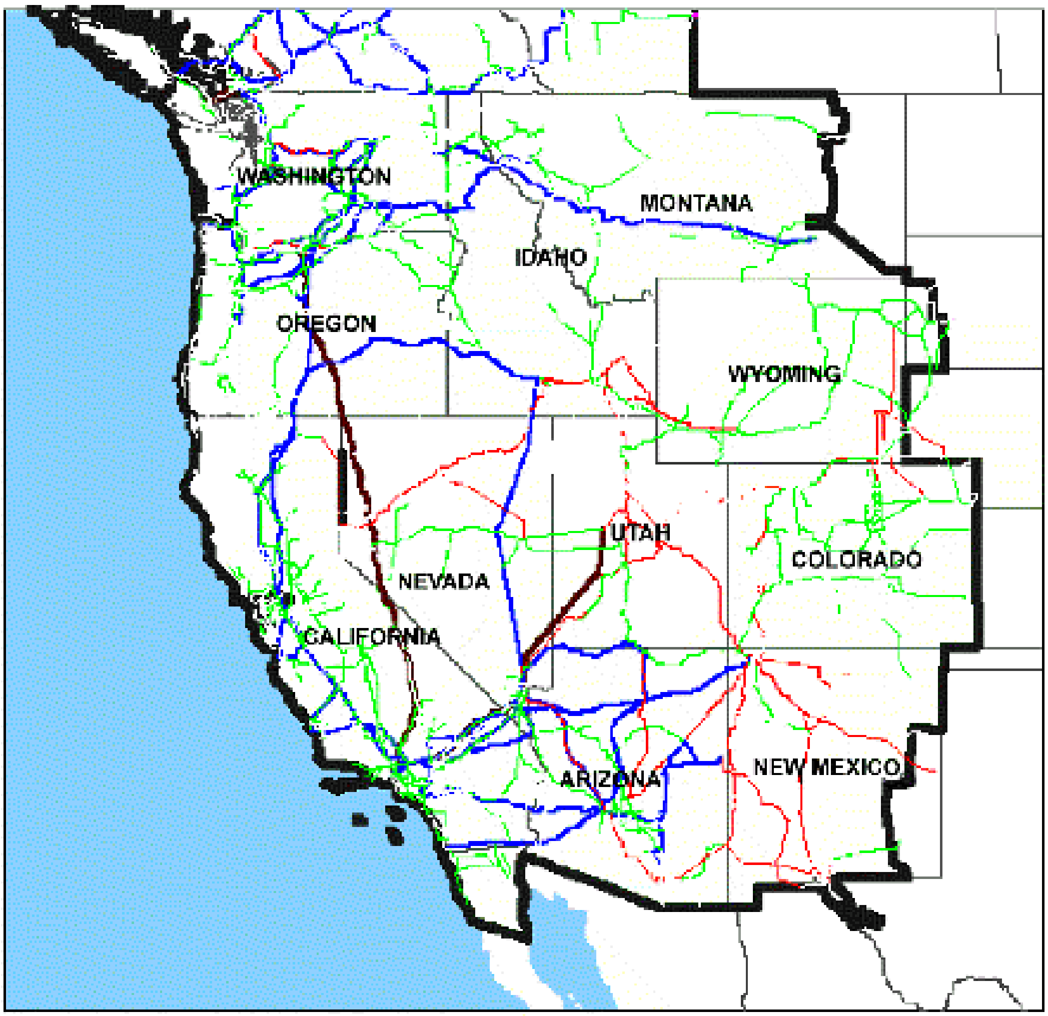
The Western States Power Crisis: Imperatives and Opportunities



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Executive Summary

The California power crisis is only the most visible part of a larger and growing energy problem in the U.S., resulting from more than a decade of inadequate investment in power generation, transmission, distribution, and customer demand-response programs. The solutions put forth thus far have not addressed the fundamental technology issues nor the risks to the economy imposed by chronic under-investment in electricity infrastructure. Already, the direct economic losses to the nation of power interruptions and inadequate power quality conservatively exceed $100 billion per year.

This White Paper summarizes a set of actions to help resolve the current power crisis, as well as the technological means to put the electricity infrastructure back on a solid footing capable of meeting the escalating power demands of the 21st Century.

Origins of the White Paper

Although the White Paper was prepared in the light of the California crisis, the roots of the document go back to several discussions of a much broader topic – the vulnerability of the North American power system – at EPRI's annual Summer Seminars. These Seminars are conducted with the EPRI Board of Directors and Advisory Council. Over the past two years, the Summer Seminar participants highlighted the disincentives to upgrade the power system infrastructure resulting from the current uncertainties in the institutional and market structure of the power system. Over a year before the California crisis exploded on the scene, the Summer Seminar discussions noted that the growing unreliability of power delivery, including the potential for major blackouts, placed at risk the benefits of electric utility restructuring and could provoke a damaging public backlash.

The Summer Seminars recommended that EPRI convene a national forum of private and public stakeholders focused on creating the infrastructure for the digital society. EPRI has undertaken this initiative with the objective of addressing the immediate issues posed by the California crisis, while simultaneously creating the technology base needed to build a robust power delivery infrastructure for the 21st Century. EPRI, as the national collaborative R&D leader in the power sector, is addressing the electric infrastructure needs by:

- Implementing a series of actions designed to help mitigate the near-term problems in California and the West.
- Informing policy makers on the science and technology opportunities and issues facing the new digital society.
- Developing and demonstrating the new infrastructure technologies, and supporting standards, needed to assure reliable electricity supply and enable the digital society. This requires an architecture that encompasses the convergence of energy and information delivery, as well as the convergence of markets and technology for electricity and gas.

This paper summarizes a series of specific technical recommendations needed to address the current problems of the Western States power system. In the spirit of moving forward, the recommendations offered are concrete and actionable. The scope is regional, the focus is on the integration of technology and policy solutions, and the goal is to ensure that society continues to be well served by the electricity infrastructure. Highlights of the recommendations are summarized in Table ES-1 following this section. The complete list of these recommendations is presented in Table 1-1, page 5, and discussed in the following sections of the paper.

EPRI discussed these recommendations with a diverse group of stakeholders from the Western region at the Western Power Solutions Workshop convened by EPRI on June 7-8, 2001. Joining EPRI as co-convenors of the Workshop were Carl Guardino, President, Silicon Valley Manufacturers Group; Roger Hamilton, Commissioner, Oregon PUC and a member of EPRI's Advisory Council; and Steve Hickok, COO, Bonneville Power Administration and a member of EPRI's Board of Directors. In addition to the convenors, Workshop discussion leaders included Michehl Gent, President & CEO, North American Electricity Reliability Council; T.J. Glauthier, President, Electricity Innovation Institute; and Terry Winters, President & CEO, California ISO. The Workshop participants (listed on page 62) recommended a broader policy framework to encompass the technology recommendations. This framework and related technology needs in the areas of Distribution Systems and Emergency Planning, Electricity Markets, Transmission Systems and Grid Operations, and Power Supply and Environment are summarized at the end of each corresponding section of this white paper.

What is the problem?

The basic problem underlying the California crisis has been a fundamental imbalance between the steadily growing demand for power and the limited increases in generation and transmission capacity during the 1990s. An inadequate market design, in which price signals were not available to moderate demand, exacerbated this supply/demand imbalance. Beginning in 2000, a combination of market forces and external events – including a hot summer, low water levels for hydro, high gas prices, above-normal number of plant outages, and rapid economic growth in areas like Silicon Valley, precipitated the California energy crisis, which now threatens to involve the entire Western region at the same time. The total cost for power in California rose from $7 billion in 1999 to $28 billion in 2000, and is projected by the California Independent System Operator (CAISO) to reach at least $50 billion this year.

Rolling blackouts in California are having both direct and indirect impacts on the state's economy. In terms of direct costs, estimates in the San Francisco Bay Area run as high as $1million per minute of lost economic output for high-tech firms. Indirect costs include the cumulative impact of rolling blackouts, such as the failure of small businesses, the movement of jobs and production out of the state and region, and intangibles such as the effect of power outages on public health and safety.

In all likelihood, California will be facing hundreds of hours of outages and rolling blackouts in the summer of 2001, a figure that could grow several-fold if power plants are unexpectedly forced off line, or if imports from the Northwest are further reduced. The Pacific Northwest part of the Northwest Power Pool is at least 3,000 MW short (on a planning basis) of historic reliability levels.

A major outage is not out of the question. Critical equipment, such as transformers, will be running at maximum capacity this summer. Failure of a single critical component could result in a major outage spreading throughout the Western Systems Coordinating Council (WSCC) at considerable cost. Based upon the experience of the August 10, 1996 outage in California, the cost of such a cascading outage could be billions of dollars.

What kind of power system is ultimately needed?

The Western region needs a comprehensive strategy to weather the current crisis and create a power system that meets the region's economic and social needs well into the future. Such a system would ensure that the public is free from the threats of rolling blackouts, able to count on stable and competitive electricity prices, and enjoy the benefits of new electricity-based services. However, the ideal destination is more than just restoring sound service; it also means following the path to a sustainable electricity infrastructure capable of supporting efficient electricity markets, attracting business to the region, and supporting productivity and economic growth in the emerging knowledge industries of the 21st century. The technology opportunities described in this paper also serve to establish the necessary power system infrastructure needed to serve the digital society.

Technologically, this will require an electricity system that combines central and distributed sources of power, with the capability to manage competitive transactions in an open access power delivery system, and to provide a growing array of services, including different levels of reliability and power quality at different prices. High-tech industries, for example, would be able to purchase readily very high levels of reliability when and where needed.

What actions should be taken near-term (2001-2002)?

A number of actions should be taken immediately to mitigate the impact of blackouts, and reduce the likelihood of a widespread power outage in the summer of 2001, or 2002. Those actions that involve capital equipment could take 6-18 months to fully implement, so it is critical that work start on them immediately. Top priority action items are listed here:

- Undertake comprehensive emergency planning for repetitive rolling blackouts, as well as for potential major outages. Preparation should include educational activities and advanced warning. (Note that the Governor of California has recently issued an order establishing an advance warning system.)

- Perform a comprehensive assessment of the health, safety and economic costs of rolling blackouts and power outages. The economic analysis should include both direct and indirect costs of lost production.
- Expand ongoing load management and energy efficiency programs to rapidly curtail demand during emergencies.
- Introduce time-sensitive pricing signals and demand-response enabling technology to all consumers of electricity, beginning with customers whose demands exceed 200kW.
- Ease restrictions on backup emergency generators to allow them to be used for load reduction during emergency conditions (Stage 2-3 Alerts).
- Improve maintenance practices in all parts of the electricity supply and delivery chain. Make better use of RCM (reliability centered maintenance) and diagnostic tools to most effectively manage the maintenance process. Integrate RCM recommendations with ISO planning of power plant availability.

What actions should be taken mid-term (2002-2003)?

There are a number of technology solutions that can address specific needs in the generation, delivery and use of electricity in the mid-term. They should be seen as parts of an integrated package of solutions that, together with new market design, would put the power system well on the path to restoring the supply/demand balance by 2003. Electricity cannot easily be stored in bulk, so the production and consumption of electricity effectively happens at the same instant. This reality imposes unprecedented requirements for technology integration among all parts of the system, from generator to customer, and over increasingly wider geographic areas. Some of the key action steps for the mid-term include:

- Repair dysfunctional wholesale power markets.
- Expand the ability of retail customers to engage with the marketplace, by introducing an array of pricing options, from flat rates to time-of-use tiers to real-time pricing.
- Upgrade the transmission system using advanced maintenance procedures, greater regional coordination of the grid, and advanced technology to increase the throughput of the existing lines.
- Accelerate the automation of distribution systems to improve service and reduce the severity of rolling blackouts.
- Upgrade existing power plants to increase their capacity by 5% or more through advanced diagnostic and maintenance procedures, plus cost efficient retrofits of key components.
- Expand the use and effectiveness of smaller, modular forms of distributed generation by accelerating their electrical interconnection to the grid, resolving environmental constraints, and streamlining the siting process for new units.
- Take advantage of the opportunities presented by the crisis to develop and demonstrate new generation technologies that increase efficiency and fuel diversity.

What actions should be taken for the longer term (beyond 2003)?

Longer-term objectives include transforming the current electricity infrastructure so that it is fully capable of supporting the rapid growth and diversification of the U.S. economy based upon the new knowledge-based industries. This will require a fully functioning, competitive marketplace for electricity and electricity-based services, plus the underlying infrastructure to support a competitive market. For both environmental and national security reasons, fuel diversity must also be vigorously pursued as a national and regional objective. Electricity is the equal-opportunity medium for energy (produced from all energy sources), and is thus the principal vehicle for ensuring fuel diversity in the future. Nevertheless, the great majority of new capacity being built in the U.S. and in the West is gas-fired. Some of the key action items for the longer term include:

- Undertake a risk assessment of long-term, U.S. reliance on gas-fired generation, along with an analysis of the value of risk management through greater fuel diversity.
- Introduce price signals and competitive market dynamics to all customers.
- Undertake regulatory reform of the distribution system to provide incentives for technology innovation, automation and accountability for R&D.
- Create a planning process to design power markets that afford better coordination of wholesale and retail markets.
- Accelerate development and deployment of energy efficient appliances, machines, industrial processes and buildings.
- Develop and implement a comprehensive architecture for the power system infrastructure that anticipates the rapidly escalating demands of the emerging digital society.
- Expedite the construction of new, higher-efficiency power generation. Some 40,000 MW of new capacity has been announced throughout the WSCC through 2007, but it is likely that some of this capacity will not be built. Financing concerns in the present climate of economic uncertainty, as well as siting concerns, could reduce this forecast. A comprehensive assessment of future capacity needs should be conducted to develop a strategy for regional generation additions.
- Accelerate R&D on advanced nuclear, renewables and coal-based systems to manage supply risks and balance the long-term fuel mix of power generation within environmental constraints.
- Establish a regional transmission agency with the authority for siting and installing new lines, upgrading existing lines, and allocating costs.

Note that very few of these recommendations can be implemented in the absence of an investment climate that encourages technology innovation. The uncertainties surrounding restructuring and continued use of regulated cost-plus investment returns have hobbled the flow of advanced technology into the electricity infrastructure. Regulatory reform should have as one of its principal objectives the stimulation and adoption of technical innovation.

What will this cost?

The electricity system is the life-blood of the $3+ trillion economy of the U.S. Western region. The cost to support and drive this economy must include a sound infrastructure. Some specific projections of cost include:

- Load management programs can be rapidly put in place at roughly $50/kW. A 5,000 MW program would thus cost about $250 million per year.
- The cost of bringing the regional transmission system back to a stable condition is estimated at $10-30 billion. An annual expenditure of $1-3 billion will then be needed to maintain this condition in the face of continued demand growth. Broad-scale implementation of flexible AC transmission systems (FACTS) can reduce these costs by approximately 10 to 30%.
- Generation expansion in the West will be upwards of $20 billion over the next 6 years, based upon the current plans for 40,000 MW of new capacity.

Next Steps

EPRI's immediate objective is to assemble the most effective synthesis of technological solutions to meet the needs of a competitive power market and to build awareness of the capability of advanced technology among policy makers in the Western region. This set of solutions has the additional advantage of furthering the longer-term transformation of the electricity system that is urgently needed to support the growth of the digital economy.

Next steps include:

- Presenting these recommendations to state, regional and national regulatory and administrative institutions for their consideration.
- Seeking collaborative funding and joint action for critical assessments and technology development activities. Critical assessments include benchmarking the full costs of power outages and power quality problems, as a point of reference for public/private investments in infrastructure.
- Informing the community of electricity stakeholders who participate in the technical opportunities to solve the immediate crisis while creating the foundation for the power system of the future.

Table ES-1. Key Technology Milestones

Issue	Recommendations/Milestones			Benefit/Value	Text Ref.
	2001 - 2002	2002 - 2003	2004+		
Comprehensive Emergency Planning	• Review O&M practices for rolling blackout conditions • Provide consumer information on probability and extent of rolling blackouts			Reduced impact of forced outages; improved community relations	p.10-13, 16-17
Demand Responsiveness Pricing	• Implement Real Time Pricing for large customers • Develop supply/demand forecasting techniques	• Implement Real Time Pricing for commercial and residential customers • Reduce cost of smart meters		Reduce wholesale price volatility by as much as 50%	p.23-24, 28
Market Redesign	• Define and align stakeholders on needed market improvements	• Create a unified wholesale and retail market • Exploit interdependencies of gas and electricity markets	• Standardized regional market information	Improve supply/demand balance	P26-28
Optimize Utilization of Existing Transmission System	• Implement Reliability Centered Maintenance • Empower NERC to establish mandatory reliability standards	• Develop power-flow-based technology for system reservations and scheduling (replacing contract path approach)	• Install FACTS on a broad scale to improve power flow and system reliability	Increase grid reliability and rated transfer capacity by 20-40%	p.34-36, 43
Optimize Utilization of Existing Generation Fleet	• Enhance maintenance practices and integrate with ISO scheduling	• Upgrade capacity of existing units		Reduce unplanned outages by 25-50%; add more than 3,000 MW of peak capacity	p.48-52, 58
Accelerate Distribution Automation	• Define specific automation requirements and opportunities for distribution systems	• Integrate distribution automation into design of distribution systems		Improved productivity, reliability and emergency response	p.13-14, 17
Expedite New Generating Plant Construction	• Define interconnection requirements and modifications for optimal systems	• Accelerate interconnection of new distributed resource generators with the power grid	• Introduce alternate generation technologies to reduce over-reliance on natural gas	Offset up to 10,000 MW of gas generation	p.53-55, 58
Develop Transmission Superhighway	• Identify bottlenecks and define the initial architecture of the transmission superhighway	• Begin construction of inter-regional transmission superhighway	• Continued construction of superhighway	Enable reliable, digital-quality service	p.36-37

Section 1 – Introduction and Recommendations

Purpose

This White Paper attempts to address the ongoing power crisis comprehensively – integrating technology solutions with considerations for both the short-term and mid-term. The scope extends beyond California to address the emerging power crisis in the U.S. Western Region, and many of the recommendations have applicability in throughout the U.S.

The recommendations in the paper build upon a set of technical actions proposed by EPRI to a group of diverse stakeholders in the Western region. The recommendations incorporate insights gained at EPRI's Western Power Solutions Workshop on June 7-8, 2001, where the participants developed a broad policy framework to encompass the technology solutions.

Understanding "The Most Complex Machine"

As soaring electricity prices and the threat of blackouts spread beyond California to engulf the Western United States in an escalating power crisis, the unique nature and technical complexity of the underlying power system continues to be generally ignored. Such a simplistic view – all too common in both the business and policy-making communities – was epitomized recently by *Wall Street Journal* columnist, George Melloan (4/25/01):

> Keep in mind that the electric power industry is an old and fairly simple business…. You build a building, install some turbines powered by water, steam or gas that make a big rotor spin and generate power. You then stretch some delivery lines. As demand increases, you install more generators.

In fact, the power business was never that simple. Because electric energy is difficult to store in bulk, and must be essentially produced and consumed at the same instant, power systems are woven into tightly interconnected and synchronized networks, requiring highly sophisticated controls. Considered as an integrated network, the vast North American power system has been called "the most complex machine ever built." In addition, because power supply must be available instantly to meet changes in demand, electricity is also the most volatile of all commodities – with prices subject to fluctuations caused by such diverse factors as heavy demand during hot weather, or diminished hydroelectric capacity due to reduced rainfall. Indeed, the restructuring of such a complex system is inconceivable without recent technological advances.

