# Electricity Advisory Board
# Electric Resources Capitalization Concerns Subcommittee

## Competitive Wholesale Electricity Generation:
## A Draft Report of the Benefits, Regulatory Uncertainty, and Remedies to Encourage Full Realization Across All Markets

**September 2002**

September 9, 2002

Dear Electricity Advisory Board:

The members of the Electric Resources Capitalization Concerns Subcommittee present the attached Draft Report for your review in preparation for our next Electricity Advisory Board ("EAB") meeting.

This Draft Report also has been posted on the EAB's website, http://www.eab.energy.gov, and noticed in the Federal Register to allow the public full access and an opportunity to comment. It is the desire of the Subcommittee to have a full and open discussion of the Draft Report with the members of the EAB that considers any comments received from EAB members not serving on the Subcommittee, as well as the public, at our next EAB meeting.

The views and recommendations offered in this Draft Report reflect the consensus of the Subcommittee members only. As with any consensus product, the views of any individual member of the Subcommittee may differ slightly from the specific detailed recommendation contained in the Draft Report. This Draft Report is not a Department of Energy or Administration document and will not be transmitted officially to the Secretary of Energy without the consideration of any public comments received and approval of the Electricity Advisory Board.

The members of the Electric Resources Capitalization Concerns Subcommittee, listed below, are volunteers from the EAB.

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## Table of Contents

# I. Charter

The Secretary of Energy, Spencer Abraham, established the Electricity Advisory Board (EAB) in November 2001 to provide the Secretary and the Department of Energy with independent advice and recommendations on electricity policy issues. The EAB charter permits the formation of subcommittees to undertake specific studies and to provide information and recommendations to the EAB for its consideration. On April 23, 2002, the EAB approved the formation of the Subcommittee on Electric Resources Capitalization Concerns. The objective of the Subcommittee is to provide recommendations to the Board and the Secretary of Energy in support of a fully competitive wholesale market for electricity. The Subcommittee reviewed the benefits of a competitive wholesale market, identified key issues regarding financial incentives and obstacles currently inhibiting new investment, and developed a list of possible remedies to address these key issues. This Subcommittee acknowledges concurrent work being done by the EAB's Subcommittee on Transmission Grid Solutions, which will address in greater detail some of the proposed issues and remedies identified in this Draft Report.

## II. Executive Summary

This Draft Report addresses the benefits that come from a competitive wholesale electricity market, identifies key barriers to realizing its full implementation, and explores solutions that, if implemented, would re-invigorate the transition to a competitive wholesale electricity market. The Electricity Advisory Board's Subcommittee on Electric Resources Capitalization Concerns prepared this Draft Report.

The Draft Report is divided into four sections to address these issues. The first section describes the benefits of competitive wholesale markets and summarizes the regulatory issues that have affected the development of wholesale electricity markets over time. It explains how competitive wholesale electric markets contribute to price benefits for consumers by incentivizing suppliers to increase efficiencies and reduce costs. It highlights the role of competitive wholesale electric markets in driving technological innovation and expanded consumer choices, including those that will lead to cleaner sources of power and effective demand-side responses. It explains how competitive wholesale electric markets better allocate financial risks of new generation development from consumers to developers, as well as improve price signals to enable both suppliers and consumers to better respond to changing market conditions. Progress toward competitive wholesale markets is currently threatened by growing public skepticism about the feasibility of workable competition, price volatility in certain deregulated markets, and allegations of market manipulation. Nevertheless, it is critical that progress continue in order to secure the benefits of reduced costs, increased efficiency, conservation, and technological innovation that competitive wholesale electricity markets can provide.

The second section of this Draft Report illustrates how the lack of certainty in the areas of long-term infrastructure investment, utilization of risk mitigation products, corporate structure, commitment to wholesale restructuring, contract sanctity, and environmental regulation impedes access to and increases the cost of capital. The Subcommittee provides long-term infrastructure remedies to improve certainty for new generation, demand resources, and grid solutions and emphasizes the need to work with States to ensure reliable, clean and affordable energy. The Subcommittee advocates the use of risk mitigation products and suggests the promotion of policies on the State and Federal level to reduce cost-recovery uncertainty. In the area of corporate structure, the Subcommittee supports repeal of the Public Utility Holding Company Act of 1935 and its replacement with more productive approaches to consumer and environmental protection; in addition, the Subcommittee proposes reform of the Public Utility Regulatory Policies Act of 1978. The Subcommittee suggests that public affirmation by Congress and the Federal Energy Regulatory Commission (FERC) would help assure stakeholders of a policy commitment to wholesale restructuring. The Subcommittee also notes the uncertainty that exists related to the sanctity of long-term wholesale power contracts. To provide greater certainty in the area of environmental regulations, the Subcommittee supports an integrated, comprehensive, long-term, multi-emission legislation to improve the environmental performance of electric generation and allow better coordination of long-term capital investment in pollution control strategies. The net result of lack of certainty in each of the above areas is a significant limitation in capital available for investment in the energy markets. Capital constraints in energy markets subject consumers and businesses to increased risks for decreased electricity reliability, higher prices, and slower economic growth. Therefore, restoring certainty and clarifying policy objectives to reduce risk concerns is necessary to encourage capital investment.

