas in the electric power system do not meet customer requirements for reliability (Figure 2). In the summer of 1999, outages and other power disturbances occurred in pockets of the Northeast, Mid-Atlantic, Midwest and South-Central United States. During that summer, significant portions of New York City and Chicago were without power for over 24 hours due to local system failures resulting from high demand. During the summer of 2000, outages occurred most regularly in California, as power system managers regularly announced energy alerts. Reserve margins in that state dipped below 5 percent at least 21 times during a three-month period, 14 of which resulted in voluntary load shedding.[11] In the same timeframe, states in the Southwest issued similar alerts, including Arizona and Texas (10 times in a five-month period). New England and the PJM ISO service area (all or part of

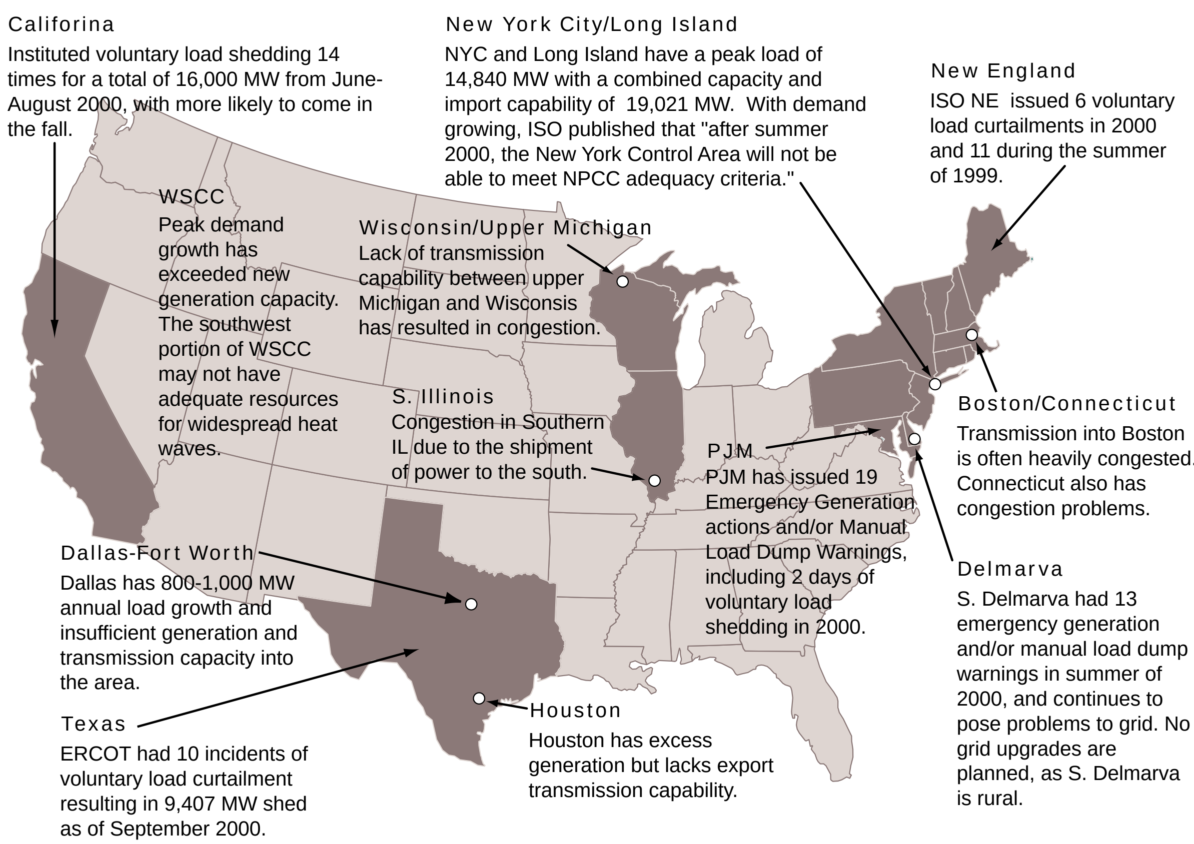
11. California ISO, Cal ISO PowerWatch 2000 archives, located on the California ISO website (www.caiso.com/newsroom/pw200).

Virginia, Maryland, Delaware, New Jersey, Pennsylvania and Washington, D.C.) also had a total of eight incidents of voluntary load shedding, despite the cool summer in these regions in 2000.[12]

As important as these outages and other reliability declines have been, localized hot spots are often not reflected in broad industry measures of reliability. For example, California is located within the NERC Western Systems Coordinating Council (WSCC) region (i.e., the Northwest Power Pool Area, and the Rocky Mountain, Arizona-New Mexico-Southern Nevada, and California-Mexico Power Areas) that reported a high overall generation capacity margins for the summer of 2000, as seen in Figure 3. Traditional utility service interruption statistics (e.g., SAIFI and SAIDI) reported to state regulators also might not provide an adequate measure of reliability among customers who do experience extended or repeated interruptions.[13]

High-profile power outages and other disturbances during the summers of 1999 and 2000 indicate that important areas in the electric power system do not meet customer requirements for reliability.

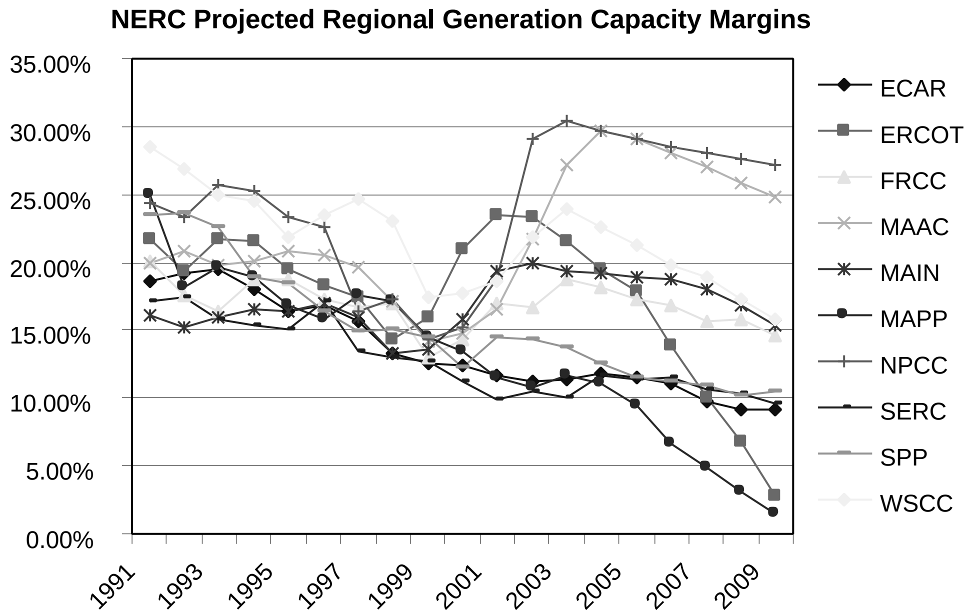
Figure 2. Examples of Local Weaknesses in the Electric Power Systems



12. PJM Heavy Load Days 2000 archive, (www.pjm.com/ecmsgsh/index), and NE ISO OP/4 Archives (www.iso-ne.com/power_system/op4_archives)
13. Utilities frequently report outage statistics that include their entire service territory (SAIFI, SAIDI, and MAIFI), as opposed to others (CAIFI and CAIDI) that state the frequency and duration of interruptions among those who experience these outages. This practice can, in effect, mask zones of weakness within a system-wide average. These reliability measures are defined and discussed further in the Appendix.