Because of the fine balance required of a single network extending over hundreds of miles and into every home and business, numerous technical requirements must remain properly coordinated after restructuring. Some of these requirements relate to maintaining an adequate physical infrastructure and its operation; others to ensuring sufficient investment in supply capacity and network infrastructure. While the growing economy depends critically on a system of well-functioning electricity infrastructure and markets, the performance of the system requires adequate investment in the underlying technologies. The central thesis of this white paper is that the present power crisis – most evident in the Western states but potentially a national problem – requires a fundamental reassessment of the critical interactive role of technology and policy in both infrastructure and markets. The paper's primary conclusion is that the best way to mitigate the crisis in the near term is to seek new opportunities to apply advanced technologies and analytical methods that can enhance infrastructure flexibility, improve market responsiveness, and strengthen the connection between them.

The Infrastructure Imperative

Since passage of the National Energy Policy Act (NEPA) of 1992, wholesale power markets have been largely deregulated and several states have taken steps to open retail markets to competition. As described in more detail in the next section, restructuring has failed to provide sufficient incentives to build needed generation facilities, increase transmission grid capacity, and provide customers with better ways of managing their electricity usage. Ultimately, reduced investment in the electric power infrastructure for more than a decade has caused an imbalance between electricity supply and demand.

A few key numbers illustrate the dramatic decline of infrastructure investment: During the decade from 1988 to 1998, total U.S. electricity demand grew by nearly 30% but the transmission network grew at only half that rate with likely greater mismatch in the future. The effect of inadequate infrastructure investment has been most pronounced in California, where rapid economic growth resulted in an 18% increase in peak electricity demand in just six years, between 1993 and 1999 – during which period the state's generating capacity increased by only 0.1%. Demand-side management (DSM) was also slighted, as California's investment in DSM programs dropped 45% at about the same time, resulting in additional electricity demand of about 1,000MW.

From an infrastructure perspective, the Western States have been a crisis waiting to happen. What it took to push California over the edge was a "perfect storm" of colliding events, including diminished rainfall in the Pacific Northwest, explosion of a gas pipeline in New Mexico, and an unusually hot summer and an unusually cold winter over much of the region during 2000. As a result, electricity prices rose throughout the West: from an average of around $30/MWh in 1999 to $100/MWh or more in 2000; and by January 2001, the price of a forward contract for power to be delivered in August had risen to $500/MWh. Meanwhile, the California Independent System Operator (CAISO) has concluded that the state is "facing an electricity shortage of unprecedented proportions" this summer, with a forecast mismatch between peak supply and demand as high as 3,700 MW. NERC, the North American Electricity Reliability Council, forecasts an even larger shortage of >5,000 MW during peak load conditions. The inevitable result will be blackouts, which are now expected to spread to other Western states.

The Market Imperative

The most fundamental cause of the current crisis is an imbalance between electricity supply and demand. Failure to maintain an adequate infrastructure and supply has been made more critical by reductions in demand-response programs during the restructuring of electricity markets. Under the previous market paradigm, vertically integrated utilities performed long-range planning under the scrutiny of regulators, who allowed a preset authorized rate of return on prudent infrastructure investments. The guiding principle was the "obligation to serve," which encompassed the whole electricity value chain from generator to customer meter. Under this regime, there was little incentive to promote enabling technologies, such as smart meters, that support demand -response programs.

Under the new market regime, utilities have been restructured into separate functional units, where market competition – rather than regulation – is expected to provide the necessary incentives for investments in supply and delivery systems. A fundamental problem in California, however, is that wholesale and retail markets have been decoupled and given separate guiding principles –market-based for one, and rule-based for the other. The inherent conflict has hindered incentives for investment, exacerbated by a pre-existing supply deficit.

The unique attributes of electricity make the design of well functioning markets a significant technical challenge that has generally been overlooked by policy makers. The California experience illustrates three of the most important market flaws. First, wholesale power was made too dependent on the spot market. Utilities had been required or strongly encouraged by regulatory policy to sell their fossil generation facilities, yet discouraged from locking in stable wholesale electricity prices through long-term contracts. Second, the wholesale market organization was fragmented by a poorly structured separation of the Independent System Operator (ISO) from the Power Exchange (PX). This separation allowed generators to bid only a portion of their capacity ahead of time into the PX, then reaping exceptionally high prices when the ISO was forced to buy power in real time to balance supply and demand. Third, retail prices were frozen, which meant that there was no way for rising wholesale prices to be moderated by reduced demand.

The result of these market flaws was skyrocketing wholesale prices that essentially bankrupted the state's utilities, which had to continue providing power to their customers at enormous losses. Eventually the state itself had to begin buying power for its citizens, but at a cost so high that California's own credit worthiness was eventually downgraded.

Technological Opportunities

A variety of technological opportunities are already available to help resolve the growing power crisis by providing near-term ways to strengthen the electricity infrastructure, correct market flaws, and re-establish the vital market-infrastructure connection. As described in succeeding sections of this white paper, these opportunities can be considered in four broad groupings:

- Section 2: Distribution Systems and Emergency Planning. Technology is available to improve maintenance practices, automate distribution functions to help mitigate the impact of rolling outages, and improve emergency planning.

- Section 3: Electricity Markets, Pricing and Load Management. Technology is available to assist with- market design, simulation of market dynamics, implementation of market-based pricing, load management, conservation, and risk-based portfolio management techniques.

- Section 4: Transmission Systems and Grid Operations. Technology is available to improve maintenance practices, increase throughput of power, and coordinate grid operations on a regional scale.

- Section 5: Supply and Environment. Technological opportunities exist to upgrade existing coal, gas, nuclear and hydro facilities for capacity expansion, and to improve maintenance practices to reduce forced outages and to integrate distributed power resources. New capacity expansion in the near-term is focused primarily on gas-fired combustion turbines, for both economic and environmental reasons.

Key Recommendations

A detailed summary of the technology recommendations and milestones of the White Paper is provided in Table 1-1.

Table 1-1 Key Recommendations

EPRI Recommendation	Benefit/Value	Date Avail.	Responsibility	Refer-ence
Review operations and maintenance practices for rolling blackout conditions.	Approximately 20% reduction in forced outages.	2001	Distribution companies, outage coordinators	pg. 9, 15
Provide near-term information on probability and extent of rolling blackouts to all consumers.	Minimize impact of rolling blackouts on consumers.	2001	ISO and Distribution companies	pg. 13, 17
Review adequacy of current response plans to continuous rolling blackout conditions.	Minimize health and safety impacts.	2001	Employers, including government and emergency response agencies.	pg. 12, 16
Integrate distribution automation into the design of distribution facilities	Meet needs of future economy	2002	Distribution companies, research organizations and equipment suppliers	pg. 13, 17
Review black start contingency plans and improve black start operating skills.	Ensure emergency response capability	2001	Distribution utilities, transmission owners and operators	pg. 14
Create incentives for employers to shift work hours and practices for rolling blackouts	Reduce peak electric demand and loss of productivity	2001	Employers, regulators, utilities	pg. 13, 16
Electricity Markets: Pricing and Load Management				
Implement real-time and time-of-use pricing for all customers with electric demands that exceed 200 kW	Reduce WSCC electric demand by approximately 1200 MW for an estimated cost of $60M	2001-2	State regulatory commissions or energy service providers	pg. 22, 29
Promote maximum energy efficiency and load management	Reduce WSCC electric demand by approximately 2700 MW at an estimated cost of $150M	2001-2	State regulatory commissions and planning agencies	pg. 24, 30
Promote the installation of interval metering with open communication protocols	Enable customers to better manage their electricity use, improve supply/demand balance	2002	Distribution utilities for installation, state regulatory commissions to insure cost recovery	pg. 23, 29
Develop supply/demand forecasting techniques	Improve supply/ demand balance, lower energy costs	2001-2	EPRI, U.S. Department of Energy, state energy planning agencies and commissions	pg. 27, 30
Repair dysfunctional wholesale markets	Establish competitive market places	2001-3	Regional transmission organizations (RTO), FERC	pg. 26, 28

EPRI Recommendation	Benefit/Value	Date Avail.	Responsibility	Refer-ence
Create a forum to better define the market-infrastructure interface issues	Improve understanding and definition of the technical issues in market design	2001	FERC should take the leadership in convening this forum	pg. 27, 29
Generate standardized regional energy information	Establish common benchmark for planning, improve interface between regional systems and markets	2004	RTO, EPRI, U.S. Department of Energy, state energy planning agencies and commissions	pg. 30
Transmission Systems and Grid Operations				
Implement a "whole system" Reliability-Centered Maintenance (RCM) capability; conduct equipment health assessment for the most vital components	Up to 20% reduction in forced outages	2001-2	All transmission owners, coordinated by the ISO and RTO	pg. 34, 43
Initiate comprehensive, region-wide transmission risk analysis	System-wide reliability improvements	2001-2	CAISO and related RTO's	pg. 40, 42
Establish mandatory reliability standards	To maintain and enhance reliability of the North American transmission grid	ASAP	Federal legislation required/empower NERC (NAERO)	pg. 40, 44
Create a seamless real-time exchange of information among regions	20-40% increase in power flows across Regions; enables secure operation of regional grids and markets	2001-2	FERC, RTOs	pg. 36, 43
Refresh and upgrade training for grid operation personnel	Ensures fastest system recovery under emergency conditions, reduces system outages	2001-2	All transmission owners, coordinated by the ISO and RTO	pg. 39, 43
Develop power-flow technology for system reservation and scheduling	Reduces and avoids transmission congestion and enables proper functioning of system-market interface	2002-3	NERC (NAERO), RTOs, EPRI	pg. 40, 42
Establish regional authority for siting and cost sharing	Regional transmission planning; create transmission backbone	2002-3	FERC, RTOs	pg. 40, 44
Begin integrating dynamic thermal modeling technologies into the state-wide grid operation systems	10-30% increase in power rated transfer capacity	2001-2	All transmission owners, coordinated by the ISO and RTO	pg. 35, 42
Begin aggressive transmission upgrade program	20-50% increase in rated transfer capacity	2001-3	All transmission owners, coordinated by the ISO and RTO	pg. 36, 42

EPRI Recommendation	Benefit/Value	Date Avail.	Responsibility	Refer- ence
Begin nationwide installation of Utility Communication Architecture (UCA)-based digital communications and a Web-based monitoring and diagnostics system	Open access to information; decrease in time required to respond to and recover from blackouts	2001-2	All transmission owners, coordinated by the ISO and RTO	Pg .36, 43
Widely install Flexible AC Transmission Systems (FACTS)	Increase grid reliability and rated transfer capacity by 20-40%; lower capital expenditures by 20-40%	2004	All transmission owners, coordinated by the ISO and RTO	pg. 37, 42
Develop interregional, high-capacity, transmission super highways	Reduce regional vulnerability to supply/demand imbalance	2004	FERC and DOE	pg. 36
Supply and Environment				
Upgrade Capacity of Existing California Fleet				pg. 48, 58
- Fossil Steam Units	500 MW add'l capacity	2002-3	Power Generators	
- Combustion Turbines	200-500 MW of peak generating capacity	2002-3	Power Generators	
- Nuclear Plants	~100 MW add'l capacity	2002-3	Nuclear Plant Operators	
- Cogeneration	600 - 800 MW in CA	2002-3	Wind Plant Owners	
- Biomass (assure adequate -fuel supply)	700 MW of existing biomass available	2001	Biomass Plant Owners U.S. DOE	
Integrate Maintenance Scheduling with ISO operations	Reduce unplanned outages during peak periods by 25-50%	2001-2	Plant Operators ISO	pg. 51, 59
Accelerate Interconnection of Distributed Resources Systems	Connect 500-1000 MW of DR to the grid in CA	2001-3	Power Producers Equipment Vendors Regulators	pg. 51, 60
Increase use of clean emergency backup generators	Up to 500 MW of added capacity during peak periods	2001-3	Equipment Vendors, Customers, Regulators	pg. 52, 57
Create Process for Regional Planning of Capacity Additions	40,000 MW of new capacity by 2007	2002-3	Project Developers Regulators WSCC, ISO	pg. 54
Develop alternate generation technologies to reduce over-dependence on natural gas	Offset 10,000 MW of future gas generation additions in California	2001-5	Equipment Vendors Research Orgs. Business Developers Power Generators Regulators	pg.55, 59

Section 2 – Distribution Systems and Emergency Response

Summary

This section discusses what can be done to minimize the adverse impact of the immediate power crisis on all members of society. Issues and actions presented below focus on the two major impacts of the present crisis: 1) frequent rolling blackouts lasting a few hours or less, and 2) state-to-regional-scale blackouts lasting up to a day or longer. Specific recommendations are provided in five broad areas:

- Provide improved forecasting and advance notification of rolling blackouts.
- Improve outage response plans to reduce peak loads.
- Assess the direct and indirect economic costs of extended rolling blackouts.
- Improve maintenance of the distribution system to meet the stress of outages.
- Automate the distribution system to provide improved reliability of productivity

Introduction

Deregulation has changed the role of the electric utility. In the past, a traditional vertically integrated monopoly utility operated under the "obligation to serve." In a power crisis, utilities would command all part of the power infrastructure to keep the lights on, manage unavoidable outages, and minimize operations and maintenance costs to the company and consequential costs to customers. At some point in the future, utility companies may operate under an unambiguous market-based "incentive to serve," rather than this historic obligation to serve.

<u>In the current transitional state, however, the obligation to serve is in doubt, and the incentives to serve are still uncertain</u>. In California, for example, distribution utilities still operate under an obligation to serve rule; yet, divestiture has removed their direct control over the resources needed to serve.

The need of society for reliable electric power is greater than ever. Means must be found to manage the present power crisis, to keep the lights on to the extent possible, and to minimize the impact of blackouts. All members of society have a stake in the outcome of the decisions being made. Government agencies, distribution utilities, industry, commercial companies, and residential customers – all have a role to play.

Because all society is involved, energy education – public and private – will be key to minimizing the impact of the present power crisis. The role of education includes improving communications with all stakeholders to help reduce or avoid blackouts as well as managing them when they occur. At the same time, new products and services can help meet the particular needs for power reliability (and power quality) for critical customers.

In many parts of the U.S., the distribution system is now old, obsolete and in need of replacement. The obsolescence is quickening with the rapid pace of technological change in the digital microprocessor-driven economy the distribution system must now support. With new forms of distributed generation and advances in information technology coming into prominence, the architecture of the distribution system of the future is up for grabs. As yet, however, there is no agreement on what the distribution system of the future will or should look like. One conclusion emerging from the workshop participants is the need for regulatory reform of the distribution utility to implement the latest technology. This includes an analysis of the cost structure of the distribution system, incentives to apply innovative technology, and clear R&D accountability.

Outage Management

Outage management addresses efforts before, during, and after an outage. The management approach differs for the two major types of problems possible with the present crisis: rolling blackouts of a few hours or more, and state-to-regional-scale unplanned outages lasting up to a day or longer. Each type of problem is discussed separately below.

Rolling Blackouts

In 2001, electricity supply shortages in California have already resulted in rolling blackouts throughout the state, and further outages are expected this summer. These blackouts are managed by local distribution companies at the request of regional grid operators (in California, the Independent System Operator or ISO) when power demand threatens to exceed supply; the rolling blackouts serve to shed load strategically in order to prevent local or regional grid collapse. The localized outages typically last for one-to-two hours depending on the distribution utility and shut down a predetermined block of the distribution system; if needed, the outage is then shifted to the next block, and so on.

Although distribution companies will be able to make certain technological improvements in time to help operations during the present power crisis, education and communication will be key to minimizing the overall societal cost of the impending rolling blackouts. In the long term, implementation of distribution automation technology ultimately will minimize the frequency and impact of rolling blackouts, as well as improve their overall operational effectiveness.

Rolling Blackouts and Distribution Companies

Historically, one of the time-honored roles of the distribution company was to restore power as quickly as possible following system outages. In today's power crisis, however, the distribution company is being asked to play a very different role, one that is focused on blackout management. Shutting down power, rather than restoring power, not only runs against the grain and long-term training of distribution employees, but it puts them in the line of fire. Although the divested distribution company is not the source of the blackout, they are seen as responsible by their customers, and are typically the first to feel customer wrath and field customer complaints. Circumstances require them more than ever to help their customers and their community weather the power crisis. Distribution utility tasks include not only the actions involved in switching power off and on, but also include working closely with local governments to ensure that:

- critical public services are maintained,
- the outage management process is administered fairly and equitably, and that
- public communications provide sufficient advance notice to the community to allow them to prepare for downtime.

Because few distribution facilities are automated, most rolling blackouts will require a sizable workforce in the field to operate equipment until automation is complete. The employees must be dispatched to the switch location in *anticipation* of a blackout. Once at a location, they may be required to wait extended periods of time before they actually open the switch (which ultimately may or may not be required by the grid operator). Distribution system maintenance may suffer in the meantime because utility employees are being diverted from performing the planned maintenance for which they were employed. Also, employee safety risks may be greater, both from operational hazards as well as from customer-created hazards such as back-feed from onsite backup generators.

Distribution Facilities

Maintenance of certain critical portions of the distribution system takes on greater importance during prolonged periods of rolling blackouts. Distribution system facilities, in particular distribution feeder breakers, are operated more frequently in extensive rolling blackouts (as often as once a week, as opposed to a few times a year or less under normal circumstances), stressing the equipment, and increasing the probability of equipment failure. As a result, maintenance requirements will increase. Many utilities have adopted a Reliability Centered Maintenance (RCM) philosophy and practice, to identify the most critical components and lay out an optimum schedule for repair or replacement. Advances in RCM are based on new technology, including remote sensors and data acquisition systems to determine machine condition and assess maintenance needs without removing the equipment from service. This approach pinpoints equipment threatened by impending failures and makes recommendations for removal of equipment for service. More information on RCM is contained in Section 4 of this report.

Communications and coordination with the grid operator or ISO are increasingly important for distribution companies during the power crisis. Utilities and the ISO can use RCM as a tool to determine critical maintenance needs of highly stressed equipment and schedule maintenance even during “no touch” periods, if needed to prevent a catastrophic in-service failure.

Minimizing the Consequences of Blackouts

During rolling blackouts, distribution companies and government officials must integrate power system operations with critical social needs. Among the highest priority needs are preserving public health and safety and minimizing economic losses.

Health and Safety

Emergency service providers such as hospitals, police, and fire stations are exempted from rolling blackouts, which, because of the lack of spot-control and automation on distribution systems, also means that customers who share a circuit with a critical load will not lose power either. In northern California, nearly half of all customers are spared rolling blackouts because of this lack of control. In California, the CPUC also excludes underground public transportation, such as BART, from exposure to rolling blackouts. However, there has been at least one case during the recent series of rolling blackouts in which a hospital's power was inadvertently shut off. This incident speaks to the need for blackout-related training of distribution system workers, and to the importance of developing automated distribution systems.

For individuals, health issues from rolling blackouts focus primarily on the ill and infirm. Heat stress can be deadly for elderly customers (especially as rolling blackouts are most probable on the hottest days, when electricity demand is highest); others rely on electricity for home life- and health-support systems. Although most hospitals have emergency generation and may be exempt from rolling blackouts, very small hospitals, rest homes, hospices, assisted care and other facilities may not have backup generation nor be exempted from blackouts.

Life-safety issues include traffic management, security system integrity, personal security, loss of HVAC systems, and potential loss of telephone access. State and local agencies and distribution utilities should review policies in these areas and consider various technological solutions. For example, concerns about traffic safety and congestion during outages can be addressed by cities by exploring installation of solar-powered, battery-powered, or other backup traffic signals at critical intersections.