The third section of this Draft Report identifies practical remedies that will help to provide the certainty and stability that industries need to plan and to operate successfully. The standardization of markets, as laid out in FERC's recently released Notice of Proposed Rulemaking on Standard Market Design (SMD NOPR), coupled with uniform pricing policies such as the use of Locational Marginal Pricing (LMP), will be a giant step toward removing uncertainty. In addition, the deployment of Regional Transmission Organizations (RTOs) and expansion of independent transmission providers (under the jurisdiction of RTOs) will ensure regional planning to meet the long-term needs of consumer demand. The Secretary's Electricity Advisory Board's Transmission Grid Solutions Subcommittee discusses both of these issues in further detail. Finally, load-serving entities, including regulated distribution companies, generally lack and urgently need strong performance-based incentives to play a crucial role as resource "portfolio managers," using long-term contracts for cost-effective generation and demand-side resources to reduce price volatility and ensure that energy services are both reliable and affordable. There must also be mechanisms in place to provide investment signals indicating when and where resources are needed. One mechanism discussed in this Draft Report that can support these efforts is the establishment of a long-term resource obligation on load serving entities.

Finally, a critical element necessary for investor confidence is the issue of corporate governance, including trading protocols and codes of conduct. The Subcommittee recommends more coordination among the multiple Federal agencies investigating the corporate practices of some energy companies. The Subcommittee also notes the formation of a new EAB subcommittee to address this issue and to review efforts underway by various groups.

## III. List of Acronyms and Abbreviations

| | |
|---|---|
| CFTC | Commodities Future Trade Commission |
| CROA | Chief Risk Officers Association |
| DOE | Dept of Energy |
| DOJ | Dept of Justice |
| EAB | Electricity Advisory Board |
| EEI | Edison Electric Institute |
| EPA | Energy Policy Act |
| EPA | Environmental Protection Agency |
| EPSA | Electric Power Supply Association |
| FASB | Federal Accounting Standards Board |
| FERC | Federal Energy Regulatory Commission |
| FPA | Federal Power Act |
| Grid Study | Dept of Energy's National Transmission Grid Study |
| IOU | Investor Owned Utility |
| ISO | Independent System Operator |
| ITC | Independent Transmission Company |
| ITP | Independent Transmission Provider |
| KWh | Kilowatt hour |
| LMP | Location Marginal Price |
| LMC | Locational Marginal Cost |
| LSE | Load Serving Entity |
| NAFTA | North American Free Trade Act |
| NARUC | National Association of Regulatory Utility Commissioners |
| NEMA | National Energy Marketers Association |
| NERC | North American Electric Reliability Council |
| NGA | Natural Gas Act |
| NIMBY | Not In My Back Yard |
| NOPR | Notice of Proposed Rulemaking |
| PJM | Pennsylvania, New Jersey, Maryland Interconnection |
| PUHCA | Public Utility Holding Company Act |
| PURPA | Public Utility Regulatory Policy Act |
| QF | Qualifying Facilities (under PUCHA) |
| RTO | Regional Transmission Organization |
| SEC | Security Exchange Commission |
| SMD | Standard Market Design |
| WPT | Western Power Traders |

## IV. The Benefits of a Competitive Wholesale Electricity Market

Introduction

An adequate, affordable and reliable electricity supply is essential to the U. S. economy and should be the primary goal of national electricity policy. We believe that competitive markets are the most effective means of achieving this goal.

Over the past two decades, legislative and regulatory policy changes at the Federal and State levels have significantly increased competition in the generation segments of wholesale and retail power markets through the following measures:

- incentives for entry into the generation market by new participants[1]
- market-based wholesale pricing
- non-discriminatory access to transmission
- unbundling of transportation and merchant functions

As in other industries that have undergone the transformation from regulation to competition, competitive wholesale electricity markets have provided significant benefits to consumers. These benefits have come in the form of greater reliability, competitive prices, increased innovation and choice, and a better allocation of the risks and benefits among stakeholders.