Analysis of these reliability events of the summers of 1999 and 2000 reveals causal similarities, including difficulties in the transition to competitive markets, inadequate system investment, and utility violations of reliability guidelines.

Figure 3. Trends in NERC Summer Capacity Margins By Region



Source: NERC, ADL

Analysis of these reliability events of the summers of 1999 and 2000 reveals causal similarities. The US Department of Energy (DOE) formed a Power Outage Study Team (POST) to study significant electric power outages and other disturbances during the summer of 1999, and published a report detailing the team's findings.[14] Separately, Arthur D. Little researched causal patterns for the events of the summer of 2000, and the FERC has investigated the summer of 2000 events in California.[15] These analyses indicate that the transition to competitive service markets was a moderate to high factor in nearly all of the outages and disturbances studied. Inadequate state and federal regulatory policy for reliable transmission and distribution was also frequently identified as a cause, and cited by DOE for "…not providing adequate incentives for utilities to maintain and upgrade facilities to provide an acceptable level of reliability."[16] Uncertainties related to deregulation have also affected timing and geographic coverage issues for investments in new generation facilities. These regulatory influences have been intensified by aged and deteriorating infrastructure, especially in densely developed cities.

Available infrastructure capacity and investment data support these conclusions. The shortage of adequate electricity generation cited above is reflected in substandard generation capacity margins in some U.S. regions. NERC projections of overall generation capacity margins during the U.S. peak summer season have declined from 22 percent in 1991 to the generally accepted minimum industry standard of 15 percent in 2000. Viewed individually, half of the NERC regions are currently experiencing levels below

14. U.S. Department of Energy (DOE), Final Report of the U.S. DOE Power Outage Study Team (POST), March 2000.
15. Federal Energy Regulatory Commission, *Staff Report to the Federal Energy Regulatory Commission on Western Markets and the Causes of the Summer 2000 Price Abnormalities, Part 1 of Staff report on U.S. Bulk Power Markets*, November 1, 2000.
16. U.S. Department of Energy (DOE), Interim Report of Report of the U.S. DOE Power Outage Study Team (POST), January 2000, p. S-2.

15 percent, and are projected to worsen further (Figure 3).[17] The historical deterioration of the transmission system has been be tracked statistically by the Edison Electric Institute (EEI), demonstrating that decreasing investment initially set the stage, and later became a key factor in the transmission infrastructure's inability to meet market demand.

While stress on the transmission system has increased, major bulk system transmission outages (defined as those lasting more than 15 minutes and affecting over 50,000 customers) have declined in recent years. This may be a reflection of a strong commitment to designing in and maintaining transmission reliability on the part of utilities and system operators. Despite generally high performance in limiting the number of transmission outages, there have been some notable exceptions in recent years such as the June and August 1996 western blackouts. The magnitude of these outages was due in part to heavy transfers on critical transmission lines.[18]

Bulk system reliability has also suffered from peak period system management practices. NERC has noted that deregulation has led various operators of bulk electric systems to support their own networks through reduced cooperation with other operators, causing a "marked increase in the number and seriousness of violations of voluntary reliability rules."[19] Although disregard for the policies of NERC and its regional councils has jeopardized the reliability of its three major interconnection regions and their ability to respond to additional contingencies, NERC holds no enforcement authority to correct the situation. NERC has observed that "little or no effective recourse exists today…to correct such behavior."[20]

Looking ahead during this transitional period of deregulation, planned increases in generation capacity over the next three to five years are expected to result in valuable but incomplete system reliability coverage. Recent new generation plant proposals have the potential to substantially expand overall capacity in some regions, as shown in Figure 3, but success is not guaranteed. These projects are subject to all of the financing, siting and permitting risks of larger central generation plants in deregulated markets. Also, the majority of the new plant proposals are from non-utility developers and their investors, and are targeted for peaking applications. Their decisions to proceed will be extremely sensitive to changing market conditions, and regulatory policies such as price caps can contribute to concerns about investment return.

Looking ahead during this transitional period of deregulation, planned increases in generation capacity over the next three to five years are expected to result in valuable but incomplete system reliability coverage.

Even if sufficient new supplies of generation are added, planned transmission capacity additions may not be capable of bringing all this new capacity to market. Despite the need for substantial new transmission capability, NERC and EEI both state that current plans may well be insufficient for new demand.[21] This is due to both inadequate invest-

17. ADL analysis of data included in NERC Energy Supply and Demand for 2000, NERC, 2000.
18. U.S. Department of Energy, The Electric Power Outages in the Western United States, July 2-3, 1996 (DOE/PO-0050), August 1996.
19. North American Electric Reliability Council, ibid., page 4. Additional information on voluntary rule violations is provided in the Appendix.
20. North American Electric Reliability Council, ibid., page 4.
As a result of this continuing pattern of reliability violations, NERC and other industry organizations have advocated federal legislation to create a single, industry-based Electric Reliability Organization (ERO) as a successor to NERC. The ERO would develop and enforce mandatory reliability rules with FERC oversight. The legislation containing this proposal has not yet been passed by Congress.
21. North American Electric Reliability Council, ibid; Hirst, ibid.

The fragmented but significant U.S. power system reliability problems can be expected to persist.

ment and poor coordinated planning of transmission and generation additions. With respect to distribution systems, reports to FERC are incomplete on local utility improvements, but available data do not indicate a pattern of spending increases among most regulated DisCos commensurate with expected future market demand.[22] The challenge of satisfying the market's power requirements is accentuated by unanticipated additions and shifts in load demand due to rapid changes in development patterns and the impacts of large customers' specialized requirements (e.g., for internet and data processing operations).

In summary, there are several key indicators of the emergence of zones of peak period reliability weakness in the U.S. electric power system:

- *Service interruptions and the increased use of voluntary reductions in consumption to protect the electric system in various areas of the country*
- *Several NERC regional generation capacity margins that are now below the generally accepted 15 percent threshold during summer peaking, and projected to decline further over the next eight years*
- *Transmission, and distribution system constraints that compound the regional shortfalls in generation capacity*
- *Patterns of insufficient infrastructure investment, due recently in large part to restructuring uncertainties*
- *Peak period system management practices by some operators of bulk electric systems that have at times jeopardized the reliability of the three major NERC interconnection regions and their ability to respond to additional contingencies.*

Current difficulties may be resolved in some geographic areas, but new areas of capacity constraint can be expected to emerge as the electric power industry continues to struggle to match local systems against continuing market growth. The fragmented but significant U.S. reliability problems can be expected to persist, due to a variety of factors, including accelerated market demand in some areas, existing infrastructure capacity shortfalls, investment uncertainties, and long central plant project completion timelines.

Public Perspectives on Reliability

There is a heightened awareness of reliability among customers, particularly in those areas of the country experiencing the effects of shortfalls in generation, transmission, and distribution capacity. A recent survey of residential customers found that after price, reliability is the most important consideration in switching electricity suppliers.[23] Reductions in reliability can cause commercial and industrial financial losses through:

- *Lost productivity*
- *Process disruptions and restarts*
- *Losses in finished products and raw materials*
- *Equipment damage*
- *Canceled contracts*
- *Penalties for failing to meet obligations*
- *Lost customers*

22. Resource Data International (FTEnergy Company), POWERDAT; Arthur D. Little, Inc.
23. Red Herring Magazine, *"Energy Positive Currents,"* July 2000, page 308.