Economic Losses

The economic consequences of rolling blackouts for commercial and industrial businesses include lost productivity, loss of product, lost sales, damage to equipment, time and cost of recovery, lost market share, lost customer good will, and lost competitiveness in global markets. As discussed in Section 3 of the report, these costs are believed to be very high, but they are difficult to quantify.

Utilities can work with commercial and industrial customers to minimize the impact of rolling blackouts through load management techniques (discussed in Section 3 of the report) and in some cases by using distributed resources to provide on-site generation (discussed in Section 5).

Regular rolling blackouts extending over a long period – weeks to months – will likely have an impact that is greater than that predicted by simply adding up the expected impact from a equal total of isolated power outages. During long periods of rolling blackouts, various issues that are not important for infrequent outages will compound into new problems. For example, businesses may be forced to close because of inability to absorb continuing losses from repeated episodes of daily rolling blackouts. While all businesses can tolerate occasional brief outages, the more frequent the outages, the more businesses that will incur losses. Small businesses are particularly susceptible because they lack the financial reserves of larger companies. In fact, about 40% of small businesses fail following a local natural disaster. Extended periods of rolling blackouts will have a similar effect.

In addition, many energy-intensive processes that are not critical on an everyday daily basis, such as water pumping and fuel pipeline operations, are not allowed by California State Law to operate under Stage 3 (and for some processes, Stage 2) power crisis conditions. Backlogs can develop that severely impact health and safety (e.g. possible lack of irrigation or drinking water) and economics (e.g. lack of fuel at critical facilities such as airports and shipping terminals). In extreme cases, oil refineries unable to ship processed fuel can run out of storage capacity and be forced to curtail operations or shut down, causing significant spikes in fuel costs at a time of already record fuel prices. Such cases are real: California already approached these conditions during recurring rolling blackouts in January 2001.

For distribution utilities, extended rolling blackouts can take an economic toll. Distribution switching equipment will be heavily used for days on end, while at the same time system-wide maintenance will be deferred for lack of crews or "no-touch" periods. Failures will increase, adding the problems of unplanned outages to semi-planned rolling blackouts.

Customer Preparedness

The impact of rolling blackouts can be reduced by effective customer preparedness measures. Utilities and other organizations have developed guidelines on preparing for blackouts. Many of the recommendations repeat the common sense measures of preparing for any emergency (keep flashlights, battery-powered radios, a non-electronic telephone, and a first aid kit on hand; maintain a stock of bottled water and nonperishable food; etc.) However, other recommendations are specific to power outages (safe use of an uninterruptible power supply or standby generation, backup power for medical systems, etc). Basic public information on how to prepare for rolling blackouts should be disseminated broadly across the population, much like earthquake preparedness and Y2K information has been provided. Additional synthesized information about the possibility and impact of outages is required by organizations that need to plan ahead for rolling blackouts, from municipalities to public safety organizations to private companies

A second – and perhaps more important – aspect of customer preparedness is advance notification of upcoming or anticipated power outages. Most of the impacts of an outage can be better managed with timely information about the blackout. In the near term, manufacturers and commercial customers could use information about the probability of an outage to schedule employees and critical operations to minimize the economic loss. Companies could design alternative work plans, including split shifts, early starts, telecommuting, etc. Agricultural interests might be able to negotiate alternate times (e.g. for irrigation) given advance warning of an outage. In the past, some utilities have not disseminated such rolling blackout information because of concern for public security, but in the present crisis, the benefits from public knowledge may well outweigh any public security concerns. Recognizing these concerns, Governor Davis of California has recently directed the ISO, the Office of Emergency Services, and the Energy Oversight Board to work with the utilities to build a proactive notification system. This system provides not only a 1-hour advanced warning before a blackout could occur, but also includes 48 and 24-hour notices that blackouts might happen due to predicted hot weather conditions, a lack of energy supply, or planned and unplanned maintenance at generation facilities. This proactive approach will include a system by which residents and employers can have their extensive contact information such e-mails, pagers, and cell phones listed in a database. All contacts can receive a 48, 24 and 1-hour automatic notification in advance.

Longer-Term Technology Opportunities

Ultimately, automation of the distribution system will provide the framework for improving its reliability, and reducing the cost of grid operation. The present power crises, with the need for constant manual operations to support rolling blackouts, is spurring implementation of automation at the distribution level, just as the 1965 New York blackout led to universal implementation of SCADA (Supervisory Control And Data Acquisition) systems at the transmission level.

Distribution automation was initially proposed because it is essential to creating a power system that adequately can support the digital economy of the 21st century. Now, in the midst of a power crisis, we are learning that accelerated implementation of some aspects of distribution automation can expedite the effort to improve short-term system reliability and realize the full benefit of real-time pricing and other market innovations. In addition, a utility with an automated distribution system would have the capability of automatically, economically, and selectively switching critical customers to alternate circuits, speeding power restoration, or shifting the impact of the outage to less-critical customers. This capability would also enable rolling blackouts to become more effective and strategic, by reducing the necessity to serve large numbers of customers who share a circuit with critical services such as hospitals due to lack of circuit control.

However, the development of the open communications system needed to allow for widespread implementation of distribution automation equipment is not complete. Additional funding can accelerate communications development as well as that of other distribution automation technology, and also provide interim benefits to alleviate the power crisis over the next two-to-three years. With adequate funding, the combination of smart meters, automated distribution and open communication architecture could be made available within 5 years. This would not only transform the electricity distribution system, but the entire electricity business by bringing the customer fully into the electricity marketplace.

Major Outages

In addition to the near certainty of semi-planned rolling blackouts in California for summer 2001 and 2002, the present power crisis raises the possibility of larger-scale unplanned blackouts that shut down some or all of the Western power grid for up to a day or longer. Although such extended blackouts are not likely, the magnitude of such events requires assessment of impact and mitigation measures. Contingency plans suitable for one-to-two hour rolling blackouts may not adequate for day-to-week long regional blackouts.

Emergency Power

Emergency power and fuel reserves suitable for intermittent and/or light-duty use during rolling blackouts may not be adequate for extended blackout conditions. In particular, generators may not be rated to meet longer-term power needs beyond emergency lighting and equipment shutdown, and fuel supplies may become exhausted. For critical facilities, arrangements should be explored for replacement equipment through rental companies or other organizations in case of generator problems during an extended blackout. Note that in California and many of the other western states, many critical service organizations such as fire departments are already required to maintain extended fuel supplies for use after an earthquake.

Extended Blackouts and Disaster Response Plans

For the extreme case in which a regional blackout extends beyond 24 hours, it is assumed that the National Guard, OES, Red Cross, FEMA and similar disaster response organization will begin to provide lifeline services along existing disaster response plans. These plans should be reviewed for the extended blackout case to identify any special considerations. Federal agencies should allocate greater resources to those geographical regions that are most likely to be affected.

Black Start Following an Extended Outage

Restoring the power grid after a complete regional collapse – a "black start" – can be a difficult process. Typically for a black start, power is restored first to local regions and then these regions are connected one to another until bit-by-bit the entire grid is operating together. As a result, different locations will have power restored at different times. The entire process can take many hours, and may involve additional aftershock-like local blackouts.

Retirements and utility downsizing have reduced the industry experience base, leaving little hands-on knowledge about black starts. Education in the form of training and simulation will be critical to the reliable and fast restart of the grid following a regional power collapse. Consequently, it is important that grid operators refresh their understanding of emergency procedures in the present grid environment.

Workshop Conclusions

In their discussions, Workshop participants emphasized the importance of providing adequate incentives for investment in the distribution system infrastructure. Previous EPRI studies of utilities nationwide have disclosed a consistent pattern of under-investment in both infrastructure upgrades and maintenance, and participants noted that many distribution systems are becoming old and obsolete. Because the economic risk of continued blackouts has become "intolerable and avoidable," they also supported legislation and regulatory directives that would provide incentives for technology development and establishment of new industry "best practices" for distribution systems. In addition, it was recommended that distribution utilities establish specific plans to incorporate advanced technologies into their system upgrade plans.

The Workshop participants concluded that distribution utilities should work more closely with state and local emergency to assure public health and safety during both rolling blackouts and possibly severe regional outages. As part of this effort, it was recommended that utilities specifically train their system operators in how to handle abnormal system conditions, such as blackouts.

In addition, the Workshop participants recommended the following actions that incorporate EPRI's technical recommendations.

Workshop Actions

Recommendation 2A: Improve Distribution Equipment Maintenance

Description: Review maintenance practices for distribution system operations during rolling blackout conditions. Review maintenance for distribution equipment that may be operated more frequently, or be more critical to system operations, during rolling blackouts.

Benefits: Improving the overall maintenance of the distribution system is key to ensuring reliability during the stress imposed by blackout operations.
Technology Milestones: 2001-2002: Implement reliability-centered maintenance.
Implementation: Utilities will need to work closely with outage coordinators to prevent "no touch" days from interfering with critical points in the maintenance process when imminent component failure is likely.
Barriers: Cost of the new diagnostic equipment and information software represents a barrier, particularly if cost recovery is not certain. A shortage of trained operators is also a barrier.
Overcoming Barriers: The barrier can be overcome by recognition that ultimately the cost of proper maintenance or the cost of system failure will be borne by the ratepayers.

Recommendation 2B: Improve Outage Planning

Description: Develop outage response plans that include: a consistent definition of a "triggering event" that starts the load dropping schedule; review of the adequacy of current response plans to repetitive rolling blackout conditions; the development and distribution of customer preparedness information; and a comprehensive assessment of impact of power outages on the local, state and regional economy.
Benefits: Better preparation and more robust response plans will help minimize health and safety impacts, including preventing the disruption of vital public services.
Technology Milestones: 2001-2002: Review and improve O&M practices for rolling blackout and outage conditions; Provide customers with advanced information on probability and extent of rolling blackouts.
Implementation: Utilities will need to review policies and practices in conjunction with State regulatory agencies and energy administrations, emergency services, consumer groups and trade associations.
Barriers: Cost and emergency priorities stand in the way of implementing better response plans.
Overcoming Barriers: Recognition of the urgency of the power crisis, and that the costs will be borne by the general public, as rate payers or as taxpayers, should help to move the process forward

Recommendation 2C: Create Customer Incentives for Load Reduction

Description: Provide incentives to encourage employers to review work practices and work hours to shift the time of their operations, reschedule workflows, allow telecommuting, and encourage other changes that reduce load during peak times.
Benefits: A significant response by a number of employers might be sufficiently large to reduce peak load at critical times to avoid a rolling blackout. This would reduce loss of productivity and the secondary effects of lost business.
Technology Milestones: 2001-2002: IT and broadband communication allowing workers to adjust work schedule to curtail loads and shift demand peaks. 2002-2003:introduce low cost 2-way metering systems.
Implementation: Regulators, utilities, and local employers would need to agree upon financial incentives for employers to reduce load, and would need to provide advance warning, preferably 24 hours ahead.
Barriers: Cost, disruption of work routines, and employee resistance would be significant barriers, as would creating sufficient incentives to have an employer be the first to curtail load.
Overcoming Barriers: Recognition of the true cost of outages on local and regional businesses would help to motivate employers. Compensation could help overcome employee resistance.

Recommendation 2D: Provide Realistic Outage Forecasts

Description: Provide near-term information on the probability and extent of outages, possible outage timing, and rotating block schedules.
Benefits: With advance warning, business and industries can adjust their workflow, minimizing lost productivity and market share. Public safety can be better protected.
Technology Milestones:
2001-2002: Develop probabilistic risk assessment to forecast likelihood of outages.
2002-2003: Use results of complex interactive network studies to improve accuracy of forecast.
2004+: Use massively parallel computational methods to predict system dynamics and load forecast in near real time.
Implementation: ISOs or other control area operators would have to factor forecasting into their operational practices, and work closely with mass media, emergency services and utilities to communicate up-to-date forecasts.
Barriers: System cost and the complexity of forecasting could be barriers to implementation, as would problems associated with inaccurate forecasts resulting from a sudden, unpredictable turn of events. Utilities may be reluctant to provide advance blackout information because of liability concerns, e.g., if advance information is used by criminals to plan robberies in blacked-out areas.
Overcoming Barriers: Recognition of the economic value and public safety benefit of day-ahead or week-ahead forecasting can help justify the cost.

Recommendation 2E: Accelerate Distribution Automation

Description: Integrating advanced technologies into the design, control, and operation of distribution facilities would help support and sustain the rapid growth of the digital economy, and help prevent blackouts.
Benefits: Upgrading the distribution system will be critical in meeting the needs of the future economy, where microprocessor-based intelligence will be embedded in every tool, appliance and machine.
Technology Milestones:
2001-2002: Define specific automation requirements and opportunities for distribution systems.
2002-2003: Integrate automation into design of distribution systems; accelerate use of distributed generators and storage systems (see Section 5).
Implementation: Distribution utilities should work with equipment suppliers, regulators and customers to design the distribution system of the future.
Barriers: The lack of financial incentives continues to be a major barrier to the rapid adoption of new technology in the distribution system, along with uncertainty during restructuring over who has the accountability for R&D.
Overcoming Barriers: Regulatory reform can set the stage for financial incentives, performance-based rate-making, distribution system cost analysis, and increased R&D investment.

Section 3 – Electricity Markets, Pricing and Load Management

Summary

This section examines the role technologies play in markets and their underlying infrastructures, with emphasis on how a combination of factors can produce the sort of price volatility, lack of infrastructure investment, and supply-demand imbalance seen recently in California. These factors are not unique to California, and if other states in the Western Region and the rest of the country wish to avoid repeating the California syndrome[1], they will also need to pursue the action items identified in this section. Specific recommendations are provided in four broad areas:

- Repair dysfunctional wholesale markets
- Enable retail markets to benefit from market restructuring
- Support public benefit programs to overcome market barriers to efficient use of energy
- Generate standardized regional energy information and forecasts

Introduction

A fundamental weakness of the transition in California is that wholesale and retail markets were de-coupled, and customers were never fully engaged in the new, more competitive paradigm. In particular, customers received no market signals to encourage demand response, and did not have the opportunity to take advantage of new pricing and service opportunities, such as time-of-use rates and contracts to sell "megawatts" (reduced demand from unused load) back to suppliers. Further restructuring of markets will require the application of several different types of technologies on both the supply and demand sides to enable full customer participation in the marketplace.

Electricity is unique among energy commodities because of the difficulty of storing it in bulk. Instant-response storage units such as batteries, for example, have very limited capacity, while pumped hydro storage is large but involves a long response time. In general, supply/demand equivalence requires very complex and long-lead-time infrastructure planning. As a result, the interrelationship between market and infrastructure is undergoing a more fundamental transformation than those that have affected most other industries undergoing deregulation.

Before the industry can make a complete transition toward a viable new market structure, a coordinated planning mechanism is needed to ensure adequate investment in generation, transmission, and load management. The most basic problem in the California

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[1] Ahmad Faruqui, Hung-po Chao, Vic Niemeyer, Jeremy Platt and Karl Stahlkopf, "The California Syndrome", Power Economics, May 2001, Vol. 5, Issue 5, pp. 24-27 .

crisis was that declining investment in these infrastructure components led to a fundamental imbalance between growing demand for power and an almost stagnant supply. This imbalance had been in the making for many years and is prevalent throughout the nation, as shown by Figures 3.1 - 3.4.

Generation Capacity Margin in North America

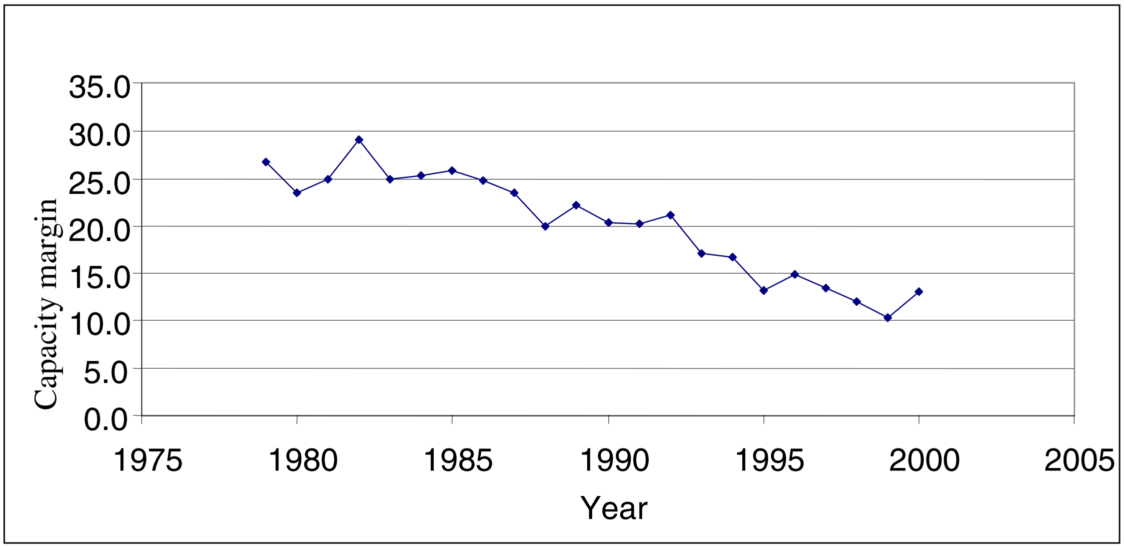
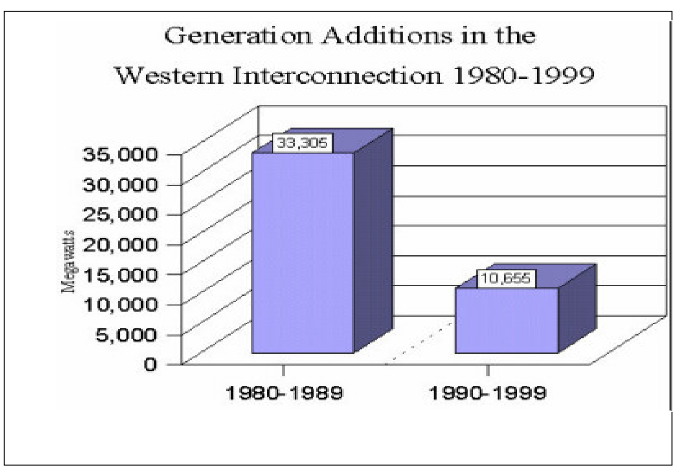


Figure 3.1

Generation Additions in Western U.S.



Source: Western Governors' Association

Figure 3.2

Transmission Additions in U.S.