However, the United States does not yet have fully competitive wholesale electric markets that encompass all large regions. In addition, progress towards a competitive market structure is threatened by an over-reliance on spot-market energy transactions in certain re-structured wholesale markets, coupled with allegations of market manipulation. There is growing public skepticism as to whether electric power markets are capable of sustaining workable competition and whether advocates of re-structuring have overstated the alleged benefits of such competition. Similarly, there is growing skepticism among market participants as to whether markets are going to be allowed to function when prices rise or whether re-structuring is a one-way street that only works when prices decline.

[1] The Public Utilities Regulatory Policies Act of 1978 (16 U.S.C. 2601) required utilities to purchase electricity from certain types of generating units, called qualifying facilities. These facilities were owned by third parities - not the utility. The Energy Policy Act of 1992 (42 U.S.C. 13201) exempted wholesale generators from the Public Utility Holding Company Act, which allowed companies to build and acquire wholesale generating units, subject to regulation by the Federal Energy Regulatory Commission.

The U.S. electric power industry is at a major decision point regarding its continued transition to a fully competitive wholesale market for electricity. There is currently a choice between three basic policy options:

1. Continue on the path to regional competitive wholesale markets;
2. Revert back to traditional cost-based regulation; or
3. Continue with the current hybrid model of a partially regulated and competitive wholesale market structure.

This Subcommittee believes the best policy is to continue progress towards establishing a fully competitive wholesale market for electricity. In support of this policy objective, this Draft Report identifies the key drivers of the move to competitive wholesale electricity markets and the principal benefits that can be derived from a competitive wholesale market structure.

> *"The Commission believes that the viability of dependable, affordable and fair competitive energy markets rests on a sound infrastructure, balanced market rules, effective market monitoring and the efficient operation of the Commission. Restructuring of the natural gas industry cut prices by about $6,000 per household. Now, we are focused on creating a more efficient electric industry with comparable savings."*
>
> Hon. Patrick Wood III
> Chairman
> Federal Energy Regulatory Commission
> July 2002

## Key Drivers of Competitive Wholesale Electricity Markets

The vast majority of Americans believe in the value and benefits of fair competition. Industries (including airlines, natural gas, long distance telephone service and trucking) that once enjoyed near monopoly status have gone through a transition to competitive markets. The transition has not always been smooth, but in all cases, the public has benefited from the change. The range of benefits differs industry to industry but, in each case, has included improved economics for the consuming public, innovation in products and technology from the industry, and perhaps, most important, enhanced reliability and service.[2] It is also worth noting that in no case has the regulatory oversight of these industries been eliminated. Market rules, strict regulations and continued monitoring remain in full force. What has changed is that the market itself, not regulatory reviews, must encourage investment, improve service and advance technology.

By the late 70's and early 80's, legislators and regulators started a move to transform the regulated electric industry in response to increased prices in the regulated market. They also responded to the demands of customers regarding the appropriate allocation of the benefits and risks of the new market between various stakeholders. The Federal Energy Regulatory Commission (FERC) described the problem this way:

> "…expensive, large baseload plants for which there was little or no demand, came onto the market or were in the process of being constructed. Accordingly, between 1970 and 1985, average residential electricity prices more than tripled in nominal terms, and increased by 25% after adjusting for general inflation. More-over, average electricity prices for industrial customers more than quadrupled in nominal terms over the same period and increased 86% after adjusting for inflation."[3]

Below is a timeline of regulatory and other issues that have affected the development of competitive wholesale electricity markets. It is important to note from the timeline that this industry sector completed

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[2] In the ten years between 1984 and 1994, natural gas prices (in real terms) declined between 27 and 57 percent and long distance telecommunications prices declined 40 to 47 percent. In the ten years between 1977 and 1987, airline prices declined 29 percent and trucking rates declined between 28 and 58 percent. Railroad freight rates declined 44 percent between 1980 and 1990. *Economic Deregulation and Customer Choice: Lessons for the Electric Industry,* Crandall and Ellig, Center for Market Processes, George Mason University, Fairfax, Va. (1997).

[3] Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, 78 FERC ¶61,220 at 31,640 (April 24, 1996).

the bulk of the de-regulation and development of a competitive market in the mid to late 1990s.  It has been maturing at a steady pace since that time as the result of greater proliferation of regional markets.