The economic impact of electric reliability on customers can continue even after power is restored. Hewlett-Packard reports that a 20-minute outage at a circuit fabrication plant would result in the loss of a day's production at a cost of $30 million.[24] The value of reliability varies by customer type. At one end of the spectrum are those for whom outages of a few minutes or hours are generally inconvenient but not severe. This would include, for example, homeowners and businesses whose activities are not heavily dependent on a completely uninterrupted supply of electricity. In fact, these types of customers may be willing to be subject to these outages either in exchange for a lower electricity rate, or to avoid having to pay more to achieve higher reliability. At the other end of the spectrum are companies and other organizations for whom the effects of outages are relatively acute. For these customers, outages can cost tens of thousands of dollars to millions of dollars per incident (Figure 4).

Hewlett-Packard reports that a 20-minute outage at a circuit fabrication plant would result in the loss of a day's production at a cost of $30 million, and while smaller commercial customers do not typically experience losses of this magnitude, severe outages can have proportionally similar impacts.

Figure 4. The Costs of Outage for Selected Commercial Customers

Industry	Average Cost of Downtime
Cellular Communications	$41,000 per hour
Telephone Ticket Sales	$72,000 per hour
Airline Reservations	$90,000 per hour
Credit Card Operations	$2,580,000 per hour
Brokerage Operations	$6,480,000 per hour

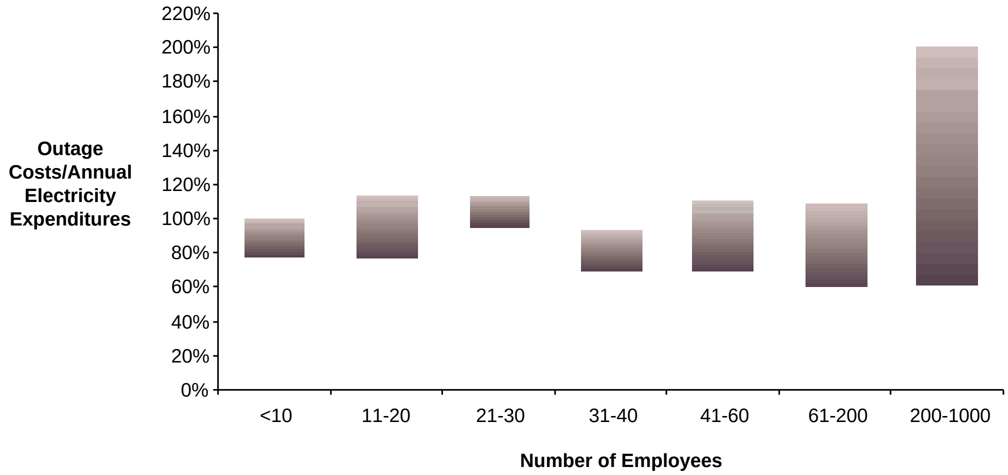
Source: Leiter, David,"Distributed Energy Resources", prepared by the U.S. Department of Energy for Fuel Cell Summit IV, May 10, 2000, Washington DC.

While smaller commercial customers do not typically experience losses of this magnitude, severe outages can have proportionally similar impacts with respect to their electricity costs. This demonstrates in a different way the value of reliability with respect to the basic price of power. Figure 5 shows an analysis of results from a California Energy Commission survey that measured the impacts of a severe outage on commercial customers. The ratio of severe outage costs to annual electricity costs was calculated for various sizes of commercial businesses, as measured by number of employees. In this analysis, regardless of business size, one severe outage is equivalent to approximately 75 percent to 125 percent of a customer's annual electricity expenditures. A severe outage for a small or moderate-sized business can therefore be just as damaging to its operations as an outage impacting a large business. While many larger businesses install back-up generators, smaller customers can find back-up generation too costly, even after factoring in the risk of high outage costs.

24. Silicon Valley Manufacturing Group Website: (www.projections.org/energy)

The speed of the economy, increasing productivity needs, and the expectations of consumers are strong influences on electric service reliability requirements that can only be realized by continued improvements.

Figure 5. Costs of a Severe Outage for Commercial Customers as a Percentage of Electricity Expenditures



Source: ADL Analysis of California Energy Commission Report, Survey of Implications to California of the August 10, 1996 Western States Power Outage, June 1997. ADL analysis was based on commercial customers survey responses to questions concerning a worst case electrical outage.

Customers that have experienced these outages or are aware of the potential for outages view reliability more critically than others. Their increased uncertainty and concern is leading them to consider their options far more carefully, including creation of their own solutions that, at least to some degree, could be independent of the traditional electric power system. In California during the spring of 2000, the Silicon Valley Manufacturing Group, a high-technology manufacturers' trade association whose members have particularly high reliability requirements, reacted to these outages by beginning to work aggressively on both short- and long-term electric power supply issues, including consideration of DG.

The speed of the economy, increasing productivity needs, and the expectations of consumers are strong influences on electric service reliability requirements. Even small companies are now adopting cost-cutting and efficiency measures such as just-in-time inventory that require high levels of power reliability for themselves and often their suppliers. Consumers will continue to demand faster, more convenient service that can only be realized by continued improvements in electric reliability.

The shift in the U.S. from a manufacturing economy to an information economy also requires more dependence on computer networks and telecommunications that have particularly high reliability requirements. The U.S, economy (both old and new) is increasingly reliant on computer networks, particularly for e-commerce applications. These telecommunications and computer network applications have extremely high demands for reliability (99.999+ percent) that exceed what the electric power system currently capable of delivering (approximately 99.0-99.99 percent). In these situations, customers purchase customized on-site reliability technology solutions that typically involve DG. These very high levels of reliability represent the leading edge of a broad trend towards a lower tolerance for service interruptions.

There is active debate on the amount of energy consumption represented by Internet and e-commerce and how much this type of electricity usage will grow.[25] Current estimates of electricity consumption related to the Internet range from 3-13% for 1999 and some studies have estimated that this could approach one-half of total consumption by 2010.[26] Regardless of where in these ranges the actual current and projected levels of consumption lie, computer network electricity consumption is now significant, growing fast, and will have increasingly important implications for electric power supply reliability needs.

Reliability is also expected to be a higher priority in the home as work patterns in the economy shift. In the past, residential customers viewed power outages as an inconvenience rather than in financial terms, but this may change as increasing numbers of Americans become telecommuters.[27] In 1999, there were 19.6 million telecommuters in the U.S., up 25 percent from 1998 and 125 percent from 1996.[28] This growth is being driven by advancements in technology (i.e., telecommunications and the Internet) as well as changing lifestyles.[29]

In summary, the value of reliability for electricity consumers varies widely. Economic, social, and technology trends will cause customer standards for reliability to continue to increase over time. The public's awareness of its reliability requirements and its uncertainties about the ability of the power system to meet customer needs will be hightened in particular among those experiencing outages or voluntary reductions. It will be this customer group that can be expected to most aggressively pursue solutions to ensure its own reliability.

Telecommunications and computer network applications have extremely high demands for reliability that represent the leading edge of a broad trend towards a lower tolerance for service interruptions.