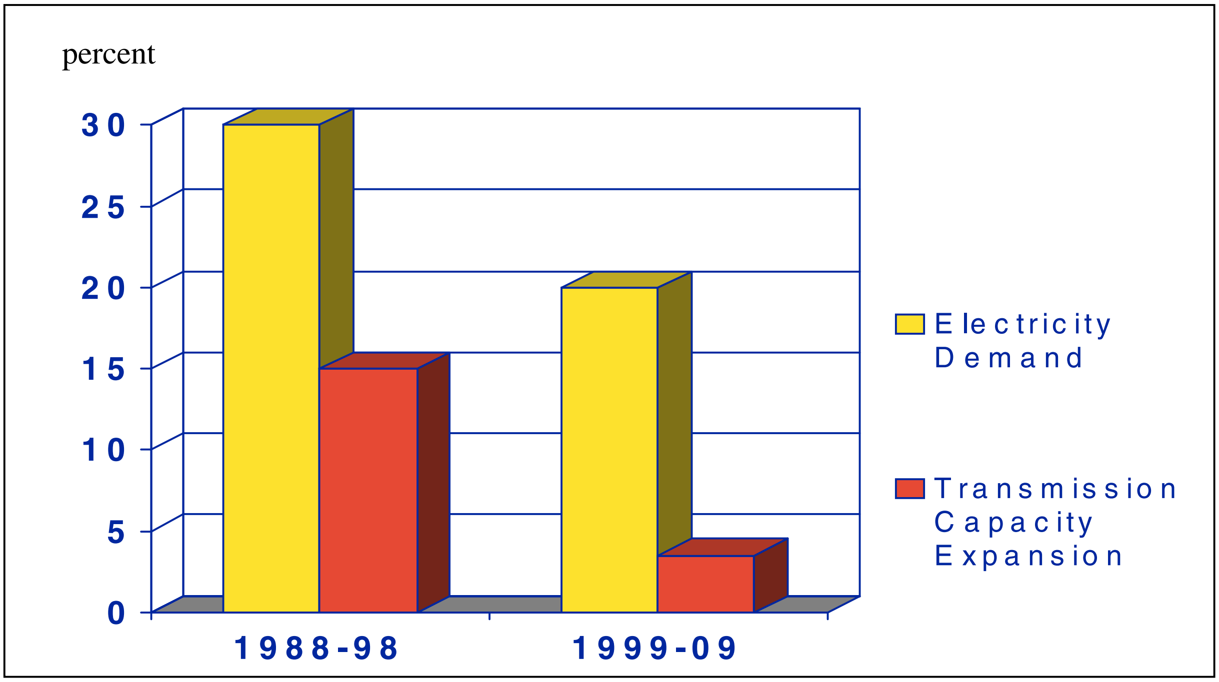


Figure 3.3

Electric Utility Demand-Side Management Expenditures

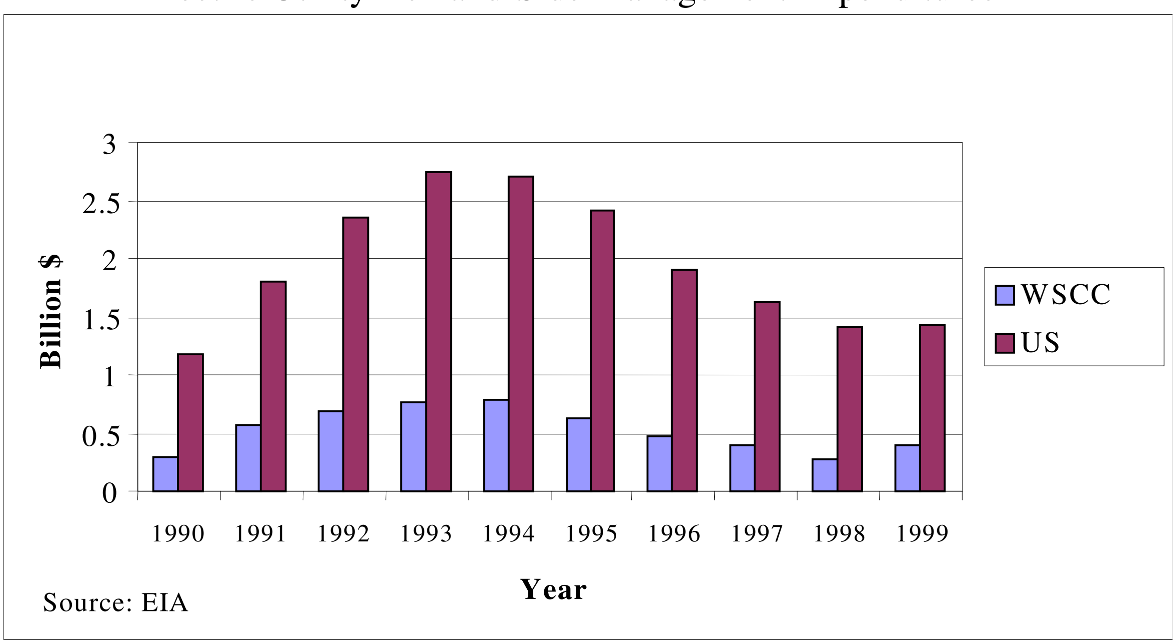


Figure 3.4

In addition to declining investment, a variety of other concerns must also be addressed:

- A lopsided fuel mix exacerbated the imbalance between electricity demand and supply in California. The generation mix in the state is heavily weighted towards hydro and natural gas generation. (Based on nameplate capacity ratings, hydro accounts for about 25% and natural gas for about 50% of total installed capacity.) Such an imbalance underscores the importance of supply portfolio risk management and a public policy that recognizes the strong interdependency between electricity and gas markets.
- The California situation was also made worse by problems spreading across interconnected energy markets. In particular, the unbalanced fuel mix linked California's electricity market closely to the natural gas markets. About half of California's annual production of electricity is generated by gas. Therefore, a significant increase in natural gas prices during the course of the year 2000 caused a commensurate increase in electricity prices.[2]
- The details of the market design exacerbated the demand-supply imbalance in California. When California was hit by a combination of external events, the design showed its many vulnerabilities:
  - The market transition overly depended on a spot market.[3]
  - The market organization was fragmented.
  - The market rules lacked incentives for either demand-side participation or provision of sufficient capacity.

Partly due to frozen retail rates and lack of incentives for utilities to pursue innovative pricing programs, demands were bid without any price elasticity. Thus, the market saw a vertical, completely price-inelastic demand curve. When a vertical demand curve (say, with high load) and a vertical supply curve (say, with low capacity) do not intersect or even lie close to each other, it leads to a condition known as the "last man bidding" problem. In other words, suppliers are rewarded for holding their bids off the market until the last minute, when buyers are desperate. When this occurs, non-competitive behavior would arise under any auction design, whether uniform or pay-as-bid, causing the market to break down.[4]

The combination of these features produced significant price volatility and irregularity. California's power market design needs to be reevaluated in light of supply scarcity and interdependence among energy markets.

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[2] Natural gas prices at the Henry Hub in Louisiana escalated from their historical value of around $ 2 per MMBtu in January to $10 per MMBtu in December. In California, they rose briefly to $ 50 per MMBtu in late fall, before coming down to $15 per MMBtu at year-end, still substantially higher than the national level.

[3] After investor-owned utilities sold off their thermal capacity, all power had to be sold and bought in a spot market, at least for the transition period before the stranded costs are fully recovered.

[4] Some have mistakenly faulted the uniform auction design for causing this problem. For a discussion, see Alfred E. Kahn et al., "Pricing in the California Power Exchange Electricity Market: Should California Switch from Uniform Pricing to Pay-as-Bid Pricing", California Power Exchange, January 23, 2001 and Alex Henny, "The illusory politics and imaginary economics of Neta," Power UK 85, March 2001.

Macroeconomic Impact of Higher Energy Prices and Power Outages

California's total expenditure on wholesale electricity purchases increased four-fold between 1999 to 2000, from $7 billion to $28 billion, and is projected to rise to at least $50 billion. Based on the prevailing forward electricity prices, the total electricity expenditure for just the summer of 2001 (from June to September) would reach $33 billion.

Higher electric and gas prices have direct impacts on the income of Californians, and indirect feedback effects on the state economy. The direct cost, relative to the 1999 prices, is about $50 billion. The indirect effect does not have a substantial impact in the first year, but kicks in over several years. Estimates of the cost of unserved energy are uncertain due to the uncertainty in the shape of the load duration curve and uncertainty in the costs of unserved energy per kWh. Based on the capacity shortage predictions of the California Independent System Operator (CAISO), the number of outage hours will range from 10 to 60 this summer. These outages will impose a cost that ranges from $100 million to $2.5 billion. Based on capacity shortage estimates of the North American Electric Reliability Council (NRC), the number of outage hours range from 100 to 500, considerably higher than those associated with the CAISO capacity shortage estimates. The NERC capacity shortage estimates imply a cost that ranges form $2.5 billion to $54 billion.

Solutions

New market-based pricing approaches and load management programs, in concert with new technology and technical operating practices for generation, transmission & distribution, can enable retail customers to benefit from the restructuring of the electricity market.

In the near term (2001 & 2002), not enough generating, transmission and distribution capacity can be added in time to cope with the electric demands of the burgeoning digital economy. <u>That leaves only one alternative – to use the customer as an asset.</u> The customer must move from a passive role on the "other side of the meter" to an active, real-time role in balancing supply and demand. This means engaging the customer in market-based demand response programs.

Market-Based Demand Response Programs

When faced with a capacity shortage, the best near-term option is to provide customers with an incentive to reduce demand during times of constrained or costly electricity supplies. This reaction to the time-value of electricity can be accomplished through a variety of programs that make customer demand responsive to price changes. Such programs, called Demand Response Programs in this white paper, have the potential for reducing demand rapidly, at low cost, and without adverse environmental impacts. Customers that are willing to pay for the high cost of power may continue to use it at their "normal" levels, while those that are willing to lower demand or shift it to lower-cost periods benefit from lower bills. A 2.5% reduction in electricity demand statewide could reduce wholesale spot prices in California by as much as 24% and help preserve electric power reliability.

Demand Response Programs that explicitly incorporate time-dependent economic signals to customers include:

- Real-time pricing (RTP), in which the customer is usually given some advance warning (generally day-ahead) of the hourly prices for a future time (typically a 24 hour period)
- Coincident Peak Pricing, in which the hourly prices for the projected high cost hours for a year are averaged, and the average price is applied to those hours (probably 100 to 300 hours). Prices for all other projected low-cost hours are similarly averaged. The customer then pays the low-cost-hour price unless the energy provider notifies the customer that certain hours (say the following day) will be high-cost hours.
- Time-of-use (TOU) rates, which differentiate prices by sets of hours in a day, between weekdays and weekends, and between seasons. These rates are pre-set, compared to the constantly fluctuating prices of RTP.
- Demand bidding Programs, in which the customer bids in "negawatts" of reduced demand in order to receive varying amounts of financial incentives.

These pricing approaches encourage the customer to invest in technologies or operating practices that will modify electric demand to relieve generation and T&D constraints. However, a key barrier is the need for advanced meters. Such meters are often called electronic (interval) meters, and need to be distinguished from conventional, spinning disk meters. Such meters are available now, but their cost needs to be reduced through mass production encouraged by user market incentives and/or regulation.

Demand Response Programs also include market-driven load management technologies, such as automated energy control systems (of which the smart thermostat is one example), two-way communication between the customer and the energy supplier, and distributed generation technologies such as cogeneration systems and microturbines. In addition, progress in semiconductors and computer systems has brought forth a variety of new infrastructure technologies not available in the pioneering days of load management. This new crop of digital technologies enables the provision of customer choice, by taking advantage of communications system backbones, such as cellular, paging, and Internet technologies. And these options can be made two-way and closed-loop for more credible verification of demand-reduction-request receipt by customers.

Using these technologies, customers can trade off a degree of discomfort, inconvenience, and distractions from performing normal business functions against incentives, communications/control technologies, degree of exposure to load management requests, etc.

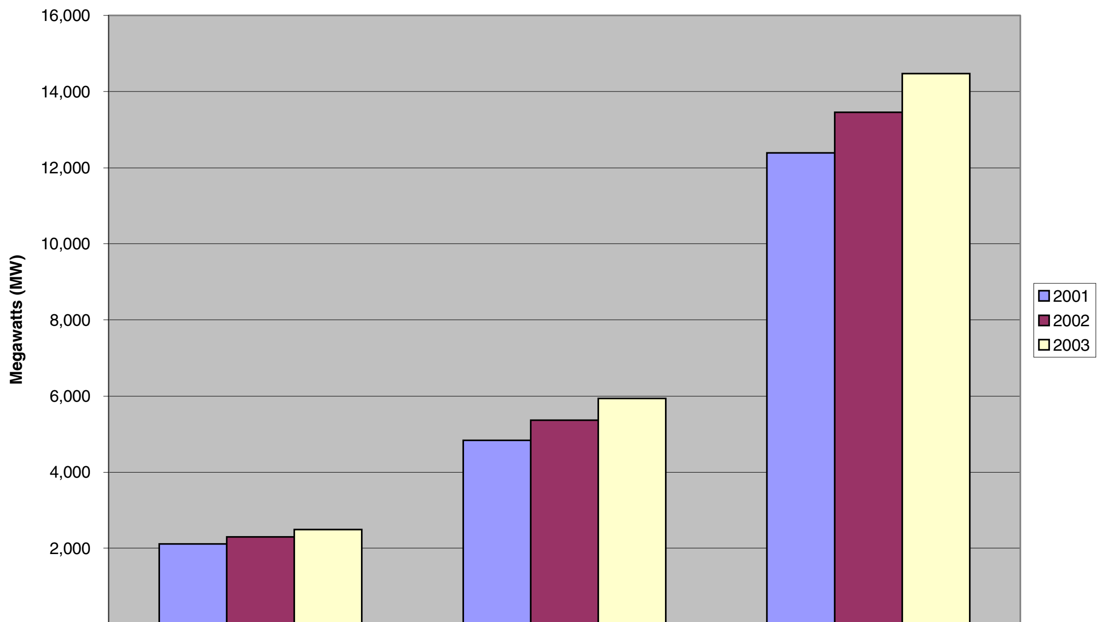
Estimated Impact of Demand Response Programs

Based on an EPRI review of utility Demand Response Programs, these programs have the potential for reducing U.S. peak demand by 45,000 MW. This represents 6.4% of forecast baseline usage. These programs would cost $4.2 billion per year nationally.

The reductions in demand for the Western States and California are 9,000 MW and 4,800 MW respectively – assuming a "medium" response scenario (see below). These represent 7.6% and 8.7% of baseline usage. In addition, demand response programs can offset the need for new capacity, by eliminating 44% and 57% of the forecast load growth during the next years. These programs are likely to cost $840 million dollars per year in the Western States and $450 million per year in California, according to a preliminary EPRI assessment for a "medium" response scenario. (See Appendix A for a discussion of the methodology for estimating the benefit of demand response programs.)

There is considerable uncertainty, however, about how much of this potential savings will be realized, because of three factors: (1) customer participation rate, (2) savings per customer, and (3) changes in the baseline forecast due to changes in weather conditions, energy prices, and the economy. The range of uncertainty in impacts has been estimated by developing scenarios around the likely range of values of these three factors. The results of this analysis for the next three summers in California are shown in Figure 3.5. The relative contributions of each type of Demand Response Programs to the total impact are shown in Figure 3.6.

Impact of Demand Response Programs, California



	LOW	MEDIUM	HIGH
2001	2,122	4,833	12,387
2002	2,299	5,363	13,463
2003	2,486	5,934	14,477

Figure 3.5

Impacts by Program

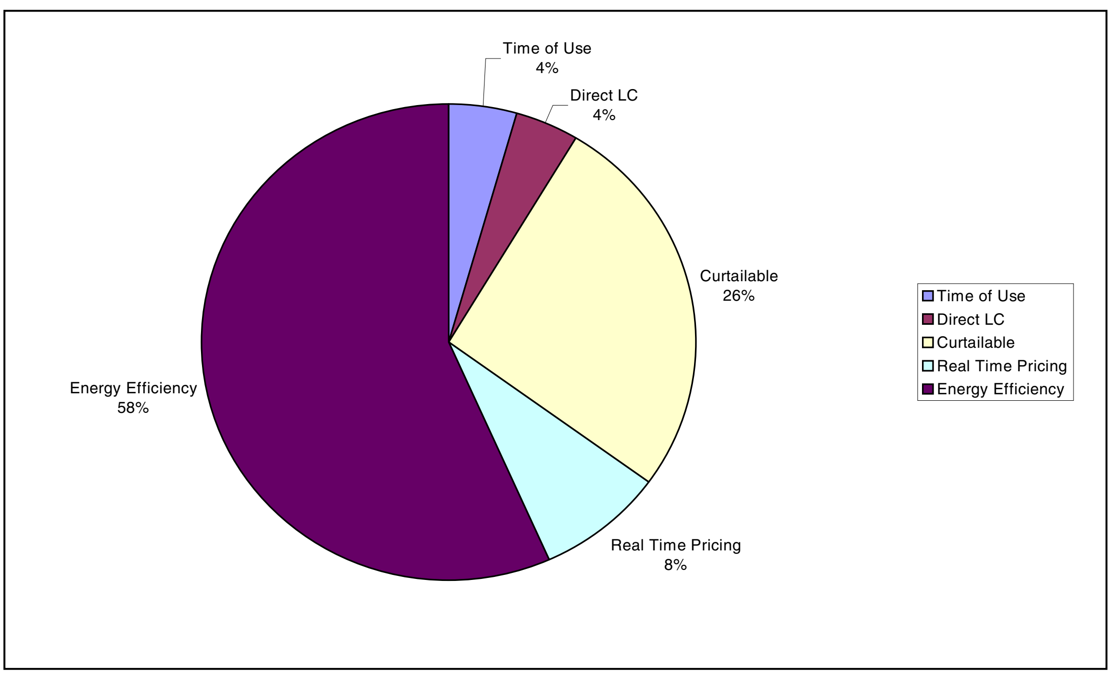


Figure 3.6

Long-term solutions, for the West and the nation as well as California, will require significant additional investments in a balanced portfolio of energy efficiency improvements, transmission grid enhancements, and generating resources.

Managing Risks Using Portfolio Management Techniques

Although the current crisis was due to a fundamental imbalance in market demand and supply, exacerbated by escalating fuel prices, a well-designed market with sound risk management options should be able to function in spite of these problems, and to stimulate solutions. With limited availability of financial instruments for risk management, such as forward markets and transmission rights, a problem was converted into a crisis in California.

As discussed earlier, the market for electricity is characterized by significant price volatility. There is no obvious way to eliminate this price volatility, since much of it arises from difficulties in storing electricity, and from the present lack of liquidity in forward markets for electricity. This problem has been observed not only in the United States, but also in the English, Australian, New Zealand and Alberta power markets. The best way to deal with price volatility is for both buyers and suppliers to have a diverse portfolio of short-term, medium-term and long-term contracts. If power suppliers sell all of their output through fixed-price long-term contracts, they ensure a level of cash flow, but also risk selling their product at a lower price than might prevail in the spot markets of the future. On the other hand, if they don't commit a portion of their supply to long-term contracts, their cash flow for the future becomes very uncertain. Thus, based on their assessment of future price volatility, and their own risk tolerance level, they need to decide what portion of their resource portfolio to sell long-term and medium term, and what portion to sell on the spot market.

Buyers face similar challenges. Entering into a long-term contract insures them against future price volatility, but is achieved by paying an insurance premium in the form of a higher price level. The situation is analogous to buying a home mortgage at a fixed rate versus an adjustable mortgage. Long-term purchases are not devoid of risk, however, because customers may be prevented from benefiting from any reductions in the future price of power.

Thus, both buyers and sellers need to hold a portfolio of contracts. The optimal portfolio needs constant updating and dynamic balancing, as new market information becomes available. In addition, changes in management may bring about changes in a firm's risk tolerance levels, and portfolio balancing may be necessary[5].