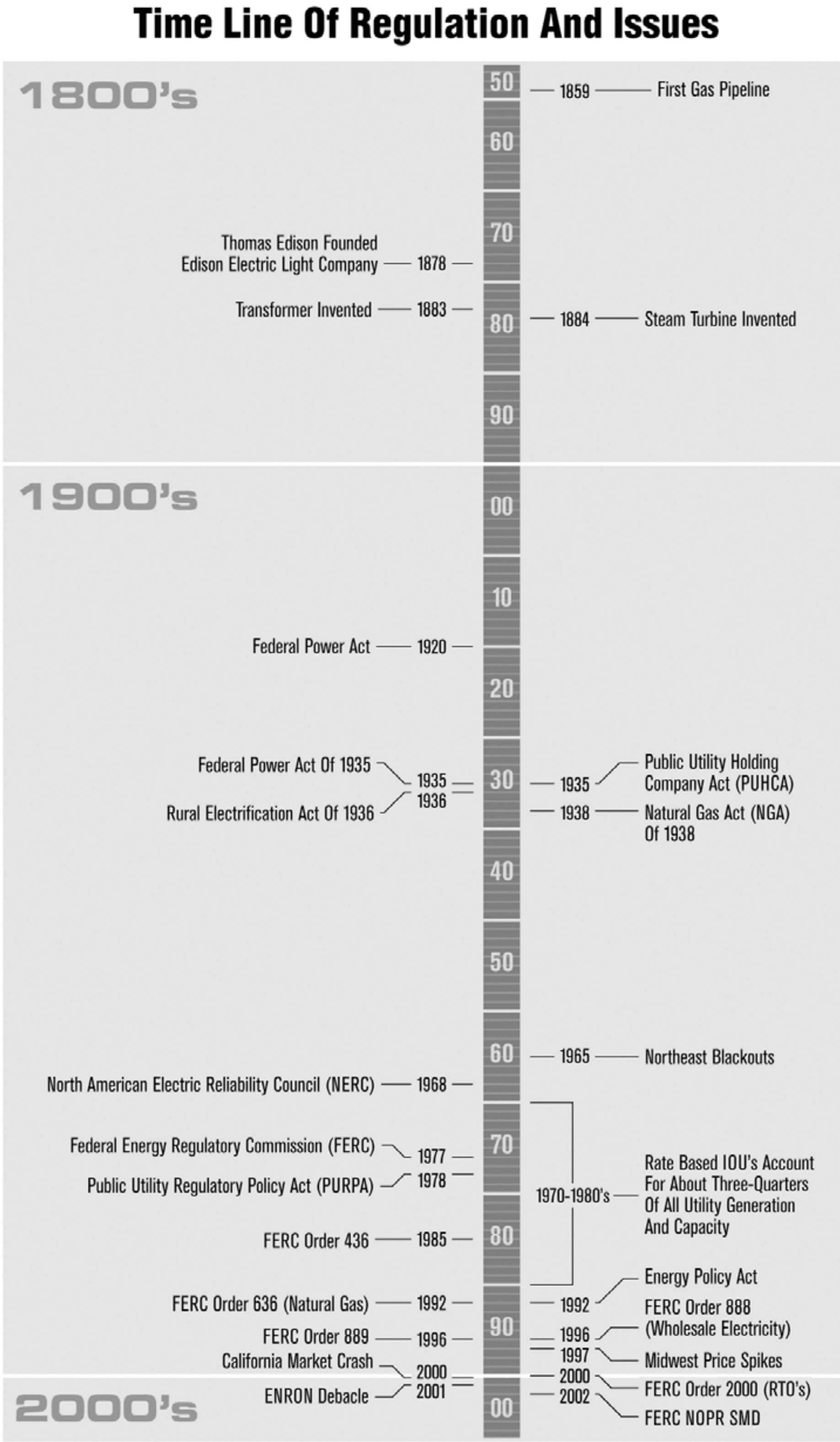


Figure 1: Timeline of Regulation and Issues

## The Price Benefits of Competitive Wholesale Electric Markets

Under cost-of-service regulation, there are fewer incentives for suppliers to increase efficiency, reduce costs, and share the benefits with consumers. The regulatory model has to rely on difficult to administer prudence reviews of cost structures and investment decisions as a surrogate for market-based outcomes. With the introduction of competitive markets, wholesale prices have dropped. Data from restructured foreign markets and some U.S. markets show that competitive electricity markets will yield lower overall costs of power supply than pervasively regulated markets.