25. Statement of Jay E. Hakes (Administrator, Energy Information Administration U.S. Department of Energy) before the Subcommittee on National Economic Growth, Natural Resources and Regulatory Affairs Committee on Government Reform, United States House of Representatives - February 2, 2000.
26. Lawrence Berkeley National Laboratory Website (www.lbl.gov); Mills, M. *The Internet Begins with Coal,* The Greening Earth Society, May 1999.
27. California Energy Commission Report, *Survey of Implications to California of the August 10, 1996 Western States Power Outage*, June 1997.
28. International Telework Association and Council (www.telecommute.org)
29. Ibid.

V. Distributed Generation

DG can provide policymakers, regulators, wires companies, and customers with multiple options to increase reliability.

Overview

DG can provide policymakers, regulators, wires companies, and customers with multiple options to increase reliability. The potential benefits of DG in addressing reliability concerns were specifically recognized in the DOE POST study as a way to "respond more rapidly to an increased demand for electricity in areas where demand is already high."[30] DG can be installed within the distribution system or at a customer's site, as a separate solution or in combination with market-driven incentives such as interruptible programs, to improve reliability by:

- *Adding generation capacity at the customer site for continuous power and backup supply*
- *Adding system generation capacity*
- *Freeing up additional system generation, transmission and distribution capacity*
- *Relieve a transmission and distribution bottlenecks*
- *Supporting power system maintenance or restoration operations with generation of temporary backup power*

DG can be operated at selected times, such as during peak periods or severe weather events when the probability of outages are highest or when a customer has scheduled specific operations that are highly sensitive to outages. Alternatively, DG can be operated continuously either in parallel with the electric power system to provide a portion of normal demand, or as a complete standalone source of power to satisfy total demand. DG can be implemented at the customer site by a variety of market participants, depending on local rules.

DG technologies vary in size, application, and efficiency. Technology performance and degree of commercialization must match with project operating requirements.[31] Some DG technologies, such as reciprocating engines, gas turbines, and photovoltaics, have been commercially successful for decades. Relative newcomers–fuel cells, microturbines and Stirling engines–are being introduced today, with substantial improvements expected within the next few years. DG can be combined with energy and storage power quality technologies to further enhance reliability and provide a customized power solution.

In customer-sited applications, whether deployed to satisfy a facility's total energy needs or to supplement the grid power supply, DG can allow the customer to obtain higher reliability than is available from the grid alone. However, the DG design must be properly sized and configured. DG will not always offer a superior, cost-effective reliability solution. When evaluating the reliability of a DG application, one must also consider factors such as the forced outage rate of the unit, fuel supply, environmental limits on

30. U.S. Department of Energy, *Report of Report of the U.S. DOE Power Outage Study Team (POST)*, March 2000, page 20.
31. Summary profiles of DG technologies are provided in the Appendix.

emissions and/or run time. The reliability of an individual DG unit does not equal that offered by the grid. However, when multiple DG units are used, or a single DG unit is used in conjunction with the grid, the resulting reliability can surpass that offered by the grid When used in combined heat and power applications to achieve high levels of energy efficiency via thermal recovery of DG thermal exhaust, or when implemented to provide electricity cost savings, DG can provide added benefits to complement reliability. DG's potential benefits are greatest when it is operated in parallel with the grid to provide maximum operational flexibility.

Some utilities and customers are already making good but limited use of the DG option to support reliability, both in individual customer installations and as an important element in utility and ISO initiatives.

In those situations where DG can increase reliability, it may also provide other advantages over traditional approaches, including being:

- *Flexible, including operation either as an islanded solution or in conjunction with the grid*
- *Sited and installed faster than conventional solutions*
- *Deployed to avoid or postpone potentially more expensive transmission and distribution upgrades*
- *Used in combination with energy storage and other power quality technologies for customized premium power solutions*
- *Able to provide non-reliability benefits including implementation as a more energy efficient on-site option than grid power in BCHP (building combined heating, cooling, and power), and providing electricity cost savings*

DG can be deployed as individual units or as an aggregated network to leverage the collective benefits of scale. For example, a control center could monitor the energy requirements of a network of commercial and/or industrial facilities equipped with DG, dispatching energy assets as required from one central point. This approach could satisfy the reliability needs of multiple facilities by balancing their individual use of DG against energy supply constraints and other market conditions on the grid. Similarly, a utility could operate an array of DG installations strategically placed on its distribution system or even, as is shown in the case studies below, at customers' sites. Contractual agreements between customers and utilities and/or system operators can ensure coordination and also maximize the effectiveness of other reliability initiatives such as curtailment programs.

Some utilities and customers are already making good but limited use of the DG option to support reliability, both in individual customer installations and as an important element in utility and ISO initiatives. This strategy frees up generation capacity on the system while allowing the customer to avoid loss of power for essential operations and exercise conservation where appropriate.

Three case studies are presented below to illustrate the two general approaches to deploying DG to improve reliability, the choice of which is dependent on the form of organization controlling the DG:

- *Utility, wires company or ISO*
- *Customer or Energy Services Company (ESCo)*

The IMEA saw an opportunity to provide additional value to its members' key accounts by improving reliability through DG.

DG Controlled by Utility, Wires Company, or ISO

For a utility, wires company, or ISO, DG can add generation capacity to the system and relieve specific transmission and distribution constraints, and can be implemented by a variety of market participants. If permitted by regulators, distribution utilities could either own and operate the DG unit (including customer-sited DG) or contract with an unregulated provider to do so. The incentive for the distribution utility depends on how the financial benefits and costs from the operation of the unit are shared among the affected parties, including the distribution utility, the DG service provider, and the customer. As seen in the second case study, the ISO can also operate the DG unit(s), although another party such as the DisCo, an ESCo, a third party, or a customer would own the installation. Again, these parties would enter into this type of arrangement if they received sufficient benefits.

If a utility is not allowed to own DG, it may be able enter into an arrangement with another party such as an ESCo or a customer with an on-site unit that is allowed to own generation capacity. Again, from the utility's perspective, this would make sense as long as it receives sufficient benefit from the arrangement (e.g., lowest cost additional capacity) and is allowed by regulators to recover any DG-related costs plus a return.

Case Study: Municipal Utility Application of DG

The Illinois Municipal Electric Agency (IMEA) is a non-profit organization that purchases electricity for 39 municipal electric utilities in Illinois. In response to deregulation, the members of IMEA have identified key accounts that are not only important to IMEA but are also vital to the economic well-being of the communities that its members serve. While key-account customers were generally pleased with the level of service they were receiving, IMEA saw an opportunity to provide additional value to its members' key accounts by improving reliability through DG. The key-account customers most vulnerable to interruptions were manufacturers operating their businesses with "just-in-time" contracts, under the terms of which they would pay severe penalties for failing to fill orders on schedule. Power outages can cost these manufacturers $300,000 to $600,000 per hour.