Coordinating Wholesale and Retail Markets

When electricity markets are restructured, it is important to restructure both the wholesale and retail markets in a coordinated manner. In the Midwest, during 1998 and 1999, price

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[5] Ralph Cavanagh, "Revisiting the 'Genius of the Marketplace': Cures for the Western Electricity and Natural Gas Crisis", Electricity Journal, forthcoming.

spikes took place on the wholesale market that resulted in the price of electricity exceeding $10,000 for short periods of time. These spikes could have been mitigated by as much as one-half to two-thirds if the retail markets had not been disconnected from wholesale markets. Retail markets were disconnected because their prices were capped, and not based on the fluctuating price of power on the wholesale market.[6]

The same phenomenon took place in California in the summer of 2000 and continues to this day. Wholesale prices determined in an hourly spot market, the California Power Exchange (PX), displayed significant volatility, beginning with May 2000. However, retail prices were capped at their 1998 levels.

To avoid these types of situations from occurring, retail prices should be based on wholesale prices, rather than being frozen. This does not mean that all customers would have to pay hourly prices for electricity. Most customers are risk averse, and would prefer to pay a fixed price. However, this fixed retail price would not be based on a historical value that reflects the cost of service. Instead, it would need to be based on a number of factors such as the shape and volatility of the customer's load, wholesale price volatility, and the correlation between customer loads and wholesale prices. In other words, customers would pay an "insurance premium" to keep their rates fixed.

A coordinated planning process is needed to design power markets and their interface with the underlying infrastructure. The planning process must ensure appropriate balance in reliability and market efficiency as market evolves. In addition, this process should recognize the interdependency of different markets — including the natural gas and electric power markets. The federal and state governments should take the lead responsibility to develop such a process. Ultimately, an independent institution/agency is needed to perform periodic assessments of the performance of the infrastructure, markets and their interface. An important consideration is how to balance the objectives of a strong planning function (to reduce congestion and volatility) against the risks of direct RTO involvement in energy markets.

The importance of computer simulation to aid in the design and operation of the new markets must not be overlooked. Simulation is an ideal tool for power market design, because it is flexible and costs much less than the real world experimentation as the California crisis demonstrated. It is also particularly useful for making comparisons, robustness studies, and the like. It can be used to study new market design or changes in market rules. Restructuring of the power industry presents major new challenges. Newly created institutions, including independent system operations, regional transmission organizations, and power exchanges need not stand only on their own as efficient entities but their designs and operations must minimize the effects of imperfections at the seams. Market simulation can be used first as a tool for managing a process of continuous improvement in market design and eventually as a standard tool in efficient system planning and operations.

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[6] Douglas W. Caves, Kelly Eaking and Ahmad Faruqui, "Mitigating Price Volatility by Connecting Retail and Wholesale Markets", Electricity Journal, April 2000.

Workshop Conclusions

Workshop participants emphasized the need to take a long-term view in proposing solutions to the current crisis. They concluded that the crisis provides an important opportunity to fix underlying problems in today's electricity markets and introduce new technologies that will help make these markets function more smoothly regardless of short-term anomalies and further evolution in the regulatory climate. Specifically, they proposed four broad actions that take a long-term view of market structure, including the need to preserve some of the best features of the old, regulated system and provide new ways for customers to take advantage of market opportunities. These actions are summarized below, along with the corresponding EPRI technical recommendations.

Workshop Actions

Recommendation 3A: Repair Dysfunctional Wholesale Markets

Description: Analyze why market breakdown has occurred, and evaluate opportunities for restructuring market designs and institutions to assure that market information is transparent and available to all market participants in the time frames required.
Benefits: Efficient and transparent wholesale markets are crucial to successful restructuring, in that timely price signals are necessary to connect generation and retail markets and thus provide the benefits expected from competitive markets. An additional benefit is reduction of market power.
Technology Milestones:
2001-2002: Define stakeholder groups and align them on needed market improvements.
2002-2003: Create a unified wholesale and retail market; exploit interdependencies of gas and electricity markets.
Implementation: Market monitoring and performance criteria are significant issues whose resolution is not clear at present. These could become an RTO function, subject ultimately to FERC oversight. Such concerns need to become a significant focus of efforts to create more effective markets.
Barriers: Significant political and regulatory barriers exist at all levels. Also, the need to move wholesale markets to a regional level and engender regional cooperation is a prerequisite for this effort to succeed.
Overcoming Barriers: Developing regional solutions will require cooperation from Federal and state and local government as well as energy companies of all types (investor-owned utilities (IOUs), munis, coops, etc.)

Recommendation 3B: Enable Retail Markets to Benefit from Market Restructuring

Description: Develop the market and regulatory structures, and technology solutions that provide the opportunity to introduce real time and/or time of use pricing, demand trading programs, market-driven load management, distributed energy resources, and new energy -efficient technologies.
Benefits: Improved demand-supply balance, lower energy costs, greater product variety, enhanced customer satisfaction, and greater market participation by new entrants.
Technology Milestones:
2001-2002: Develop supply/demand forecasting techniques; implement real-time pricing and other demand responsive programs.
2002-2003: Develop advanced smart meters; systematically expand use of real-time pricing.
Implementation: Improved portfolio management, including default service is required. Prices are based on cost-of-service methodologies, subject to state regulations. Better market coordination also requires creation of open communications standards and protocols for meters, software and other key interface elements.
Barriers: Lack of information, lack of incentives, lack of enabling technologies, lack of functional wholesale market, lack of customer choice. In addition, manage customer exposure to wholesale price volatility.
Overcoming Barriers: Programs should be implemented at the technical, regulatory, and market levels to facilitate agreement and coordination of efforts to achieve commonality of platforms and capabilities. Efforts to revitalize wholesale markets will also help enable better retail markets.

Recommendation 3C: Support Public Benefit Programs to Overcome Market Barriers to Efficient Use of Energy

Description: There is a need to continue historical efforts in support of programs that promote efficient and cleaner use of energy in areas where market response is sub-optimal or incentives are insufficient to promote action at a high rate of adoption.
Benefits: Lower life-cycle energy costs, cleaner environment, diverse societal benefits.
Technology Milestones: 2001-2002: Expand use of energy efficient technologies for industrial, commercial, and residential applications.
Implementation: Specify codes and standards for minimum efficiency standards are needed for buildings, appliances, and other mass-produced equipment (such as industrial motors). Ongoing programs of incentives to achieve stated objectives should be continued and enhanced, driven by regulatory mandates for distribution companies and their ability to capture sufficient funds.
Barriers: Distribution revenues are currently tied to system throughput, which acts as a disincentive. New funding mechanisms are needed to support programs, together with efforts to determine optimal funding levels. Distributed generation varies widely in environmental performance.
Overcoming Barriers: Institute non-bypassable surcharge on distribution of electricity, and educate the public about the benefits. Empower distribution utilities to serve as focal point of these efforts, and institute pricing reforms that break the linkage between throughput and recovery of distribution revenues (as in Oregon).

Recommendation 3D: Provide Standardized Regional Market Information And Forecasts

Description: Establish a standard set of information that can be used by all parties in the energy equation to better understand issues and potential solutions.
Benefits: Enables everyone to benchmark their planning to a central set of assumptions and data which are available for pricing and growth assessments.
Technology Milestones: 2001-2002: Employ standardized database and communications protocol (e.g., UCA) to establish a central data set for pricing and growth assessments.
Implementation: It is logical for the Regional Transmission Organizations (RTOs) to assume responsibility for this function, with assistance from research organizations such as EPRI and agencies such as the Northwest Power Planning Council or the California Energy Commission.
Barriers: Establishing baselines for information needs; develop forecast methodologies that are acceptable to the involved parties – from generation through retail.
Overcoming Barriers: Identify what information needs to be collected, how often, and by whom. This information was collected previously by state agencies and now certain market participants do not want transparency of market information. Care must be taken to protect corporate confidentiality where needed.

Section 4 – Transmission and Grid Operations

Summary

Because infrastructure maintenance and upgrading have not kept pace with demand, critical portions of the Western Region transmission network are becoming overloaded. Finding solutions to this problem will require both additions to the physical infrastructure and changes in the way Western transmission systems are operated. According to preliminary EPRI estimates, the estimated cost of bringing the regional transmission system back to a stable condition is $10-30 billion, to be spent over the next 10 years on new transmission lines and upgrades of existing facilities. An additional annual expenditure of $1-3 billion will then be needed to preserve this condition. It should be noted that advanced solid state power flow control technologies (e.g., FACTS) and dynamic thermal circuit rating technologies (e.g., real-time conductor sag and real-time transformer loading tools) can reduce the above expenditures by 10 to 30%. These cost estimates are based on investments in the high voltage transmission system (230kV and above) sufficient to achieve the minimal national reliability contingency standard set by NERC. Financial incentives acceptable by the owners of this equipment are urgently needed to perform this NERC standard-based construction work. Key recommendations provided by Workshop participants include:

- Enhance system planning process and construction
- Provide open access to information
- Expand training programs
- Improve maintenance
- Establish mandatory reliability standards.

Introduction

The Western States transmission system was designed and built to operate under significantly different rules and conditions than exist today. Originally, this system was used by each transmission owner primarily to serve their own load, utilizing their own generation. In addition, pre-defined imports and exports of power from outside of their service territory were carried over the network to help ensure reliability and to take advantage of economic opportunities. Today, this system is being used in ways it was not designed for. This includes being relied on to move much more power within and across the Western Region, in support of the wholesale electricity market.

The transmission infrastructure, however, has not kept up with the demands placed on it. Since the wholesale power market was deregulated by the National Energy Policy Act of 1992, very little new transmission capacity has been added and many existing system components are operating well beyond their 30-40 year design life. And, as shown in

Table 4.1 and Figure 4.1, very little new expansion has been projected for the next decade throughout the West. In California, for example, only 145 miles of new lines are planned, which is only about one-half of one percent of the installed base of 27,356 miles.

Table 4-1 -- Existing and Planned Transmission

(Circuit Miles)

Voltage	California*		Western Region**	
	Existing 1/1/2000	Additions 2000-2009	Existing 1/1/2000	Planned 2000-2009
115-161 kV	9,337	54	47,450	676
230 kV	12,356	91	40,290	1,093
287-360 kV	351	0	10,149	88
500 kV	4,243	0	15,997	747
260-289 kV DC	0	0	212	0
+/-500 kV DC	1,069	0	1,333	0
Total	27,356	145	115,431	2,604
% Added	0.5%		2.3%	

* Including lines connecting to Mexico
** Western Systems Coordinating Council (WSCC)

System maintenance has also suffered. Detailed assessments of transmission and distribution maintenance practices performed by EPRI for major utilities across the U.S. indicate that – in many instances – routine maintenance and upkeep of transmission equipment has been significantly reduced over the past decade. While EPRI has not performed this kind of assessment for the Western Region's utilities, it is probable that similar reductions exist here, since these utilities have generally faced the same pressures and followed similar management practices.

As a result of the factors just discussed, key transmission lines are becoming overloaded. The situation is particularly acute in the WSCC, as shown in Figure 4.1, and in California, as shown in Figure 4.2. Detailed information on existing transmission and planned additions is shown in Table 4-1. For the purpose of understanding and managing flow into or out of the state, and between key regions within the State, the California Independent System Operator (CAISO) groups these lines into major transmission "Paths." Power flow into the northern portion of the state, for example, travels over Path 66 (lines connecting between California and Oregon) and Paths 26 and 15 (lines connecting Northern California to Southern California). During the past year, Path 15 has been loaded to its operating limit numerous times and occasionally has been unable to carry sufficient power into the San Francisco Bay Area, causing blackouts. According to the CAISO, reduced imports from the Pacific Northwest this summer, (because of constrained hydro capacity following a severe drought), will further increase the loading on Paths 15 and 26. In addition, flow of power into Southern California from neighboring states is also expected to be constrained. This means that critical equipment – such as large transformers – on overloaded lines will be running at maximum capacity. The failure of a single such critical component could result in unplanned outages that might cascade throughout the Western Region, similar to the multi-state outages of July and August of 1996.

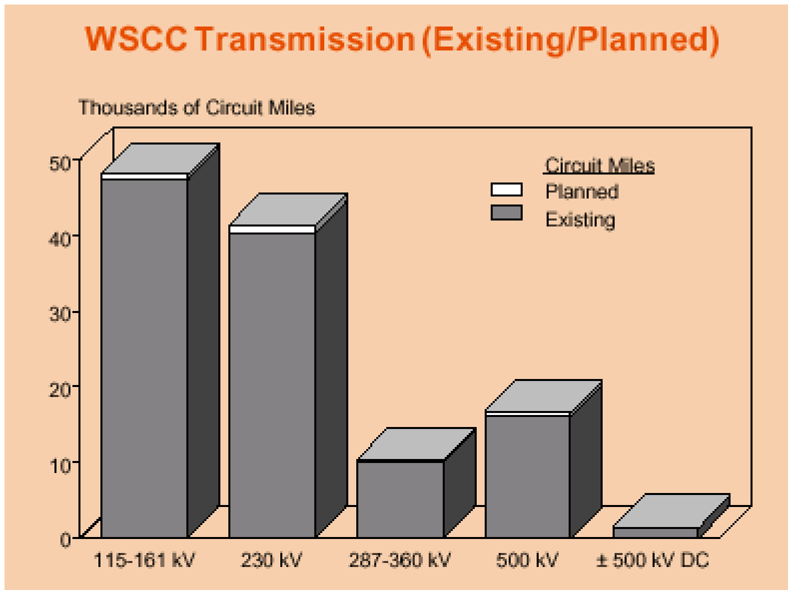

Figure 4.1

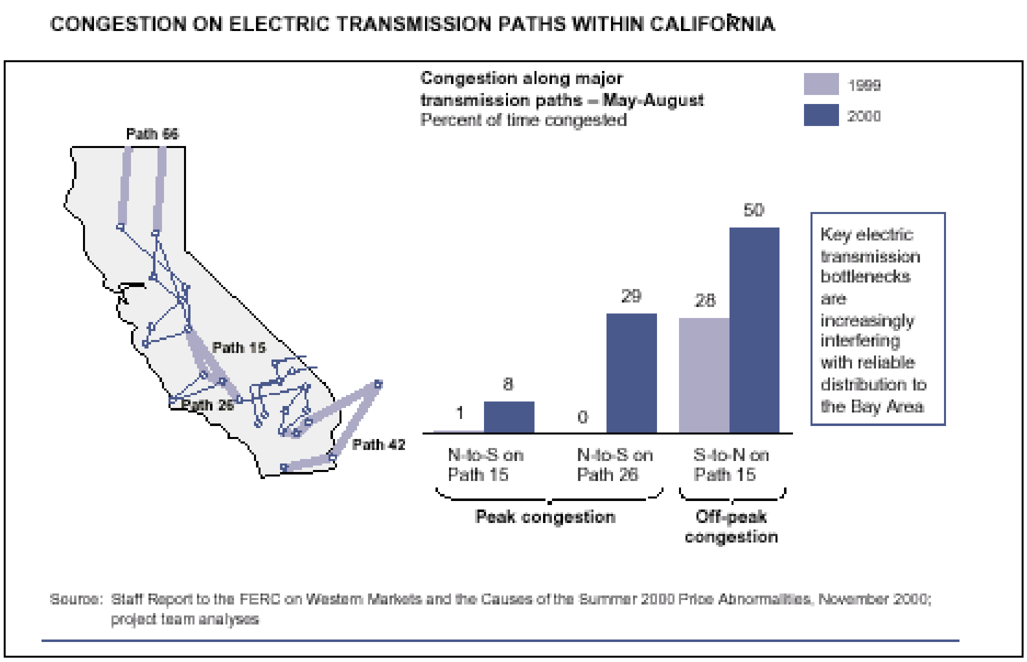

Figure 4.2

Finding solutions to the problems just outlined will require both additions to the physical transmission infrastructure and changes in the way Western transmission systems are operated, maintained, and planned. Remedial actions that can be taken in all these areas are discussed in the following subsections, including specific recommendations.

Prioritizing Maintenance Activities

In the past, individual utilities have performed transmission system maintenance in different ways. Now, a consistent approach for setting maintenance priorities is needed throughout the West, and which considers the region as a whole. In recent years, techniques known collectively as Reliability Centered Maintenance (RCM) have been adopted by many utilities as a means of prioritizing maintenance tasks and allocating resources based on the *criticality* of system components. While individual utilities in the Western region have used RCM techniques for their individual systems, no composite RCM analysis has been conducted for the region as a whole.

In the short term, such an analysis could be conducted quickly and would focus only on the most vital paths within the Western Region's transmission system. Given that the summer load period may already be upon us, this analysis would not -- by itself -- immediately lead to additional maintenance activities. However, it would produce a list of vital components that should be watched and attended to carefully through the summer months, significantly reducing the time to repair this equipment if it does fail and helping restore the grid after an interruption.

For the mid-term, a more detailed RCM analysis should be rigorously performed for the entire Region's grid. This can be used to schedule the most important maintenance tasks during expected light load periods (that is, next fall/spring). This plan can also be used to target components for condition assessment (see next subsection). In the long term, the Region-wide RCM analysis should be updated on a regular basis. The frequency of this update will be determined by the rate with which changes or additions are made to the system and the ever-increasing age of the equipment located in critical paths of the transmission network.

Equipment Inspection and Assessment

The RCM prioritization just discussed identifies system components whose failure would impact the most customers; to find out which are most *likely* to fail, and determine which equipment needs immediate inspection and condition assessment. Non-invasive, rapid inspection and assessment of critical components is possible using a variety of technologies -- many of which have recently been developed. New infrared laser technology, for example, can detect even minute leaks of SF_6 gas from circuit breakers. A Digital Corona Camera can identify damaged or defective insulators in substations or on transmission towers. Vibration and acoustic analysis can determine the health of a transformer's internal structure while the unit is still in operation. And recent advances in digital imaging have made rapid aerial inspection of transmission lines possible, using fixed-wing aircraft and the satellite-based global positioning system (GPS).

Component inspections and RCM assessments are performed for the purpose of classifying equipment into three broad categories:

- Failure is imminent and the equipment must be taken off line for immediate repair (in spite of the fact that the system may be under heavy load and "No Touch" rules are instituted). Equipment in this category may fail suddenly, and this failure may lead to uncontrollable cascading blackouts of the integrated transmission-generation system.
- Equipment is not healthy, but can be run until the next maintenance window of opportunity (i.e., next light-load period)
- Equipment is healthy and no maintenance is required.

Note that there are two steps to this assessment process: The first involves gathering raw operational data on the equipment. The second step involves expert interpretation and analysis of this data to determine the health and/or life expectancy of the equipment.

For the short-term, the initial RCM prioritization described above should be used to identify those substations and lines at the top of the criticality list, and it is in these substations and lines where inspections and assessments should be immediately performed. The purpose of these quick assessments is to identify equipment that is in trouble or near being in trouble, therefore enabling a short-term action plan to be established – including suspension of “no touch” rules, when appropriate. In the medium and long term, RCM techniques should be used to determine which substations, lines, and other components within the system merit the expense of detailed condition assessments, because of their importance. The complexity of the assessment required at each selected site should also be determined. A Region-wide program for inspections/repair, coupled with establishing a uniform and multi-user “open” method of cataloging and storing inspection/repair data should also be undertaken.

<u>Implementing a “whole system” RCM and establishing a set of maintenance “best practices” for the Western Region could lead to an estimated reduction in forced outages of up to 20%.</u>

Determining and Increasing Equipment Thermal Limits

Most equipment in a transmission system (lines, transformers, cables, and circuit breakers) is limited in its ability to carry power by thermal considerations. In other words, the equipment experiences heat related problems, and ultimately fails, if it is asked to carry more than a certain amount of power. Most thermal limits are dependent on load, weather, and equipment condition/age. Prior loading history of the equipment is also a factor in estimating when a failure may occur.