In the U. S., electric prices fell an average of 35 percent in real terms between 1985 and 2000. A number of factors, including the gradual introduction and potential of competition, played a role in a remarkable decrease in real electric prices. For 60 utilities across the nation, average residential prices fell 31 percent and average prices for commercial and industrial customers fell 36 percent.[4]

Importantly, during this same period, consumers across the U.S. paid more uniform prices, *i.e.*, the price spread between the highest priced regions and the least cost regions narrowed substantially. This price convergence is evidence of the effects of competition. As utilities with more costly embedded supplies begin to purchase wholesale electricity from lower cost utilities and new independent power producers, prices for all customers began to converge.

A discussion of price benefits would not be complete, however, without acknowledgement and discussion of the significant price increases experienced in the western U.S. during the Energy Crisis of 2000-2001. Consumers experienced high prices, potential power disruptions and actual blackouts, and ensuing uncertainty of whether these events would occur in the future. The failure of California's re-structuring of its wholesale electricity market continues to threaten consumer and investor confidence in the evolving wholesale competitive electricity market. As a result of improper market design and a combination of factors including but not limited to record high natural gas prices and near record low rainfall in the Pacific Northwest, prices soared and blackouts and other power disruptions occurred in the West.[5] In contrast to the West, the Northeast consumer has experienced relatively stable electricity prices despite record high temperatures and drought for the 2001-2002 summer season as the result of a better designed competitive wholesale market.

The lessons of the California market re-structuring experience is not to abandon the development of truly competitive wholesale markets but to ensure that market rules and structure are properly designed and executed.

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[4] 2000 Data Update: Assessing the "Good Old Days" of Cost-Plus regulation, Boston Pacific Company, Inc., Washington, D.C. (2002). Even in year 2000, which was marked by supply disruptions in California, on average residential prices fell by 1%.

[5] *The National Transmission Grid Study* at p. 5, U.S. Department of Energy (May 2002).

The PJM Interconnection, the New York ISO and ISO New England all operate real time energy markets that select generating units based on competitive bids, subject to reliability constraints. These markets are often studied as models for competitive electricity markets. Although all three markets operate competitively, cost-benefit studies by PJM ISO, the New York ISO and Energy & Environmental Analysis (EEA) found that wholesale prices could be lowered through more robust competition across regions with standard market design.

Currently, wholesale electric markets in the U. S. do not yet extend over large regions or all areas of the nation. Further, the rules for conducting wholesale electric sales and operations differ from region to region. In February 2002, the Federal Energy Regulatory Commission published an analysis by its consultant, ICF, of the costs and benefits of regional markets, where wholesale suppliers would compete to serve customers under a more standard set of market regulations.[6] ICF's models predicted regional competition among generators would save $40.9B by 2021 – 3.8 percent over a period when all forecasters predict that demand will rise and new generation will have to be added. Importantly, competition increases generator efficiency. ICF's model predicts a six percent improvement in the heat rates of fossil fuel units, which indicates the ability to conserve fuel (primarily natural gas).[7]

Additional evidence of the benefits that can be derived from the development of competitive electric markets was provided in the *National Transmission Grid Study*, which found that "today's wholesale electricity markets save consumers nearly $13 billion per year in electricity costs."[8]

## Competition Drives Technological Innovation

In addition to lower prices, competition encourages increased innovation and expanded customer choices. Competition in the wholesale electric market has already provided incentives for companies to develop cleaner, more efficient technologies – innovations that will dramatically decrease emissions and make better use of more environmentally friendly fuels. Competitive wholesale suppliers offer customers new ways to reduce risk and stabilize retail prices through new product offerings and customized contracts.

Competition can lead to true demand-side responses. Truly competitive wholesale markets provide more accurate price signals that allow customers to adjust their consumption levels to reflect seasonal and time-of-use variations in the cost of power production. Demand responsiveness can reduce price spikes and can allow for lower levels of installed capacity without any loss in system reliability. According to ICF, competition within a regional transmission organization (RTO) can encourage more efficient use of fuel at

[6] *Economic Assessment of RTO Policy*, ICF Consulting, Fairfax, Virginia (February 26, 2002) at vi.
[7] ICF conducted several sensitivity scenarios, one of which assumed that heat rate would improve 1% per year for six years. The Subcommittee notes that overall, there has been improvement in heat rate.
[8] *The National Transmission Grid Study* at p. 19, U.S. Department of Energy (May 2002).

power plants. Indeed, the largest potential savings from competition are programs that encourage customers to reduce demand at critical times. The ICF study predicts that demand reductions through the RTO could create $60B in savings by 2021 – 5.6 percent over the period. In order to realize this potential, FERC and State regulatory authorities will need to establish mechanisms that allow both large and small demand response resources to participate effectively in electricity markets.