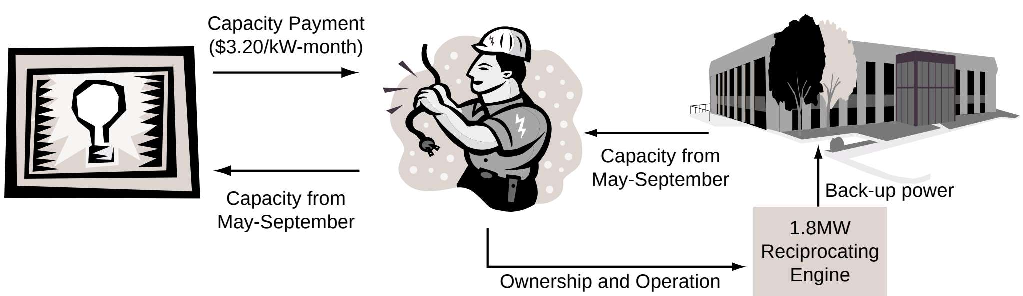
In addition, IMEA was faced with growing peak demand and changes in contracts with major power providers that created a shortfall in its near-term power supply requirements. However, it would not have been economically possible for IMEA to cover this potential deficiency by purchasing firm capacity on the market in advance. Also, the "agency was uncomfortable with the risk of purchasing this amount of capacity on an hourly basis as needed…when prices have soared to unprecedented levels in recent years."[32] To respond to these needs, IMEA developed the Just In Time Key Accounts (JITKA) program.

32. Ronald D. Earl, "*Distributive Generation and Just In Time Key Account (JITKA) Program (Plus…IRP 2000),*" Illinois Municipal Electric Agency, September 21, 2000, page 5.

In the JITKA program, the IMEA utility member purchases and installs quick-start 1.8MW generators at its participating customers' sites (Figure 6). IMEA pays these members a capacity payment of $3.20/kW-month to have this generation available for IMEA to dispatch during the five summer months. In the event of an outage, the generation is also used to provide emergency power to that customer. In the implementation of JITKA, IMEA stipulated that its members could not use the equipment to 'peak shave' load requirements to reduce Agency billing. In addition, the members are responsible for interconnection and environmental permitting. Credits for each installation are approximately $150,000 over a five-year period, about 1/3 the installed cost of the generation equipment. The program has been accepted by IMEA's members, their customers, and the community. Ten key accounts (totaling 20 MW) are now served under the JITKA program and IMEA is planning for expanded participation.

In the JITKA program, the IMEA member purchases and installs quick-start 1.8MW generators at its participating customers' sites, and the IMEA pays these members a capacity payment of $3.20/kW-month to have this generation available for IMEA to dispatch during the five summer months.

Figure 6. IMEA JITKA Program Summary



IMEA Benefits	IMEA Member Benefits	Customer Benefits
Stable, competitive pricing for summer peaking capacity, protecting IMEA from uncertainties of hourly prices that have gone as high as $9,000 MWhr Possible deferrment of IMEA need for transmission or large-scale generation facilities Higher level of sales to expanding accounts and retention of key accounts who are less likely to wheel electricity	Increased key account satisfaction Less key account desire to wheel electricity Increased electric sales due to plant expansions or less sales lost due to outages Increased value of the municipal utility as each generator has an initial value of $450,000	Increased electric reliability, preventing electric service interruptions Increased product sales due to ability to prove to assembly plants that electric outages are unlikely, resulting in secured contracts Decreased unit operating costs and insurance costs related to lost production policy premiums

The PJM program demonstrates one broad-based approach for using DG to improve system reliability, with customers being reimbursed based on kWh relief supplied.

Case Study: DG at the ISO Level

PJM Interconnection integrated existing on-site DG into its Customer Load Reduction (CLR) Pilot Program.[33] The CLR Program was developed during spring 2000 in anticipation of potential exhaustion of capacity margins during the coming summer's peak periods. Although PJM experienced capacity constraints during the summer of 2000, the relatively mild weather overall allowed it to avoid declaring an Energy Emergency that would have triggered program activation. Nevertheless, the program demonstrates one broad-based approach for using DG to improve system reliability, and PJM has stated that the current program will be the basis for future initiatives.

The CLR Pilot Program was PJM's response to a FERC order issued in May 2000 to encourage continued electric power system reliability in the summer of 2000. It was designed to allow PJM to help relieve anticipated system constraints and observe how DG could participate in PJM emergency procedures, especially the equipment's emergency, back-up, and load reduction capabilities. End users would receive economic incentives to reduce load on the electric power system. This pilot reliability program was in force from the beginning of July through the end of September, and was to be activated when PJM declared Maximum Emergency Generation prior to purchasing emergency energy from outside its territory.

Qualifying program participants had to be able to either 1) completely disconnect from the local distribution system and supply required load via local generators, or 2) reduce a measurable and verifiable portion of their load. In addition, individual participants were required to:

- *Be capable of reducing at least 100 kW of load*
- *Be able to participate for a total of at least 10 hours over the pilot operating period*
- *Be available any hours between 9 a.m. and 10 p.m. seven days a week*
- *Be capable of achieving full reduction within one hour of PJM's request to reduce load*
- *Be capable of receiving PJM notification*
- *Meet the metering requirements to verify the load reduction*

Customer participants would be reimbursed based on the kWh relief they supplied, with PJM paying the higher of the appropriate PJM zonal Locational Marginal Price or $500/MWh. All program charges were to be allocated to the purchasers of energy in proportion to their net purchases from the PJM energy market during the hour. Among the 52 sites with a total of 102 MW that applied for the program, PJM approved 43 sites for a total of 80 MW of potential load reduction. The largest site offered a 15 MW load reduction, and the smallest offered 120 kW. PJM estimates that approximately 40 MW represented DG capacity.

The PJM DG Users Group formed to develop and oversee the program observed that the strengths of the initiative included its voluntary nature and the associated lack of any penalties, its simplicity and flexibility, and a relatively good potential return upon implementation. The group identified the negative aspects of the program to be the rudimentary nature of notification (e-mail or pager) and the lack of a guaranteed revenue stream (i.e., no compensation if not called on in an energy emergency). Metering was a major issue for some customers due to the installation expense and the uncertainty involved with the calculation of the actual load reduction as prescribed by the pilot program. During the winter of 2000-2001, the Users Group expects to focus its efforts on designing a long-term program incorporating DG into PJM emergency procedures for implementation by summer 2001.

33. PJM Interconnection, *PJM Customer Load Reduction Pilot Program*, updated July 14, 2000 (www.pjm.org)

DG Controlled by the Customer or ESCO

DG can be deployed at a customer's site to deliver backup power or to provide uninterrupted power when operated in conjunction with the electric power system and/or with energy storage technology. The customer could own and/or operate the DG unit, or contract with a third party such as an ESCO to provide these services. DG facilities can be managed individually or as a networked pool in this option.

Case Study: California Hospitals

Power supply constraints in some regions of California have compelled many businesses, including hospitals, to shed significant load, often with little warning.[34] These curtailments have demonstrated many hospitals' need for additional reliability planning. A few hospitals with environmental permits that allow the practice, are activating their standby units as DG during summer peaks for their own essential operations when they elect to respond to utility requests to curtail power from the grid. While this option may not be appropriate for all hospitals, this case study highlights an important set of problems and choices, and a potential DG opportunity that could provide benefits for these institutions and the electric power system.

A few California hospitals with environmental permits that allow the practice are activating their standby units as DG for their own essential operations during summer peaks, when they elect to respond to utility requests to curtail power from the grid.

Many California hospitals participate in interruptible (or "non-firm") electric service programs for businesses introduced in 1979. These hospitals entered into non-firm contracts to obtain 10 to 15 percent rate discounts. Until recently, the interruptible service option proved to be attractive for many of these institutions because interruptions were extremely rare. During the summer of 2000, however, many hospitals with interruptible service were repeatedly instructed by their utility to reduce their loads to their contracted firm-service levels. Hospitals that had maintained realistic plans to curtail their loads performed this load shedding without incident. Those with nonexistent or outdated plans either did not respond at all, or partially complied through measures such as shutting off much-needed air conditioning. Penalties of up to $9.30/kWh for non-curtailment were severe enough to drastically reduce or eliminate these hospitals' non-firm savings and increase electric costs significantly. Facility managers were also frustrated by the frequency of curtailments and that many curtailment orders reportedly were received late, with many withdrawn and subsequently re-ordered.