Many of the Western Region's transmission paths are constrained by, or have components that strongly depend on, equipment thermal limits. Historically, thermal equipment limits were fixed based on a set of annual/seasonal assumptions about weather, load history and equipment condition. Because actual real-time conditions vary considerably, worst-case conditions have been used in these calculations – yielding a very conservative limit for the “best” equipment maximum loading level.

By incorporating real-time weather, real-time load and equipment condition information, it is possible to produce an accurate real-time picture of equipment thermal limits. Because this picture is produced from current data, it accurately reflects the present ability of the equipment to perform without failure. The resulting thermal limits are usually (90% of the time) much higher than the fixed limits described above. However, dynamically determined limits vary over time as conditions change, and the real-time limits could occasionally be more conservative than the previously used fixed limits. <u>Applying dynamic thermal modeling to selected Western Region transmission paths could produce an expected increase in rated transfer capacity of 10-30% in the near term</u>.

System Upgrades

Traditionally, the transmission system has been upgraded through the construction of new lines and substations. It is clear – given the long-term growth in the Western Region's energy demand, combined with minimal recent investment in the transmission infrastructure – significant system upgrades are necessary. Even though new lines are needed, new technologies make it possible to substantially upgrade *existing* lines too. Additionally, when new lines (and rights of way) are needed, new technologies allow these to be built with less impact on the countryside than with traditional methods. New technologies include higher strength, low-sag conductors; new materials and methods for tower and foundation design; and new designs for "compact" lines (lines which are designed to carry more power over the same transmission right-of-way).

Although no significant system upgrading can be accomplished before this summer's peak load period, mid-term and long-term, substantial investment and upgrades should be made throughout the Western Region’s transmission system. These upgrades should include the use of common communications standards – collectively known as the Utility Communications Architecture (UCA) – which will facilitate widespread implementation of Web-based diagnostic monitoring systems and real-time network control.

The Wide Area Measurement System (WAMS) is an example of this class of monitoring and control system. WAMS is designed to span the entire grid and control it as an integrated system. In contrast, most of today’s automatic control systems only see and act on local data. WAMS or a similar system should be implemented across the entire Western grid.

Eventually, a nationwide “superhighway” for electricity transmission will be needed to enable inter-regional transfer of bulk power and increase the reliability and stability of the Western region. The Western Region is virtually isolated from the rest of the country, precluding opportunities to import otherwise available and less expensive power from the Mid-West. An early start is needed to correct the deficiencies of the present system and initiate the planning process for a digital superhighway.

The grid of the future will also have self-healing capabilities. That is, it will perform faster than real time simulations with "look ahead" and "what if" contingency analysis to predict the future behavior of the grid and take corrective action before power disturbances occur. Enabling technologies for the self-healing grid include advanced sensors, high-speed data communications, and massively parallel computing.

Large, complex programs such as a national transmission superhighway and a self-healing grid will require a sustained public/private technology development effort. EPRI has initiated the CEIDS program (Consortium for the Electricity Infrastructure of a Digital Society) to provide focus for collaborative research on these topics. Ultimately, programs such as CEIDS will redefine the roles and responsibilities of electricity stakeholders in designing, building, and operating the 21st century electricity infrastructure.

<u>An aggressive transmission upgrade program incorporating advanced technology and Web-based diagnostic monitoring systems could ultimately increase the rated transfer capacity of the Western Region by an estimated 20-50%</u>.

Improving System Stability

In addition to thermal limits, some parts of the Western Region's transmission network are limited in the amount of power they can carry by significant concerns about the electrical stability of the Region's integrated transmission-generation network. Finding ways to ease those stability limits enables the system to operate closer to its thermal limits. New solid-state power electronic technologies are available which can, in many instances, effectively improve system stability and grid control with substantially less investment and impact on the environment. Collectively, these power electronic technologies are known as FACTS: *Flexible AC Transmission Systems*. FACTS technologies enable near-instantaneous redirection of power flow and rapid voltage control of the network when instabilities just start to occur.

These devices can act as "electronic shock absorbers" to help stabilize the Western Region's transmission system, lowering the likelihood of instability-based outages and raising stability limits on key paths in the transmission system. FACTS devices can also be used in metropolitan areas – where old generation may have been decommissioned – to provide the reactive (voltage) support lost when these facilities were decommissioned.

Typically, FACTS can be installed much more quickly than new transmission lines can be built. FACTS can be used to direct power through underutilized portions of the system (and away from overloaded sections). For these two reasons, FACTS technologies can be used as a first step in the process of increasing transmission system capacity.

To realize long-term stability improvements, the Western Region should incorporate FACTS technology as a substantial part of its Region-wide upgraded transmission system. Benefits would include a 20-40% increase in the rated transfer capacity of lines now limited by stability considerations and a corresponding increase of 20-40% in grid stability. In addition, the $10B – $30B capital cost of restoring the stability of the Western grid could be reduced by 10 – 40% through the addition of FACTS systems

"Seams" Issues

With deregulation, the operation and planning for the power grid is moving to an increasing regional scale. In the U.S., some 140 control areas have been reduced to approximately 20 security coordinators, and these, in turn, may be subsumed into about a half-dozen Regional Transmission Operators (RTOs). As the authority for grid reliability has become fragmented, however, the need for large-scale control to coordinate long-distance bulk power transfers has increased.

One of the most visible problems with grid control today involves the "seams" between the various control entities. Each control entity is like its own sovereign nation as far as market and data practices go, and coordinating power transfers that extend beyond the borders of an entity entails complex technical trade-off analyses consistent with how the grid actually responds to inter-regional power flows. Seam problems arise because different control entities have different rules for functions as basic as scheduling and settlement of power transactions. Converting these rules to a consistent basis adds significant hurdles to out-of-area transactions. Control entities that oversee joint business interaction should migrate to a common set of rules.

Applying these rules, however, will require an unprecedented amount of data exchange. The problems arising from data integration are well known for modern computer systems, and generally the task of integrating old data with new software or hardware is much more expensive than the new software or hardware itself. For control areas, the primary problem is with Energy Management Systems (EMS), which collect data about all aspects of grid operations. Many different EMSs exist, from many different manufacturers. To overcome this problem of data integration, new tools have been developed; namely CIM (Common Information Model) and API (Application Program Interface). These tools use a consistent framework for data that can be shared by any EMS, thereby enabling data-exchange across seams between control entities with otherwise incompatible EMS units. The North American Electric Reliability Council (NERC) has advised all security coordinators to be CIM/API-compliant. Many control entities already use CIM/API, and the programs could be implemented within 18 months at the remaining sites within the Western Region and across the nation.

Using such measures to create a "seamless" environment for real-time exchange of grid information among regions could increase power flow among them by 20-40% during emergencies.

Grid Monitoring and Security

Once compatible, consistent data are available on regional scales, the data can be put to use to improve operations of the regional power grid. Thus, when Wide-Area Security Monitoring becomes possible, grid operators will have the ability to control and observe operations during normal and emergency conditions based on the complex electric interactions that occur regionally and inter-regionally for the entire Western Interconnection. It should be noted that a variety of wide-area monitoring tools are available that can exploit the benefits of seamless data exchange for wide-area security monitoring; however, these tools have not been implemented consistently across the Western Region.

The next step is to provide Wide-Area Security Assessment, which depends on "what if" analysis provided by a variety of software tools. Within 18 months, security assessment tools already proved at the control area-scale can be implemented regionally and nationally for voltage analysis, dynamic oscillations, and system topology. These tools show operators where the traditional limits of the power grid are. Within 36 months, additional tools should be implemented to enable operators to safely go beyond the traditional limits of the grid.

Operator Training

The implementation of wide-area power system monitoring and control capabilities present operators with new, never-before-seen conditions and emergency management tasks. Already, deregulation of bulk power sales has resulted in wholly new types of power transfers and grid operating states. Operators everyday now may face situations that no one ever saw in the previous 50 years, and the addition of regional-scale information increases the complexity and opportunity to understand and cost efficiently operate the grid. Moreover, grid emergencies leave little time to reflect on what might be going on; for example, in some recent cases, operators have had only minutes or seconds to react in order to avert major blackouts. Many operators have never conducted a "black start" – bringing back their transmission system after a blackout – even though incorrectly doing so could severely damage needed equipment. Consequently, all operators should refresh their understanding of emergency procedures in the new environment of an overloaded Western Regional grid. A variety of new tools are available to help build operator skill. These tools should be put to work to facilitate operator training by conducting seminars, and classes on a regional or national scale within the next six months – thus helping reduce the likelihood of cascading blackouts.

Regional Planning

As power transactions increase on a regional scale, existing mechanisms for siting generation and transmission facilities have become inadequate. Transmission siting, in particular, requires a regional viewpoint and long-term focus. Load continues to grow, with little transmission construction to support it. Key issues are not getting resolved in a timely manner.

At present, state commissions make major siting decisions, but it is becoming apparent that state concerns and decision frameworks are too small a scale on which to consider siting of needed transmission systems that cross state boundaries. In the long-term, effective planning will require that state commissions take a regional view, and this is starting to happen only on a limited basis. Eventually, the Regional Transmission Organizations (RTOs) proposed by the Federal Energy Regulatory Commission (FERC) are likely to become the organizations in which such long-range planning functions and decisions will eventually be vested.

Interregional Coordination

The "regionalization" of power grid operations and planning is likely to continue well beyond the emergence of security coordinators and ISOs, until North America is left with approximately half a dozen RTOs. Coordinating activities among these RTOs will be an emerging issue, analogous to (but on a larger scale than) the coordination of control areas and security coordinators discussed above.

In particular, the larger, more tightly integrated systems will require more complex assessment studies of voltage and power flow security in order to ensure reliable service. These studies will need to be power flow-based (rather than power contract based) to provide accurate understanding of actual power flow conditions over the grid. New software – which is a bridge from the existing system of security review of contract schedules set by marketers for security assessment of actual flow conditions – could be made available within 18 months.

In the future, NERC (probably under an enhanced mandate and new acronym, NAERO) must be given the authority to play a leading role in setting and enforcing standards and overseeing grid operations. This organization would also set consistent procedures for reporting outage data at the RTO-scale through its working groups. At present, many control areas and security coordinators define and report on outages differently, which will not be acceptable once all are coordinated on a centralized RTO basis.

<u>Establishment of mandatory reliability standards for system operations, planning, maintenance and market interface could lead to an estimated 20-40% increase in grid reliability.</u>

Investment Recovery

Expansion of the Western States transmission grid has been hindered primarily by diffuse responsibility for upgrading facilities, lack of clear market signals to encourage upgrading, scarcity of regional planning, and insufficient return on investment.

Coordinated generation and transmission planning – which were hallmarks of the integrated utility system – no longer exist. But, the market signals that were supposed to replace central planning have not developed. That leaves RTOs, ISOs, and transmission owners without clear responsibility for deciding what upgrades are needed. Since the synchronous grid in the West combines numerous transmission entities into one closely linked, interdependent network, planning by individual entities should be supplemented by overall regional planning. As the Western grid is currently configured and operated, it does not have sufficiently strong regional planning to ensure the stability of the overall system.

Even recognizing that market signals are unclear, additional barriers still exist because of low rates of return allowed by FERC for system upgrades. Typical returns on investment have been in the 9% range, whereas investment analysis suggests that 15-18% may be needed in today's investment climate to stimulate appropriate market reaction.

In addition, the flawed contract-path approach now widely used for power reservations, scheduling, and the grid security/power market interface should be replaced with flow-based technology that respects the physical realities of power flow.

Workshop Conclusions

Discussion by Workshop participants in the transmission area focused on a few major issues. Maintenance received high priority, and participants generally agreed on the need to implement reliability-centered maintenance (RCM) and to use the information gathered to help establish a set of industry best practices for maintenance. Concern was also expressed that lack of maintenance on key equipment during extended emergency periods conditions could compromise overall system reliability. In addition, it was noted that running equipment at full capacity for extended periods tends to wear it out faster, eventually requiring even more maintenance.

The biggest problem facing transmission system planning and upgrades, it was agreed, is the current lack of adequate financial incentives for investment in the underlying infrastructure and lack of alignment between "who pays and who gains" from such investments. As a result, capacity margins have decreased for a decade. In the future, it will also be important to analyze both system reliability needs and public benefits when potential transmission system additions are analyzed.

Introducing new types of operator training was emphasized as a way of making sure that all operators know how to handle rolling blackouts smoothly and that they could effectively manage a “black start” from a major regional outage. There were also calls for wider exchange of system information among transmission operators, power suppliers, and distribution companies.

Finally, Workshop participants generally agreed that appropriate federal legislation is urgently needed to transform NERC to NAERO and grant it the authority to establish a uniform base of mandatory reliability standards for the whole North American grid. The participants also supported the formation of RTOs to facilitate the application of the mandatory standards on a regional basis, for the ultimate benefit of customers who are increasingly reliant on highly reliable power.

Five specific, actions created by Workshop participants for Transmission and Grid Operations are summarized below, along with the related EPRI technical recommendations

Workshop Actions

Recommendation 4A: Enhance System Planning Process and Construction

Description: A comprehensive risk analysis should be made of transmission systems, including public benefits, to determine what additions are needed, and adequate capital investment incentives should be provided, as required to make the system additions.
Benefits: The public’s need for highly reliable power will be met through badly needed infrastructure investment.
Technology Milestones:
2001-2002: Implement calculations of real-time thermal limits, low-sag conductor and new materials for towers to improve capacity and productivity.
2002-2003: Develop power-flow-based technology for system reservations and scheduling.
2004+: Install FACTS on a broad sale to improve power flow and system reliability.
Implementation: FERC, RTOs, Transmission Providers (TPs), States, and power producers would have to collaborate on power system needs and investment incentives.
Barriers: How to obtain agreement among all parties.
Overcoming Barriers: Facilitate consensus negotiation among the parties, with time constraints.

Recommendation 4B: Provide Open Access to System Information

<u>Description</u>: Remove confidentiality constraints among parties involved in providing power through the transmission system and apply real-time information dissemination techniques. Improve outage notification procedures.
<u>Benefits</u>: Market efficiency will improve and the public good will be better assured.
<u>Technology Milestones</u>: 2001-2002: Expand use of data integration tools (e.g., CIM and API) to facilitate data exchange across regional boundaries.
<u>Implementation</u>: FERC, RTOs the power system operators, and control areas should work together to promulgate standards and provide open access to system information.
<u>Barriers</u>: Lack of trust, competitive pressure.
<u>Overcoming Barriers</u>: Build consensus among market participants; some regulatory directives may also be required.

Recommendation 4C: Expand Training Programs

<u>Description</u>: Train operators about how to handle unexpected system conditions. Introduce real-time system analysis for contingency planning. Conduct realistic, region-wide exercises and simulation related to operating transmission systems under stress. Provide better education for emergency agencies and the public.
<u>Benefits</u>: Promote higher system reliability and ensure the public good.
<u>Technology Milestones</u>: 2001-2002: Expand use of existing simulator technology for emergency and outage recovery training.
<u>Implementation</u>: RTOs, ISOs, control areas, transmission providers, regulators and government agencies should develop and administer training programs based on currently available simulation technology.
<u>Barriers:</u> Cost recovery.
<u>Overcoming Barriers</u>: Consensus negotiation and regulatory directives.

Recommendation 4D: Improve Transmission Maintenance

<u>Description</u>: There is an immediate need to improve sharing of information, to develop standards and protocols (maintenance "best practices"), and to enforce compliance with the standards. Additional training is also needed for maintenance personnel.
<u>Benefits</u>: Higher system reliability and increased throughput.
<u>Technology Milestones</u>: 2001-2002: Implement reliability-centered maintenance technology; use RCM to coordinate maintenance needs with system scheduling.
<u>Implementation</u>: Transmission owners should take the lead in implementing RCM and in communicating results to the system operator.
<u>Barriers</u>: Cost recovery.
<u>Overcoming Barriers</u>: Regulatory directives and performance-based rate-recovery.

Recommendation 4E: Establish Mandatory Reliability Standards

Description: Reliability standards should be set by the industry through NERC (NAERO), which would have the authority to enforce mandatory compliance, under FERC oversight. Flexibility should be allowed to make allowance for regional differences.
Benefits: Higher system reliability.
Technology Milestones: 2001-2002: Empower NERC to establish mandatory reliability standards, including UCA, CIM and API, which can be applied immediately.
Implementation: FERC, NERC (NAERO), transmission owners and operators, and equipment suppliers should work with standards-writing organizations to communicate the availability of existing standards and develop new standards where necessary.
Barriers: Agreement among all parties.
Overcoming Barriers: Consensus negotiation and legislative directives.

Section 5 – Supply and Environment

Summary

This section examines the Western power crisis from the perspective of electricity supply. Practical solutions are put forth that look at the potential capacity additions that could be achieved in the next 6-24 months. Ideally, the short-term solutions to the current power crisis will contribute to the long-term sustainable solution as well. This includes maintaining the evolutionary path toward clean power and improving the flexibility and resiliency of the power supply system to provide adequate support for the new requirements of a digital society.

Six major recommendations addressing technology solutions to supply and environmental issues are described in this section. The recommendations are:

- Upgrade the capacity of the existing fleet of power plants
- Implement advanced maintenance practices linked to ISO scheduling
- Accelerate the interconnection of distributed resources and all classes of new generation with the power grid
- Develop incentives for cleaner emergency generators
- Develop a process for regional planning of capacity additions
- Develop alternate generation technologies to increase resource diversity and reduce over-reliance on natural gas

Although a detailed assessment of the costs of implementing these recommendations has not been done, it is possible to make some preliminary estimates. The recommendations are summarized in Table 5-1. These measures will increase available power plant capacity in California by 3,400MW to 5,100 MW, for a total cost of $460M or less. In addition, alternate generation technologies could offset 10,000 MW of gas generation in the Western States for a cost of approximately $5B over the next 5+ years. Finally, adding large amounts of central station generation could cost as much as $20B through 2007.

Introduction

<u>Until large-scale storage of electricity becomes practical, electricity must be generated to closely follow the swings of demand in real time.</u> Unlike telephones, there is no "busy signal" to ration the resource among neighbors when demand exceeds supply. With electricity, the system operator either meets the demand of everyone or an outage ensues somewhere. At best this leads to a temporary interruption of power for a small set of willing customers; at worst it can entail a large-scale outage that cascades over an entire

region. Lacking an inventory to buffer the mismatch between supply and demand, the degree of coordination that is required between electricity producer, transporter, and consumer, is the most exacting in economic history.

Table 5-1: Potential Power Plant Capacity Increases in California

Plant Upgrade Opportunity	**Increased Capacity, MW**	**Cost, $M**
Fossil steam plant turbine upgrade; other system upgrades	500	200
Gas turbine inlet cooling	200 – 500	20 – 50
Nuclear plant steam turbine upgrade	100	10
Biomass (regulations to assure timber availability)	700	2
Cogen (similar approach to fossil steam units, but lower cost activities assumed)	600 – 800	60 – 80
Improved Maintenance Practices (increased availability and capacity during high-load conditions)	800 – 1,500	120
Accelerate interconnection of DR and backup generation (assure availability of additional capacity in the near term)	500 – 1,000	5
Total	3,400 – 5,100	410 – 460
Alternate Generation (assumed cost of $500/kW is the differential between alternate generation and lower cost NGCC)	10,000 (displaced NGCC capacity, not new generation)	5,000

<u>The substitute for the missing inventory function in electricity markets has traditionally been excess generating capacity</u>. Until the 1990s, U.S. utilities maintained a comfortable capacity margin of 20-30% over peak demand (25% on average), but since 1992, the U.S. margin has declined to less than 15%. The Western States Coordinating Council reports an overall margin of around 17% currently, but much of that capacity has not been available to the California market for a variety of reasons, including low hydro levels in the Northwest. Some reports suggest that hydro imports to California from the Pacific Northwest may be as low as 700MW this summer. After factoring in imports from the Northwest and the Southwest, the California ISO estimates a shortfall in June 2001, of more than 3600 MW, or roughly 7% of the state's peak demand. As new capacity comes

on line this summer, the shortfall could drop to 2-3% by September. With more than 2,000 MW coming on line this year in California, and additional 3,000 MW of baseload capacity in 2002, as well as 1500 MW of peaking capacity, the supply/demand balance may well be restored within three years. <u>However, the capacity margin will remain slim for some time, leaving California vulnerable to the vagaries of imported power from the Western states, and keeping the Western states vulnerable to price spikes in the large California market.</u> Exacerbating this problem is the fact that the Pacific Northwest part of the Northwest Power Pool is at least 3,000 MW short of historic reliability levels. It will, therefore, be very difficult to import power from the Northwest to California at anything like historic values.