When true competitive markets are created, investment in cleaner, more efficient units should lead to the displacement of older, less fuel-efficient units (though to date, new plants have largely been additions to the power plant fleet rather than substitutions of existing plants). The older, more costly units will be relied upon only during peak demand periods. This competitive substitution can result in both environmental and consumer benefits. New power plants are often 100 times lower in NOx emissions and 1,000 times lower in SOx emissions per megawatt-hour (MWh) generated than the U.S. fossil fuel average.[9]

Competition Better Allocates Risks and Improves Price Signals

A key benefit to consumers in the competitive market is that many of the financial and operational risks of power plant ownership and operation can be assumed by private developers whose earnings depend on their ability to generate power competitively.

These private developers and owners of merchant generating plants directly assume the traditional risks associated with the construction and operation of their facilities such as paying for surplus capacity, the technological obsolescence of utility plants, plant performance, fluctuations in fuel prices and certain cost overruns in plant construction. In turn, many of these risks are shared through contract with fuel suppliers, equipment suppliers and construction contractors. One of the primary benefits of competition is that it provides all participants in electricity markets, including consumers and utilities that serve them, with a variety of mechanisms for controlling risk and for transferring risk to the parties that are best equipped to manage it. Thus, merchant power offers traditional investor owned utilities with portfolio alternatives to better manage risks. Traditionally, the only option available to meet growing demand was to build power plants that were then rolled into rate base. With the advent of competitive markets, utilities can offset some of their demand needs by entering into long-term contracts of five years or more with merchant plants,

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[9] The emission displacement for $SO_2$ does not literally create overall emission reductions. $SO_2$ emissions from the power generation sector are "capped" by the Clean Air Act Amendments of 1990 Title IV Acid Rain Program. This program applies an allowance trading system that limits the overall emissions of $SO_2$ but allows affected units to trade emission allowances. The result of this program is that emission reductions at one location can be shifted to an increase at another location. Thus, when new combined cycle plants displace existing generation with lower emitting generation, the displaced $SO_2$ emissions can be emitted by another existing plant and there is no absolute reduction in $SO_2$ emissions. Since the cost of allowances is a variable cost that affects the cost of electricity, the construction of new plants reduces the overall cost of compliance with the $SO_2$ limits. There is a similar cap and trade program for NOx emissions in the Northeast that applies only during the summer (May through September).

creating a broader and more attractive array of options than just utility construction and ownership of power plants.

Competitive markets also provide superior price signals to motivate suppliers and customers to respond appropriately to changing market conditions. Market-based price signals attract new supply and moderate consumption on the basis of customer need and willingness to pay rather than administratively determined outcomes, *e.g.*, through prudence reviews. More accurate price signals result in timely market entry by new generators, more efficient siting of new generation and transmission facilities, and selection of the most efficient generation technology for a particular market niche. Since 1997, competitive suppliers have added 61 gigawatts of new generation capacity in the United States. They have also purchased billions of dollars of existing assets, making those assets part of the competitive generation portfolio and relieving consumers of the risks and costs of continued operation. The competitive suppliers have ownership in 36% of all electric plant capacity and are the source of 90% of the new power plant development.[10] However, for the benefits of competition to be realized markets must be allowed to function with minimal and predictable regulatory intervention. Demand-responsiveness is muted when price caps are used to control price volatility. Changes in market rules create uncertainty that discourages incremental generation investment. Such actions threaten to undermine progress towards a fully competitive wholesale market.