Many of the participating hospitals and other industrial and commercial customers have reportedly been planning to either withdraw from the interruptible program in fall 2000 or increase their firm service commitments with their utilities. Responding to the need to relieve the state's overall generation capacity constraints, the California Public Utilities Commission (CPUC) opened a rulemaking in October 2000 designed in large part to identify ways to increase the use of interruptible load programs to "ensure reliable and reasonably-priced electric service within California, especially for summer 2001." [35]

34. California utilities ordered three Stage-2 non-firm curtailments in 1998, and one in 1999. In 2000, the California Independent System Operator (CAISO) has called 27 Stage-1 events, and 21 Stage-2 curtailments as of the end of November. (www.caiso.com/newsroom/pw2000). This case study was prepared through the assistance of Powel B2B Services, Inc.
35. California Public Utility Commission, "*Order Instituting Rulemaking Into The Operation of Interruptible Load Programs*" October, 2000. (www.cpuc.ca.gov)

Results might be optimized if these DG facilities were managed as a network, or several networks, to increase efficiency and scale.

Case Study: California Hospitals

Instead of relying on firm rates to ensure adequate power supply, a few hospitals use the interruptible rate and obtain reliability by deploying their standby emergency generating systems within their permitted limits as DG during power curtailments. Even with permit limitations on operation, the reliability benefits of DG during peak curtailment periods has proven to be significant for some. Two examples include:

- *A Northern California hospital with a peak demand of 3 MW and a firm service level of 1 MW joined the interruptible program in 1995. Since that time, it has used its emergency generation assets within permitted limits to replace curtailed power for essential operations.*

- *A hospital located in the Southern California desert currently has a demand of 6.5 MW and firm service level of 2 MW. The facility has managed its load and operated its DG satisfactorily to compensate for curtailed load without penalty or incident. The load has increased 2 MW since it joined the interruptible program in 1988 and it is has become more difficult to curtail without shutting off air conditioning loads. As a result, the facility is now considering installing more generation or increasing the firm service level.*

Most California hospitals have not yet pursued this DG alternative because of emissions limitations and/or the fact that power generation is not a core competence, but this might change to some degree. Continued generation capacity constraints, energy price uncertainties, the CPUC interruptible rate initiative, and other factors in California may increase the incentives for hospitals there to selectively use their standby generation as DG in the coming years. This could become an even more practical solution for hospitals that must upgrade their backup power installations to comply with state seismic emergency requirements, and select technologies with emissions profiles that would permit increased use.[36] Results might be optimized if these facilities were managed as a network, or several networks, to increase efficiency and scale. Air pollution control issues will be a critical consideration. If such issues could be resolved, hospitals in California might decide to activate more of their estimated 500 to 750 MW of existing standby capacity as DG when needed as both relief for the grid and support for hospital operations.

36. Many hospitals have determined they must replace existing central energy plants to comply with a 1994 California law that requires all acute care hospitals to conform to minimum seismic standards.

VI. Policy Implications

Public policy should more broadly recognize the potential for DG to help strengthen zones of weakness in the U.S. power system. Possible costs and risks of DG should also be incorporated into policy considerations to ensure fully informed decisions. Several public policy issues relate directly to DG and its capacity to improve electric power reliability, including:

- *Electric rates and market-oriented programs*
- *Interconnection requirements*
- *Siting and permitting*

Several public policy issues directly relate to DG and its potential to improve reliability: electric rates and market-oriented programs, interconnection requirements, and siting and permitting.

Regulatory ratemaking initiatives should consider several options that could create accurate price signals to indicate when DG is a cost-effective reliability solution.

- *Performance-Based Ratemaking (PBR) rewards strategies that increase system load factors to improve asset utilization. This approach can provide utilities with a financial incentive to deploy (or allow others to deploy) DG when it is a superior alternative to the traditional central plant model.*
- *Markets for ancillary services are only now emerging, because this suite of services traditionally offered by vertically integrated utilities is being unbundled by restructuring. Ancillary services are critical to a reliable electric power supply, and programs that encourage this market create the opportunity for DG to participate in providing these services.*
- *Standby and exit fees are potential cost barriers to the adoption of DG, and regulators should balance the benefits of imposing different magnitudes of these costs against any net reliability (and other) benefits that might be obtained through the use of DG.*

From a retail market or customer perspective, policies to encourage market-oriented programs could help the customer recognize and select cost-effective reliability options, including DG when applicable. There are several alternatives for sending the appropriate signals to consumers to support reliability at critical times. In the past, these have included urgent appeals to the customer for conservation, as well as time-of-use, curtailable and interruptible rates. As deregulation and restructuring proceed, the traditional rate base funding for load management programs will cease, and market-oriented approaches will be required to support these activities. Options include real-time and zonal pricing, along with modified versions of time-of-use, interruptible, and curtailable rates that are more closely linked to market costs and benefits. Marketplaces can also be created to buy and sell demand. Actual electricity rates would still be determined by PUCs and utilities, but retail pricing and marketplace approaches could be structured in a variety of ways and could be controlled by entities such as ISOs, retail energy providers, and other private entities. In a restructured industry, financial support for such reliability programs will also depend on their ability to generate explicit benefits.

The technical and economic aspects of interconnection requirements, processes, and contracts are currently receiving high levels of attention and visibility. These issues affect the flexibility with which DG can be used, including for reliability purposes. Although it is possible to operate DG equipment in "island mode," isolated from the electric power system, many DG customers are expected to prefer or require intercon-

As decisionmakers consider the use of a specific DG technology to improve reliability, they may need to balance potentially competing issues such as environmental quality, technology selection (including fuel alternatives), and the need for adequate power supplies, particularly during periods of peak consumption.

nection. The Institute of Electrical and Electronics Engineers (IEEE) will complete its Standard for Interconnecting Distributed Resources with Electric Power Systems (P1547) in 2001, and this is expected to serve as the foundation for individual state requirements.[37] DG interconnection policies are already being established in several states (with an eye on the IEEE proceedings) to address DG access to the grid while ensuring the safety and reliability of the system. Regulatory researchers on this topic can consult successful working examples of parallel DG interconnection throughout the U.S., and the DG interconnection standards recently adopted by Texas and New York. The cost of DG compliance with existing interconnection procedural and technical requirements should be evaluated to ensure that they do not present unnecessary barriers. Some states have developed technical interconnection requirements and review processes as the first step in creating DG policy. This sequencing of activities resolves narrower, more technical issues such as approval requirements and the parameters (e.g., sizes and types) of DG installations to be allowed, before policymakers consider broader issues such as ownership, ratemaking, and markets.

Siting and permitting are also key concerns that can directly influence if and how DG may be deployed. Policymakers are being asked to consider whether there are opportunities to reduce the time and cost associated with siting and permitting DG and still protect–and perhaps even strengthen–the environment, public health and safety, and other social priorities. Most DG facilities are too small to trigger most states' power generation facility siting requirements, which were established for central plants. However, DG units may be required to comply with local, state, and regional permitting requirements, as well as building and fire codes. Issues typically relate to location-specific concerns. The main focus is frequently air emissions, but other local sensitivities may include factors such as noise, aesthetics, land use, and risk communication. Overall, there may be several applicable (and potentially overlapping) permits, codes, and requirements, each with its own separate process, constituency and decisionmakers.