Evolution of the Power Supply System

For both economic and environmental reasons, the U.S. power industry has made a major commitment to gas in the last decade. Gas-fired combustion turbines (CTs), in simple and combined cycle modes, now account for 85% of new capacity in the U.S., and the percentage is still growing. Figure 5.1 shows that the surge in construction will reach nearly 90 GW by 2003.

Actual and Planned Combustion Turbine and Combined Cycle Additions

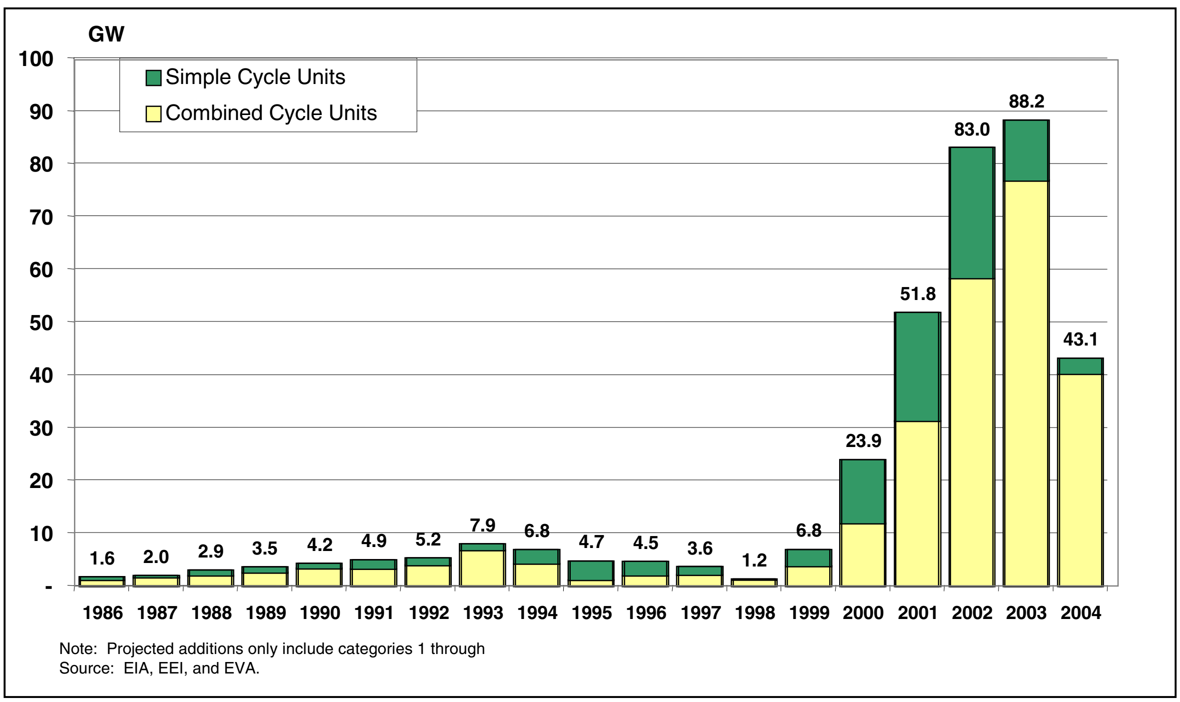

Figure 5.1:

<u>With these large gas capacity additions, the gas and electricity grids are becoming increasingly interdependent, and can now be thought of as an integrated energy delivery system</u>. Gas pipeline capacity is therefore becoming an integral concern of the electricity

supply system, as evidenced by the electricity price increase caused by a rupture of a main gas artery into California during the summer of 2000.

Upgrading the Existing Fleet

New technology solutions have the potential for increasing the generating capacity of existing power plants and recovering lost capacity. Several of the approaches described in this section will result in increases in emissions, and therefore will trigger the need for environmental review and re-permitting, as well as offsetting emissions where required. Under some conditions, upgrades that do not increase emissions may not require repermitting.

<u>Fossil Steam Plants</u>.

Over an 18- to 24-month timeframe, older fossil-fired resources can be upgraded to produce more power, improve generation efficiency, and reduce costs. Opportunities include changes such as replacing the steam turbine hood and blading with more efficient designs, feedwater heater upgrades, or upgrading materials in the furnace or superheater section of the boilers to enhance reliability. In the next two years, upgrades could cost effectively add 5% to the capacity for many units and an estimated total of 500 MW in California.

<u>Combustion Turbine and Combined Cycle Plants</u>.

Combustion turbine and combined cycle plants can achieve significant additional capacity by increasing the temperature differential between the inlet and exhaust streams. Typical combustion turbines lose 1% of rated power output for every two degrees Fahrenheit increase in ambient temperature. On a 100ºF summer day, for example, combustion turbine output is reduced by 10% from that of an 80ºF day. One method of regaining this lost capacity is to cool the air entering the combustion turbine with inlet air fogging or refrigeration systems. Effective inlet air cooling can actually result in power output exceeding the rated capacity. Combined cycle units can also have heat added, through duct burners, to the combustion turbine exhaust, resulting in substantial increases in power output. These technologies are widely used in new plants, but significant opportunities to improve output exist for retrofit applications. With the existing fleet of CTs, the potential for California over the next 18-24 months is estimated between 200-500 MW.

<u>Reconditioning Mothballed Plants.</u>

Several older fossil-fired steam units have been retired or placed on standby service within the past ten years. According to information from the California Energy Commission, <u>mothballed gas-fired units larger than 50 MW represent more than 2,000 megawatts of now idle capacity in California</u>. Some fraction of these are still in good condition, and could be refurbished and placed in service in 6-18 months by upgrading the plant control systems and backfitting environmental controls. The ancillary equipment, such as substations, transmission links, natural gas supply, and cooling water are all present at the plant sites, thus reducing the time and money needed to bring the plants on line. While these units do not provide the same energy conversion efficiency as a modern combined cycle plant, they can be competitive with peaking gas turbines for efficiency. Upgrading mothballed plants will also require meeting existing environmental regulations, especially for air permits. Restarting these plants may also require working with the local community to address environmental justice considerations.

Hydroelectric Power.

There are currently about 95,000 MW of hydroelectric capacity in the U.S., including about 61,000 MW in the Western States (inclusive of California) and just over 9200 MW in California. However, summer drought conditions in the Pacific Northwest will severely limit the hydro power generation this year. Against this backdrop, several opportunities exist to increase hydro capacity or at minimum reduce hydro capacity losses. These are:

- Reliability-Centered Maintenance – Increased cycling of units can lead to accelerated aging of critical plant equipment. Exacerbated by low water conditions, plants are cycling more frequently in order to manage available water and generate only during those few hours of most critical need. Increased starts and stops increase the fatigue rate of components, and may accelerate aging. Reliability-centered maintenance can limit damage accumulation and can provide the basis for integrating plant maintenance needs with ISO scheduling of off line periods.
- Relicensing – Over the next 3-4 years, licenses will expire for approximately 500-1,000 MW of existing hydroelectric facilities in California and 2,500-3,000 MW in the western States. This situation raises two uncertainties – whether the original licensee will have the 'new' license and whether some portion of existing generation capacity will be 'lost' to competing uses or for other reasons. FERC can help reduce these uncertainties by assessing the need and appropriateness of automatic five-year extensions of licenses to firm up capacity during the next few years.

Nuclear Power.

Over the last few years, the U.S. nuclear power industry has developed a systematic approach to improving the rated capacity of existing nuclear plants. Four approaches have been defined:

- Reanalysis of the Nuclear Steam Supply System – New analytical methods and computing techniques reduce conservatism and allow more accurate assessments of the performance of nuclear reactors. This permits safe operation of the plant closer to the operating limits.
- Improving Feedwater Control – Improved instrumentation allows better control of feedwater temperature and flow rate, two of the key operating parameters that

determine reactor power output. Again, better knowledge of plant operating conditions allows safe margin reduction and higher power output.

- Turbine Replacement – New steam turbine designs are available that increase efficiency and therefore power output. Plants already planning to replace turbines can increase capacity by upgrading to the newer designs.
- Steam Generator Replacement – Plants with degraded steam generators (large numbers of plugged tubes) can regain lost capacity by replacing steam generators. Note that this approach recovers lost capacity, rather than adding capacity above the original nameplate rating.

Of these approaches, the first two can be implemented in a relatively short timeframe, if the necessary regulatory approvals can be obtained in a timely manner. The other approaches will generally require more time and expense. A detailed analysis of the opportunities for increasing the output of the nuclear plants in California has not been performed, but a preliminary evaluation suggests that an additional 100MW of capacity may be achievable at California's nuclear plants, through judicious application of the upgrade technologies described above.

Renewables and Cogeneration

Various renewable energy technologies and cogeneration are important and significant generation resources in the U.S., more so in the Western region, and particularly in California. These resources can play a major role in helping to meet power needs during the projected shortfalls over the summers of 2001 and 2002.

Wind and solar facility output usually does not coincide with periods of peak electricity demand. Solar output tends to correlate better than other renewables, at least in the southwest and California markets, where peaks are driven largely by air conditioning loads. However, usage of renewable technologies is tempered by their inability to be dispatched exactly during times when revenues might otherwise be maximized.

There are several opportunities to firm up renewable technologies and insure enhanced availability of renewable and cogeneration:

- Improved scheduling coordination of intermittent wind and solar generation and expansion of storage capability to provide additional power to the grid during peak times. A reasonable goal would be to increase from 20% to 40% the 'on-peak' capacity of existing wind facilities. This would increase peak capacity of California facilities by 360MW through a combination of improved day-ahead wind forecasting and modular storage.
- Rationalization of timber harvest regulations for biomass and accelerated promulgation of new regulations, if even on an interim basis. This will ensure availability of California's existing 700 MW in biomass plants.
- Cogeneration facilities can benefit from many of the same upgrades identified for fossil steam and combustion turbine and combined cycle plants, as the fundamental technologies are similar. Cogeneration installations are typically

younger than other fossil fired units, so the upgrade potential is smaller. Nevertheless, capacity upgrades of 3-4% are possible, for an approximate 600-800MW gain during the next 24 months.

- Combined heat and power (CHP) installations can greatly improve efficiency and reduce primary energy requirements. A longer-term goal is to screen and develop CHP opportunities.

Improving Plant Maintenance

Maintaining the reliability of generating equipment is key to the reliability of the entire power system. However, plant maintenance has been a secondary priority during the recent power emergencies. Moreover, maintenance at most plants has been cut severely in recent years, because plant operators have been under considerable pressure to reduce generating costs. This trend is now exacerbated by ISO mandates of “no touch” periods extending from weeks to months. Maintenance reductions may eventually increase the risk of equipment failure during critical periods, resulting in additional damage to the system and the possibility of cascading outages. Advanced monitoring and diagnostic techniques can assess the condition of key systems while the plant is on line, and determine whether faulty equipment should be brought off line to prevent more serious damage.

Ultimately, better communications are needed between the plant operator and the ISO to use the results of on-line monitoring systems and RCM methods (described in Section 4) to determine whether and when to remove systems from service for repair. Direct communications with the ISO can also help determine whether the imposition of mandatory “no touch” periods will be counterproductive in terms of increasing the risk of on-line failures.

Distributed Resources

Distributed resources (DR) are a group of technologies with the long-term potential to revolutionize the power system of the future. In the near term of the next few years, it is possible to use existing and new DR to back up the grid during power emergencies. However, to understand the potential of DR, it is necessary to get beyond the hype that characterizes many discussions of this technology.

DR is defined in this document as generation of a few kilowatts to ~30 MW in size. Typically, DR greater than 20 MW is a gas turbine installation used in a localized cogeneration mode supplying both power and process heat. Devices of 20MW or more are frequently grid connected and synchronized to both the in-plant electrical system and the local grid. DR less than 20 MW includes small frame gas turbines and reciprocating gas and diesel engines. Emerging microturbine, fuel cell, and distributed renewable technologies do not have sufficient market share or production volume yet to be meaningful contributors to backup capacity or energy in the next 2-to-3 years, but allowing for their strategic integration with the grid is critically needed.

The exact amount of DR power now installed on customers' premises is unknown, but estimates suggest that there are some 4,000-5,000 MW of small DR (under 1-2 MW) in California alone. For the United States as whole, there are approximately 50-100 GW total of DR units under 50 MW. In recent years this amount has been growing by about 5,000 MW per year. The California Energy Commission is currently conducting a survey of emergency backup generators at commercial and industrial sites for the entire State.

Although the total generation is significant, relatively little DR is available to support the power grid directly. Only about 20% of DR capacity is electrically interconnected with the grid for continuous operation. About 50% more can be synchronized to the grid for load pickup when DR generators are brought on line during startup but is not equipped for continuous connection with the grid. The remaining 30% is not connected or synchronized. Instead, it is designed to come on-line only when grid service has been interrupted. There are several opportunities for increasing the value of the DR resource for providing backup power.

Accelerated Interconnection of DR

Synchronizing DR with the power grid is the most direct means of providing additional support to the power grid. However, synchronization equipment is expensive – the cost can be as high as 10-25% of generator cost. Because of the cost and environmental considerations (discussed below) the amount of fully synchronizeable DR in California over the next year will probably be less than 1,000 MW. Nevertheless, distribution utilities may be able to develop protocols for calling on large customers to disconnect from the grid and use their backup generators during periods of high power demand.

Incentives for Cleaner Emergency Generators.

Air quality is a major concern regarding any significant increase in the use of backup diesel generators. NO_x exhaust gas concentrations from diesel generators (most of which operate without emissions controls) can range from about 250 ppm NO_x to over 800 ppm NO_x – 10 to 300 times that of large commercial scale combustion turbines. In addition, diesel generators emit significant levels of particulates and CO. The State of California classifies particulate emissions from diesel engines as a toxic air contaminant.

For these reasons, regulatory agencies are reluctant to allow operation of these generators unless blackouts are in process. Operation of such generators is usually not permitted during Stage 2 or 3 alerts because of the high emissions levels, even though such operation would have the effect of reducing the load served by the grid. However, there is no restriction on operation of diesel backups once an outage has occurred.

The regulations restricting use during stages 2 or 3 could limit use of diesel generators when they could be used to provide a public benefit of helping to prevent outages, while allowing unlimited operation of the generators during outages, resulting in a solely private benefit.

To address the need for additional power during periods of high demand, Governor Davis of California recently issued an Executive Order allowing natural-gas-fired plants to operate beyond their emissions or operational hour limits to minimize the use of backup diesel generators.

But cleaner emergency generation is possible. Filters can used to control particulate matter emitted by diesels, and selective catalytic reduction (SCR) can be used to control NO_x on larger units. Conversion kits to allow diesels to run on natural gas are also available. Depending on the range of engine sizes, these control technologies can be very costly, ranging from $15,000 to $100,000 for typical size diesels.

Other technology candidates for distributed low emission backup generation include microturbines, fuel cells, and renewables. Acceptance of these technologies is contingent on creating incentives for investment. In addition to financial incentives, it may be possible to expand emissions trading, offsets, and credit programs to help reduce emissions from backup generation.

Generation Expansion

Ultimately, it is important that California and other power-short parts of the country build new generating capacity. In the Silicon Valley of California, for example, local load growth rates have approached 10% per year, much higher than imagined even a few years ago. The resulting imbalance between demand and ability to meet that demand is a major contributing factor to the high power prices, tight supply, and power outages experienced in 2000 and 2001.

The realization that California is desperately short of power has spurred a crash program to add new generation capacity. Already, power producers have filed applications to build 14,000 MW of new capacity in California. More than 3,000 MW of capacity will be added in 2001 alone. Forecasts of new capacity additions vary widely, from 393,000 MW by 2020 (US DOE Energy Information Agency) to 305,000 MW planned by 2007 (EPRI analysis). Interestingly, the California additions are forecast to be less on a per capita and per unit GDP basis than for the rest of the country.

Combustion turbines and combined cycles are the overwhelming choice for new generation. Peaking plants being installed are usually simple cycle machines designed to come on line within six to 18 months. Depending on design and size, these units may be field-erected, modular, skid- or barge-mounted, and can be installed in a relatively small area (typically at industrial sites). These machines are usually 50MW or smaller with a total plant cost of approximately $400/kW. Larger combined cycle plants are also being installed. These are generally sized at 500MW or higher, have an average capital cost of ~$600/kW, and must meet stringent environmental control requirements. However, there is a two- to three-year backlog of orders for combustion turbines, so capacity additions for which turbines are not already on order, will probably not be available for at least two years.

Siting and Permitting.

The length and complexity of the power plant permitting process has contributed to the shortage of generation in California. Recognizing that the State is in an energy crisis, Federal, State and local regulatory agencies are acting to expedite the permitting processes. Recent progress includes the siting of over 10,000 MW of generation units larger than 300 MW, and more than 800 MW of peaking capacity. (These figures change frequently as applications are processed. (For details, see the CAISO Power Plant Siting Update at http://www.energy.ca.gov/sitingcases/backgrounder.html.) Regulatory agencies have been allowing additional permitting flexibility to reduce the time for approving plant applications. For example, if a permit applicant cannot secure NO_x catalyst in a timely manner, EPA and local regulatory agencies are issuing Consent Orders to allow facilities to operate with higher NOx emissions (e.g., 25 ppm vs. 2.5-5.0 ppm) through May 31, 2002. Other specific requirements may also be imposed. These could include payment of a penalty, securing additional emission offset credits, and a commitment to install pollution control equipment at some future date. The EPA has issued guidelines for expediting the siting process, as has the State of California in its 21-day peaker siting process.

Thus, fast track permitting, especially during periods of electricity supply shortfalls, is critical to attaining and maintaining sufficient generating capacity. In California the shortage of NO_x offsets can constrain the siting process and also push the cost of available offsets to extremely high levels ($45/lb. in 2000).

An alternate approach is to allow inter pollutant trading among media. For example, NO_x emissions offsets could be obtained via additional reductions in water discharges, CO_2 emissions or enhancements of wetlands. Perhaps the NO_x offsets themselves could be obtained at a later date to expedite permitting, thus achieving not only NO_x reductions, but much broader incremental benefits.

Scale of Investment in New Generation

The task of providing for the generation needs of the western U.S. is daunting. An investment of almost $20B will be needed through 2007 to bring on line over 40,000 MW of capacity, as shown in Figure 5.2. These projections are based on announcements by developers, plants already permitted and those plants under construction as of April, 2001. Almost half this expected capacity will be in California. However, the completion of these plants as currently scheduled is by no means assured given the formidable challenges of financing and siting, particularly in California. Some developers have recently expressed reservations about building new plants in California due financial and regulatory uncertainties.