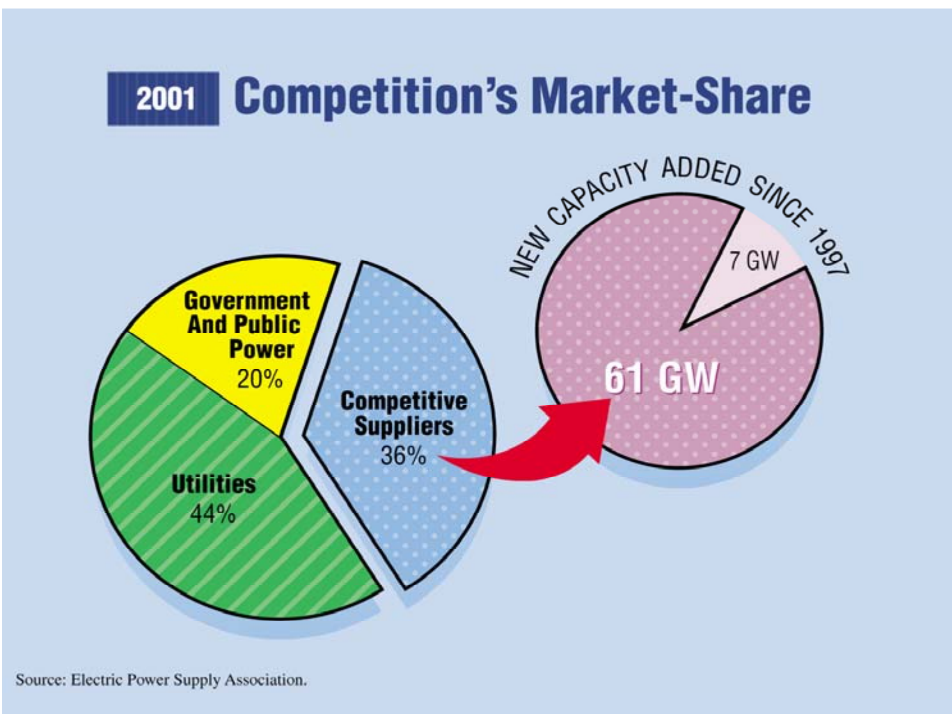


Figure 2: 2001 Competitive Market Share

[10] Electric Power Supply Association literature.

Summary

The introduction and continued development of competitive wholesale electric markets have provided significant benefits to the U. S. economy. The continued evolution of competitive wholesale electric markets that encompass large regions and standard market rules for operating competitive regional markets is critical. FERC's cost-benefit analysis predicts that large, regional markets with standard market design will unlock $40.9 billion of additional savings by 2021 -- a 3.8 percent decrease over a period when all forecasters predict demand will grow. Competition also increases efficiency and conservation. FERC's analysis predicts a 6 percent improvement in the heat rates of fossil fuel units and $60 billion dollars in savings -- 5.6 percent -- from new demand reduction mechanisms that can be incorporated into regional markets.

The benefits of wholesale electric competition have been proven by past regional gains. It is therefore important that the nation implement wholesale electric competition in larger regional markets, using standard market rules in order to realize national benefits. Therefore, the Subcommittee on Electricity Resources Capitalization Concerns respectfully recommends that the Secretary of Energy:

**Pursue policies that provide continued progress towards establishing a fully competitive wholesale market for electricity.**

## V. Regulatory Uncertainty and its Effect on Capital Formation in the Power Industry

Introduction

A crisis in confidence---prompted first by the California energy crisis, and exacerbated by the collapse of Enron, the questionable practices of Arthur Anderson, and the downgrading of credit for market participants by rating agencies, and the ensuing investigations into corporate business practices---has driven capital away from necessary investments in energy infrastructure. This section describes areas where lack of certainty exists, how regulatory uncertainty has dramatically impacted access to and cost of capital, and outlines remedies to address these issues.

Regulatory uncertainty is comprised of three distinct but related components:

1. A lack of clarity on the part of market participants as to the pace and scope of restructuring;

The perception by market participants that markets will only be allowed to function when prices remain low, not as prices rise to reflect commodity scarcity, and that government will intervene post-facto to abrogate or reform contracts; and

2. The uncertainty regarding environmental regulatory requirements that may be imposed on the electricity industry.

If one accepts the basic assumption that markets reflect the value and earning potential of assets, then it is easy to understand why any uncertainty undercuts the investment in and development of those assets. This uncertainty amplifies the typical project development challenges in the energy industry, which are characterized by long-term planning horizons, significant asset expenditures, and commodity price risk.

The energy industry is capital intensive. This is especially true on the generation side of the equation that is gradually being restructured from a rate-base/rate of return model to an investment model. The following are some of the basic elements involved in the investment evaluation process:

- **Power plant development projects require substantial funding and have lengthy planning, construction and start-up processes.**
  - Large-scale projects, 600-1000 megawatts, can cost up to $800 million.
  - Licensing, zoning, permitting and construction processes for completion of the physical plant and power lines extend over a 3 to 20 year period.

- **Numerous Federal, State and local agencies have oversight with over-lapping jurisdiction.**
  - Unclear dispute resolution processes create unavoidable project delays and added costs.
  - License application and project siting processes lack standardization across the States.
  - "NIMBY" mentality inhibits effective resolution of infrastructure issues.
  - Environmental and legal challenges are complex and substantial.

- Appellate actions from consumer groups and private citizens create additional risk.

- **Energy supply and delivery infrastructures that do not keep pace with growing consumer demand create exceptional commodity price volatility.**
    - Price volatility for natural gas can alter the financial analysis for power plant projects.
    - Boom and bust cycles inhibit consistent investments in alternative energy solutions such as fuel cells, solar and wind power technologies.
    - Demand response and energy efficiency programs are typically created during crisis periods and are utilized only as "stop-gaps" during emergency periods.