Air emissions permitting in particular can be a critical DG issue. Emissions profiles may raise significant concerns, depending on location, air quality conditions, and applicable regulations. As an energy strategy that can use different technologies with vastly different environmental profiles, the DG concept itself is environmentally neutral. For example, natural gas-powered technologies have lower emissions than diesel engines. Fuel cells are lower still, and photovoltaics have no operating emissions at all. New proposed DG air permitting requirements in some states may limit choices among these technologies.

As decisionmakers consider the use of a specific DG technology to improve reliability, they may need to balance potentially competing issues such as environmental quality, technology selection (including fuel alternatives), and the need for adequate power supplies, particularly during periods of peak consumption. These peaks typically occur on

37. This will be a national, uniform and voluntary standard for the industry and policymakers. Individual states may choose to provide additional elements in their own mandatory requirements to address their particular conditions and needs.

hot summer days when conservation measures are already in force and air quality may be poor. At such peak times, the need for power is often high for home cooling and essential activities at locations such as health care facilities, other public service institutions, and heat-sensitive business operations (e.g., data processing centers).

The varied initiatives to use DG now underway in constrained regions of the U.S. provide decisonmakers with examples to consider as they shape their own reliability policies.

One scenario that might require weighing environmental impacts against other considerations would be a network of DG at various facilities in separate locations to provide non-spinning system reserves. A network of DG installations, each with quickstart capability for non-spinning reserves, can be activated as needed in smaller, incremental steps, as opposed to continuously operating the larger central plant to provide the same total amount of non-spinning reserve. Depending on actual market demand, some or all of these DG facilities might seldom or never be called on, creating lower emissions than the central plant. Alternatively, market conditions might require these DG facilities' non-spinning reserves to be called on frequently to protect system capacity margins, thereby producing emissions in their individual locations that could raise local concerns. Policy tradeoffs in this case could include:

- *Technology and fuel selection*
- *Air permit compliance issues*
- *Local health risks posed by the expected emission levels at the various DG sites, compared to those of the central plant*
- *Any differences in reliability benefits offered by the two options*

The varied initiatives to use DG now underway in constrained regions of the U.S. provide decisonmakers with examples to consider as they shape their own reliability policies. Through an exchange of information and the selective adoption of workable solutions already being developed, tested or implemented in other states, it may be possible to more rapidly establish a common understanding of the principles of sound DG policy. These could include consistent DG equipment performance and interconnection standards and permitting processes, as well as methods for allocating DG costs and benefits to create appropriate market price signals.

VII. Conclusions

There is growing recognition among regulators, utilities, customers, and others that DG can be an effective strategy for solving a portion of the fragmented reliability problems in the U.S. electric power system.

There is growing recognition among regulators, utilities, customers, and others that DG can be an effective strategy for solving a portion of the fragmented reliability problems in the U.S. electric power system. These problems, caused by numerous specific local and regional capacity constraints, are evident during periods of peak demand, and occur when generation, transmission and/or distribution capacity is inadequate to meet the rising market demand for increased reliability and power. The challenge of satisfying the market's power requirements is accentuated by poor coordination among industry participants, and by unanticipated additions and shifts in load demand. These shifts are due to rapid changes in development patterns and the impacts of large customers' specialized requirements (e.g., for internet and data processing operations).

DG can be inserted as a customized power generation source at strategic locations within the system or at the customer site to meet specific capacity and reliability requirements. While central station types of additions to the power system will be required in many cases to improve reliability, in other instances this approach will not provide a practical, cost-effective or timely response to immediate or highly localized reliability needs. In at least some of these situations, DG can deliver a superior solution and possibly eliminate or postpone the need for more expensive, large scale system upgrades that are slower and more complex to implement. DG can provide added benefits to complement reliability when combined with other power quality technologies used in combined heat and power applications to achieve high levels of energy efficiency, and/or implemented to provide electricity cost savings.

This transition period to competitive electric markets has made it clear that the old collaborative, voluntary approach to reliability is difficult, if not impossible, to use in a restructured electric industry. New regulatory policies will be an important influence on the development of the necessary market mechanisms to ensure reliability. But in many jurisdictions, policies do not yet adequately accommodate the consideration of DG. Decisionmakers may need to create explicit DG procedures and technical requirements that will allow open consideration of DG both on the system and at the customer site. As part of this, regulators and other stakeholders will have to confront potentially significant barriers involving electric rates, interconnection, and siting and permitting. There should also be recognition of how market-oriented programs can be used to help send appropriate price signals. Rates should provide utilities and other stakeholders with a financial incentive to deploy DG when it offers a more cost-effective reliability alternative than traditional central station remedies. Interconnection requirements should be reasonable, reflect the technical successes already achieved in the industry, and pose no unnecessary procedural or financial barriers.

There are numerous DG programs and installations now in place in the United States and available for regulators to consider as they develop explicit DG policy. These DG activities are often conducted in conjunction with interruptible or other demand side management programs. Despite these successes, DG has been deployed on a limited scale to improve reliability, and is still considered to be a relatively novel approach. The lack of a common understanding of DG technologies, their capabilities, and related important technical issues such as DG interconnection with the electric system can effectively discourage its consideration.

Policymakers now have the opportunity to develop DG policies to help address their own electric power system reliability concerns by learning from the experiences of colleagues in other jurisdictions, and by working with their own stakeholders to apply these lessons to local system conditions and markets. If public decisionmakers can implement effective and consistent DG policies such as consistent equipment performance and interconnection standards and permitting processes, as well as methods for allocating costs and benefits to create appropriate market price signals, DG will be allowed a fair evaluation by the market. This will in turn provide utilities, system operators, energy service providers and customers throughout the U.S. with the opportunity to consider DG as a viable and potentially superior option to strengthen electric power reliability.

If public decisionmakers can implement effective and consistent DG policies, DG will be allowed a fair evaluation by the market. This will in turn provide utilities, system operators, energy service providers and customers throughout the U.S. with the opportunity to consider DG as a viable and potentially superior option to strengthen electric power reliability.

Selected Bibliography*

Alderfer, R. Brent, M. Monika Eldridge, and Thomas J. Starrs, *Making Connections: Case Studies of Interconnection Barriers and their Impact on Distributed Power Projects*, National Renewable Energy Laboratory, May 2000. (www.eren.doe.gov/distributedpower/barriersreport/)

California Public Utilities Commission, *Order Instituting Rulemaking into the Operation of Interruptible Load Programs 00-10-002*, filed October 5, 2000. (www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/2831)

Edison Electric Institute, *Comments of the Edison Electric Institute on Longer Term Actions to Promote Reliability, Testimony Before The Federal Energy Regulatory Commission, EL00-75-00*, filed June 30, 2000. (www.eei.org)

Edison Electric Institute, "*America's Electric Utilities: Committed to Reliable Service*," May, 2000. (www.eei.org)

Federal Energy Regulatory Commission, *Staff Report to the Federal Energy Regulatory Commission on Western Markets and the Causes of the Summer 2000 Price Abnormalities, Part 1 of Staff report on U.S. Bulk Power Markets*, November 1, 2000 (www.ferc.fed.us/electric/bulkpower)

Hurst, Eric "*Electric Reliability: Potential Problems and Possible Solutions*," , Edison Electric Institute, May 2000. (www.eei.org/issues/reliability)

Hurst, Eric "*Expanding U.S. Transmission Capacity," Edison Electric Institute*, July 2000. (www.eei.org/issues/reliability)

National Regulatory Research Institute, *NRRI Reliability Survey* (internal document), 1998. (www.nrri.ohio-state.edu).