Siting these plants will require consideration of the location of the plant with respect to load centers, gas pipelines, and transmission lines, in addition to environmental issues. Moreover, public concerns about living and working near a power plant have surfaced in some plant siting proceedings that have stalled construction plans. (An example is the

Metcalf project in San Jose, CA. This plant, recently received approval of the local city council, but only after a one-year delay).

U.S. Actual and Planned Capacity Additions 1998 – 2007

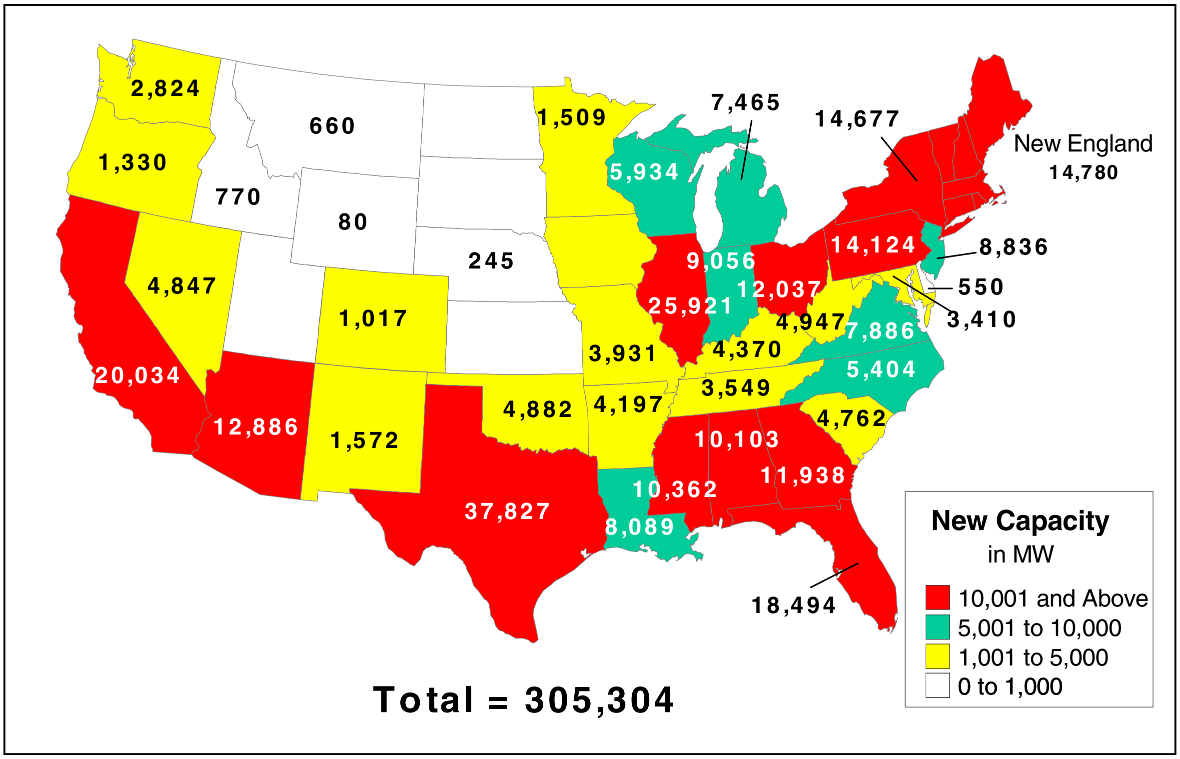

Figure 5.2 Source: EPRI

What is needed now is an approach for regional coordination of power plant environmental and siting approvals that meets the needs of all Western States power system stakeholders.

Need for a Balanced Generation Portfolio

Although the construction of new plants will address the critical near-term need for power generation, it may create longer-term problems. For example, nearly all of the planned capacity additions in California will be combustion turbines or combined cycles, fired by natural gas. In fact, the present rate of increase in gas for power generation throughout the U.S. is unprecedented. EIA projects that this appetite for natural gas will cause power generation to surpass residential use in 2005 and all other industrial use by 2015. The predictable results include higher gas prices, vulnerability to interruptions in gas supply, and erosion of the diversity of the fuel supply.

It's clear that California and the rest of the country need to develop a more balanced portfolio of energy sources and generation options to avoid the high prices and impacts of potential supply interruptions. In California, the portfolio currently consists principally of hydroelectric, nuclear, gas, and out-of-state coal, with minor amounts of biomass, geothermal, and wind. Nearly 20% of California's electricity is imported from other States. While a cursory look at this generation mix suggests that the portfolio is balanced, California is on the verge of an over-reliance on natural gas. If all the planned additions are built, well over half of California's generation will be gas-fired, compared with about 30% now.

Although the use of oil for power generation has declined in recent years, it may be possible to use oil to increase fuel diversity. Some existing plants in the Sacramento Delta, San Francisco Bay Area, Monterey Bay, and South Coast Air Basin were at one time capable of using low-sulfur fuel oil or distillate. Given the likelihood of future high gas prices and volatility, it makes sense to reevaluate the option of using oil in these plants to help limit gas price increases. The increase in emissions associated with oil firing, however, will require re-permitting and emissions offsets.

The generation portfolio should also reflect a general risk-mitigation approach. The portfolio should balance small and large units, base load and peaking, and different types of financial exposure. Beyond their environmental and resource utilization benefits, renewables can also provide a financial portfolio-balancing element. Renewable technologies generally have high fixed cost components but low variable costs, and are thus relatively unaffected by disruptions in fuel supply or high prices. Nuclear generation costs are also dominated by fixed costs. On the other hand, gas generation is dominated by the variable cost of fuel. A portfolio that combines these elements will provide a hedge against fuel price volatility on the one hand, and high capital charges on the other hand.

Finally, maintaining a balanced generation portfolio will require technologies that complement gas generation at competitive cost and environmental performance. This suggests the need for research aimed at clean coal, nuclear, and renewable generation, and storage technologies to complement broad-scale deployment of renewables.

Workshop Conclusions

The discussion of power supply and environmental issues at the Workshop focused on the importance of increasing the availability of backup generators to meet near-term demand growth without sacrificing environmental values. The participants noted that the current deficiency in generation assets might turn into a glut on the market if all the announced capacity additions in the Western States are actually constructed.

The Workshop participants also emphasized the importance of processes for accelerating the interconnection of distributed resources and new generation with the grid

Finally, the participants recommended a systematic region-wide program for increasing the generating capacity of the existing fleet, and the implementation of a process coordinating critical equipment maintenance needs with ISO operations. These actions are summarized below, along with EPRI's related technology milestones.

Workshop Actions

Recommendation 5A: Emergency Backup Generation

Description: Address cost/benefit considerations (economic, environmental, etc.) of using emergency backup generation to switch load off of the grid during periods of high load and imminent blackout.
Benefits: Up to 500 MW of added generating capacity during periods of peak load.
Technology Milestones:
2001-2002: Define interconnection and environmental requirements
2002-2003: Deploy clean backup generator (e.g., clean diesel, gas ICEs, gas turbine, fuel cells) and integrate with the grid.
Implementation: Equipment suppliers and users, distribution utilities, and regulators should define technology and regulatory requirements.
Barriers: Political considerations; environmental concerns – particulate and NOx emissions, noise.
Overcoming Barriers: New technologies for emissions reduction; public/private commitment to resolve issues.

Recommendation 5B: Upgrades to Increase Generating Capacity of Existing Fleet

Description: Workshops and documentation of best in class practices.
Benefits: Up to 4,000 MW of additional generating capacity.
Technology Milestones:
2001-2002: Provide training and guidelines on implementing capacity upgrades.
2002-2003: Increase capacity through steam turbine upgrades, feedwater heater improvements, gas turbine inlet-air cooling.
Implementation: Generation owners and technology developers should sponsor workshops and benchmarking; regulators and legislators should address the need to create incentives for investment in plant upgrades.
Barriers: Plant owner financial uncertainties and investment, regulatory, and environmental risks.
Overcoming Barriers: Quantify benefits and costs for all stakeholders, using risk-based methods, e.g. real options analysis.

Recommendation 5C: Reduce Overdependence on Gas

Description: Demonstrations of new generating technologies for intermediate term and beyond (renewables, advanced coal, fuel cells, nuclear) to provide a balanced portfolio of generation options.
Benefits: Displace need for up to 10,000 MW of natural gas generation over the next five years; avoid price run-ups; contribute to national security.
Technology Milestones: 2001-2004+: Develop and commercialize biomass, wind and solar photovoltaic generation enhancements; coal gasification and integration with solid oxide fuel cells; pebble bed modular nuclear reactor.
Implementation: Department of Energy, equipment suppliers, and power producers should find collaborative research and development initiatives for new generation technologies.
Barriers: Short-term focus of power generation business, declining research and development budgets.
Overcoming Barriers: Collaborative programs involving federal and state agencies, generation companies, equipment suppliers, and other stakeholders to develop a consensus on needed work and reduce investment risk.

Recommendation 5D: Integration of Maintenance Scheduling with ISO Operations

Description: Use information on critical equipment condition to determine need coordinate maintenance requirements with ISO operations scheduling.
Benefits: Fewer forced outages; improved availability of equipment during high electricity demand conditions; better communication between power producers and ISO regarding equipment availability.
Technology Milestones: 2001-2002: Enhance maintenance practices through RCM and other condition-based maintenance systems; integrate maintenance needs with ISO operations.
Implementation: Power producers should take the lead in implementing RCM and working with the system operators to incorporate RCM results into systems operations decisions.
Barriers: Contracts; current practices such as "no-touch" periods during which maintenance cannot be performed.
Overcoming Barriers: Workshops and analysis to determine procedures for assessing equipment condition; incentive structure for improving coordination between Power producers and ISO.

Recommendation 5E: Accelerate Interconnection of DR and New Generation with the Grid

Description: Develop consensus on a series of industry standards and best practices to facilitate making the physical connections to the grid of new generation and existing DR.
Benefits: Quicker installation; easier to local support for new facilities.
Technology Milestones: 2001-2002: Define interconnection requirements, including standards and best practices.
Implementation: Power producers, equipment suppliers, regulators, state and local agencies should collaborate on development of standard practices for grid interconnection.
Barriers: Inherently complex processes; no consensus on who pays for upgrades to meet new standards and recommended practices.
Overcoming Barriers: Continued support for IEEE standards process; workshops and interactions with local grid owners and operators.

Section 6 – Conclusions

This paper contains 19 specific actions to help resolve the current power crisis in the Western region, as well as to establish a transition pathway to a sustainable electricity infrastructure. In addition to regulatory and market reform, all of these recommendations require the application of new enabling technology to meet the policy objectives in an efficient and timely manner. Mindful of the urgency of the current crisis, and the implications for the nation, the participants of the Western States Solution Workshop concluded their discussion by developing a short list of primary issues that cut across the 18 specific actions. These include the near-term and longer-term issues of greatest importance.

Primary Near Term Issues

- Implement demand-side strategies to reduce load in the short term, and to begin the process of establishing greater demand-response to price signals.
- Facilitate faster integration of distributed resources (DR). This includes setting technical standards, defining when and where backup emergency generation can be used to support the grid, and developing better systems architecture for tying DR into the existing grid and establishing two-way flow of power.
- Optimize maintenance practices to reduce forced outages of power plants, transmission lines, and distribution systems, and to schedule equipment maintenance in conjunction with ISO requirements. The use of reliability-centered maintenance (RCM) techniques, and documenting "best industry practices" should allow reduction targets of 20-40% in both generation and delivery-related outages.
- Provide better outage coordination among system operators, generating units, public safety institutions, business and media. Greater exchange of information, and experience among various system operators would be a critical link of coordination. More rigorous training of operators in "black start" conditions would be helpful in restoring service following a major outage.
- Ensure investment recovery of new technology needed to create a functioning competitive marketplace for electricity. This includes technology to ensure demand-response capability on the retail side, and a portfolio of pricing options for customers. Investment recovery should be extended to R&D as well.
- Get more out of existing assets, including generation, transmission, distribution and end-use technology. For example, up to 5,000 MW of capacity could be added in California in the next two years by upgrading the existing generating fleet and connecting DR to the grid.

Primary Longer-Term Issues

- Improve transmission and generation planning on a regional basis. A regional entity with the authority to site transmission lines, allocate costs, and ensure cost recovery, would be able to create a regional transmission "backbone" that would guide developers of new generation. Regional planning along these lines could assist greatly with congestion management in the Western region.

- Resolve environmental uncertainties. Environment remains one of the major driving forces in energy development. Resolution of scientific and regulatory uncertainties would assist greatly in long-term investment decisions. The value of good scientific information is many times greater than the cost of acquiring this information.
- Promote an investment climate that encourages technology innovation. The uncertainties surrounding restructuring, and continued use of regulated cost-plus investment returns have hobbled the flow of advanced technology into the electricity infrastructure. Regulatory reform should have as one of its principle objectives the stimulation and adoption of technical innovation.
- Ensure resource diversity by creating a diverse portfolio of electricity supply options. Diversity has the advantage of flexibility and resiliency in meeting an uncertain future, cost containment through competition, and greater ability to weather supply interruptions. The U.S. has inadvertently committed its future to gas-fired generation over the next few decades, possibly setting the stage for next energy crisis.
- Redesign the structure of the marketplace to coordinate wholesale and retail markets, allow price signals to flow freely, and manage the interdependencies of gas and electricity markets.

As the electric power industry has evolved toward a market–oriented regime, a vacuum has been created in the coordinated planning needed to ensure the accountability and investment in the Western States energy infrastructure needed for a smooth transition. Deregulation's "endgame" will require fully enabled customer choice, and a network infrastructure able to support 21st Century electrical requirements. Therefore, investment incentives must reflect both short term and long term needs of the stakeholder community.

Next steps include:

- Engaging the electricity stakeholder community in a sustained initiative to resolve the power crisis in the West, and prevent similar occurrences in other parts of the country.
- Presenting the recommendations of this White Paper to state, regional and national regulatory and administrative institutions for their consideration, and making the results available to the general public.
- Seeking joint action and collaborative funding for critical assessments, plus the infrastructure technology development and deployment initiatives identified in the White Paper.

Section 7 – Western States Power Solutions Workshop Attendees
Palo Alto, California, June 7 – 8, 2001

Shan Bhattacharya	PG&E
Bill de Boisblanc	Bay Area Air Quality Management District
Ralph Cavanagh	National Res. Defense Council
Mike Cowan	Western Area Power Administration
Craven Crowell	Consultant
Michehl Gent	NERC
Paula Green	Seattle City Light
Carl Guardino	Silicon Valley Manufacturing Group
Roger Hamilton	Oregon PUC
Dick Hemstad	Wash. Utilities & Transp. Comm.
Steve Hickok	Bonneville Power Administration
Eric Hirst	Consultant
Dr. Thomas Karier	NW Power Plan. Council
John Kotowski	Global Energy Partners
Doug Larson	Western Interstate Energy Board
Ann Lyons	US EPA, Region 9
Barbara Toole O'Neil	US EPA, Region 9
Jackie Pfannenstiel	Consultant
David Rohy	Consultant
Dick Rosenblum	SoCal Edison
Terry G. Ross	Center for Energy & Economic Dev
Steve Schleimer	Calpine
Steve Schue	Portland General
Richard Sedano	Regulatory Assistance Proj
Marsha Smith	Idaho PUC
Terry Surles	California Energy Commission
Jennifer Tada	Puget Sound Energy
Shawn Taylor	Wyoming Energy Commission
Scott Turlington	State of Idaho, Governor’s Office
John Underhill	Salt River Project
Rod Webring	Energy Northwest
Mason Willrich	Nth Power Technologies
Terry Winter	California ISO

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Appendix A – Notes on Calculations

Following are short descriptions of the calculational processes and assumptions used by EPRI to estimate quantitative results such as the energy savings of end use technologies, performance improvement of transmission upgrades, and added generating capacity of power plant upgrades.

Section 3 – Methodology for Estimating Impact of Demand Response Programs

A three-step process was followed in deriving impact estimates (on page 24 of the report). First, EPRI established a baseline forecast of peak demand during the next three summers in California, Western States and the United States. Second, to avoid double counting the effect of new and existing demand response programs, EPRI developed an estimate of the impact of existing and past programs based upon market penetration rate, percent savings per customer and baseline usage. Third, three scenarios of incremental impact were developed for new demand response programs. The low case equaled the year 2000 projection. The medium and high cases were developed by using expert judgment to augment estimates of market penetration rates and unit impacts. The estimated impacts for California were allowed to be fifty percent higher on a percent-of-baseline-forecast basis than the corresponding national impacts, given the past difference between California and the US as a whole. The estimated impacts for the Western Region were interpolated to be midway between California and the US impacts.

Section 4 – Estimating the Benefits of Transmission Upgrades

The descriptions of the transmission upgrade technologies in Section 4 include an approximate benefit (generally expressed as a percentage improvement in reliability, rated transfer capacity, or capital cost). The benefits are summarized in the accompanying table.

Table A-1 – Technology Impacts of Transmission Upgrades

Technology	Impact
Implement “whole system” RCM	Up to 20% reduction in forced outages
Apply dynamic thermal modeling	10-30% increase in rated transfer capacity
Begin aggressive transmission upgrades	20-50% increase in rated transfer capacity
Introduce FACTS	20-40% increase in rated transfer capacity of specific lines; 20-40% increase in grid reliability; 20-40% lower capital cost
Create “seamless” real-time information exchange among regions	20-40% increase in power flows across regions during emergencies
Establish mandatory reliability standards	20-40% increase in grid reliability

These estimates were derived from EPRI's knowledge of the quantitative benefits provided by these technologies and include an assessment of the applicability of the technology to the California transmission system. In cases where two technologies may provide related benefits (e.g., both dynamic thermal modeling and FACTS provide benefits in the form of increases in rated transfer capacity) the benefits are not in general additive. In the example cited above, dynamic thermal modeling provides benefits in lines that are operating at or near their thermal capacity, while FACTS provides major benefits in reducing loop flows and in lines that are limited by stability. Circumstances in which FACTS can increase rating will usually not be the same in which dynamic modeling yields benefits. Conversely, if dynamic thermal modeling can increase transfer capacity by 30% in a particular line, the additional increase in thermal capacity resulting from FACTS may be relatively small. Case-specific analyses are needed to determine the total benefits achievable by any of the technology improvements, whether applied separately or in combination.

Section 5 – Generating Capacity Increases

The potential generating capacity impacts described in Section 5 represent the best estimates of the EPRI staff. The estimates are based on information obtained from the California ISO, The California Energy Commission, the Western States Coordinating Committee, EPRI's own research program, and other organizations. Information on the status of potential capacity additions, siting, and permitting are as reported by the cognizant organization as of the issue date of this report. However, these data change frequently, and the primary data sources should be consulted for updates. EPRI has also attempted to estimate data in situations where no formal data have been collected, such as the amount of DR generation in California. Ongoing and planned research efforts will provide better information on the rapidly changing status of generation capacity improvements and additions in California and the West.

About EPRI

EPRI creates science and technology solutions for the global energy and energy services industry. U.S. electric utilities established the Electric Power Research Institute in 1973 as a nonprofit research consortium for the benefit of utility members, their customers, and society. Now known simply as EPRI, the company provides a wide range of innovative products and services to more than 1000 energy-related organizations in 40 countries. EPRI's multidisciplinary team of scientists and engineers draws on a worldwide network of technical and business expertise to help solve today's toughest energy and environmental problems.

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