National Rural Electric Cooperative Association, *White Paper on Distributed Generation, 2000*. (www.nreca.org)

North American Electric Reliability Council, *Reliability Assessment: 1999-2008*, May 2000. (www.nerc.com/publications/annual)

North American Electric Reliability Council, *2000 Reliability Assessment: Reliability of the Bulk Electric Supply in North America*, May 2000. (www.nerc.com/publications/annual)

U.S. Department of Energy, *Interim Report of the US DOE Power Outage Study Team*, January 2000. (www.energy.gov/library/index)

U.S. Department of Energy, *Final Report of the US DOE Power Outage Study Team*, March 2000. (www.energy.gov/library/index)

U.S. Department of Energy, *Horizontal Market Power in Restructured Electricity Markets*, March 2000. (www.energy.gov/library/index)

U.S. Department of Energy, *The Electric Power Outages in The Western United States*, July 23, 1996. (DOE/PO-0050), August 1996. (www.energy.gov/library/index)

* This bibliography lists major sources used most directly in the preparation of this White Paper. It is not intended to represent the broader body of publications on DG and reliability.

Appendix

1. DG Technology Profiles

	Residential	Commercial	Industrial	Grid-Distributed	Remote/Off-Grid Distributed	Typical Unit Size Range (installation size can be larger)	2000 Installed Capital Cost ($kW)	Efficiency (%)	Commercial Availability
Reciprocating Engines	●	●	●	●	○	5 kW - 20 MW	400-600[1]	28-40	Now
Stirling Engines	●	●			○	0.5 - 200 kW	NA[2]	20-32	2001+
Small Gas Turbines		●	●	●	○	500 kW - 20 MW	650	25-40[3]	Now
Microturbines[4]		●	●	○	○	25 - 500 kW	1,000-1,300	22-30	2000
High-Temperature Fuel Cells		●	●	●	○	50 kW - 3 MW	NA[5]	45-55	2003
Low-Temperature Fuel Cells									
PAFC	●	●	○	●		50 - 500 kW	3,000+	34 - 40	Now
PEM	●	●	○	○	○	1 - 250 kW	NA[6]	30 - 40	2001+
Photovoltaic Cells	●	○		●	●	0.05 - 200 kW	6,000 - 10,000	12 - 13	Now

1. Large, gas-fired reciprocating engine
2. Not available, projections of $700-1,500/kW
3. Forty percent efficiency achieved with advanced turbine cycle
4. Recuperated microturbine
5. Not available; projections of $1,000-2.000
6. Not available; projections of $1,000-2.000

Legend: ● =Primary Target Market

○ =Secondary Target Market

2. Utility Reliability Performance Measurements

In the regional and local sections of the grid, the reliability of transmission and distribution systems are reported in terms of the number and duration of power interruptions or "outages" per year. The IEEE Standard 1366 contains several reliability indices that reflect the frequency of these types of outage at the distribution system level. These indices also reflect the system managers' abilities to minimize the impacts to the distribution system of upstream reliability problems in the transmission network and central generating plants. Utilities maintain and routinely report some or all of this data to public utility commissions and other stakeholders.

These statistics measure only interruptions of service, and not any voluntary customer load shedding requested by utilities. While load shedding is effective for avoiding outages, it is, in effect, a reduction in a customer's service availability due to inadequate supply. In addition, utility reliability reporting requirements vary from state to state, making direct comparisons difficult, and indicators such as SAIFI and SAIDI average interruptions across entire service territories during one year. These measures are important gauges of system-wide performance, but may not indicate significant local or regional reliability problems. Regulators often do not require utilities to report statistics that could provide a better indication of significant but more localized outage problems.

The table below presents these indices.

Index	Description
SAIFI - system average interruption frequency index	The average number of sustained outages (defined as more than five minutes in duration), per year, per customer over a defined area such as a utility system or region.
CAIFI - customer average interruption frequency index	Among customers experiencing sustained outages, the average number of outages per year.
SAIDI - System average interruption duration index	The average length of a sustained customer outage, in minutes.
CAIDI - customer average interruption duration index	Among customers experiencing sustained outages, the average length of the outage.
MAIFI - momentary average interruption frequency index	The average number of momentary outages (defined as less than five minutes in duration), per year, per customer over a specified area such as a utility system or region.

3. NERC Regional Council Reliability Rule Violations

Recent violations include control area disregard for NERC and regional reliability council reliability requirements. Policy 5 by failing to properly rebalance load and consequently using emergency reserves as a prolonged source of supply rather than as a temporary relief measure.[1] In addition to NERC Policy 5, NERC regional council regulations are also violated more frequently. The East Central Area Reliability regional council (ECAR), whose members include 29 major electricity suppliers located in nine east-central states, published recent violations of ECAR Documents 2 and 3. Document 2 "establishes the minimum level of Daily Operating Reserves to be provided by each system," and Document 3, that "sets forth the actions to be taken by ECAR Systems in the event that initiation of emergency procedures is required, including equipment load reduction at member-owned facilities, reduction of distribution voltages, interruption of interruptible loads and dropping of firm customer load."[2]

1. NERC Policy 5 as defined in an East Central Area Reliability Council (ECAR) Executive Board letter to CINergy dated December 6, 1999. (www.ecar.org/news)
2. ECAR Document 2: Daily Operating Reserve, June 16, 1998.
   ECAR Document 3: Emergency Operations, June 16, 1998.

4. Glossary of Acronyms

BCHP	Building Combined Heat and Power
CAIDI	Customer Average Interruption Duration Index
CAIFI	Customer Average Interruption Frequency Index
CLR	Customer Load Reduction pilot program (in PJM)
DisCo	Distribution Company
DOE	U.S. Department of Energy
ECAR	East Central Area Reliability Regional Council
EEI	Edison Electric Institute
ESCO	Energy Services Company
FERC	Federal Energy Regulatory Commission
GenCo	Generation Company
IMEA	Illinois Municipal Electric Association
ISO	Independent System Operator
JITKA	Just In Time Key Accounts Program (in IMEA)
MAIFI	Momentary Average Interruption Frequency Index
MW	Megawatt
NERC	North American Electric Reliability Council
PJM	The Independent System Operator serving Pennsylvania, New Jersey, Maryland, Delaware, Virginia, and the District of Columbia.
POST	Power Outage Study Team (DOE)
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
TransCo	Transmission Company
UPS	Uninterruptible Power Supply

Sponsoring Organizations

ASCO Power Technologies

DTE Energy Technologies

Eaton Corporation

Elliott Energy Systems, Inc.

Enercon Engineering, Inc.

ENCORP, Inc.

General Electric

Howmet Corporation

Powel B2B Services, Inc.

Rolls-Royce plc

United Technologies, Inc.

Visteon Corporation

U.S. Department of Energy

For additional information contact:

Arthur D. Little, Inc.
Acorn Park
Cambridge, MA 02140
617-498-5000
www.arthurdlittle.com

Stan Blazewicz
Senior Manager

Stow Walker
Senior Manager

A