Substantial capital and other resources are required to mitigate these risks and to build the infrastructure necessary to provide reliable, efficient, and clean power to our country.

Uncertainty drives up the cost of capital because creditors and lenders assessing the risks associated with the uncertainty compensate by making resources more difficult and more expensive to acquire. Therefore, eliminating or minimizing the regulatory uncertainty is critical in order to help ensure that an adequate amount of capital is available to keep the power flowing at affordable rates.

### *A. Lack of Clarity Regarding the Pace and Scope of Restructuring*

#### *1. Long-Term Infrastructure Investment*

Capital formation challenges affect the development of new generation, demand-side resources, and grid solutions. Obstacles to investing in these three areas must be addressed to ensure reliable, clean and affordable energy.

Without a reasonable degree of certainty, capital will not flow to infrastructure projects. Without capital, infrastructure will not develop, or worse, will deteriorate. Energy infrastructure is essential to the economic well-being and progress of the nation.

***New Generation***

Regulatory uncertainty surrounding the development of new competitive generation affects siting issues, tax issues, transmission service, and it can impede market signals that should be driven by normal supply and demand conditions in a competitive marketplace.

Market signals affect reliability and the behavior of generators and consumers. Mechanisms such as price caps and other market mitigation mechanisms distort market signals. While price caps are politically attractive and appear to protect consumers in the short term, there is a counter argument that the imposition of such mechanisms, along with other factors discussed in this Draft Report, has hindered the development of new generation, and may even create higher prices for consumers in the long term.

For example, both generation and transmission price signals affect the development and siting of natural gas-fired peaker plants that compose an important segment of the new competitive power supply. Peaker plants are relatively easy to build and can be turned on and off quickly to meet a spike in demand for power. Peaker plants only run several hundred hours a year or less. Within these hours, they fill gaps in the market that occur such as consumer load increases due to weather or where there are planned or emergency plant outages.

Companies are able to make the peaker economics work because these times of high demand and outage periods cause prices to rise substantially and allow owners to recover the fixed cost of the peaker during these limited hours of their operation. However, if price caps are a real or perceived threat, developers of these plants will not be able to demonstrate the economic returns that support the building of this type of infrastructure.

By artificially dampening market signals with price caps and other regulatory mechanisms, investment in economical sources of new supply is limited. One solution in such a situation could be the implementation of a capacity market in order to provide a revenue stream to the peaker owner so that its fixed costs are recovered while, at the same time, energy price volatility is minimized. This remedy is discussed in greater detail later in this Draft Report.

Another obstacle to new competitive generation is uncertainty associated with siting and regulatory approval for the construction of new generation facilities. Siting generation facilities is primarily a State or local responsibility and a process engendered with various land use issues. Risks of NIMBY objections, which sometimes unilaterally affect the decision making process and have at times resulted in the under development of necessary power assets, affect capital formation. Similarly, inconsistent application of policy or regulatory guidelines among the States and unpredictable timeframes resolving issues make access to capital more difficult and more expensive. Without Federal leadership fostering cooperative State behavior, this impediment will continue to negatively affect investment in and development of new competitive generation.

New competitive generation development is also hindered by having to adhere to longer Federal tax depreciation schedules than other similarly situated capital-intensive projects in the pulp and paper, steel, lumber, automobile and shipbuilding industries.

Plant assets in some of these other industries are depreciable for Federal income tax purposes over 7 years. Chemical plants and facilities for the manufacture of electronic components and semiconductors can be depreciated over 5 years. Despite the fact that these facilities are users of electricity generated by competitive wholesale energy suppliers, electricity generation assets must be depreciated over 15 years --- more than twice the length of the facilities mentioned above. To efficiently meet our nation's energy needs, the competitive electric generation industry requires the same ability that other industries have to more rapidly depreciate assets for Federal income tax purposes.

Finally, uncertainty about the ability of new competitive generation to transmit power to the market on fair terms affects capital formation. This issue encompasses both the interconnection of generation to the high voltage grid as well as the transmission of bulk power over that grid. Grid access is vital, but it must start with interconnection access.

Although FERC has made it clear in Orders Nos. 888 and 889 that there should be non-discriminatory open access to transmission services for all energy suppliers, market design flaws have hindered the full transition to a competitive wholesale power market.

One of those flaws is the lack of standardization of the interconnection rules and practices. Another is the lack of transmission pricing methodologies that can encourage grid congestion by paying transmission owners a premium for the use of a congested grid. A standard market design for transmission services is required to alleviate the uncertainty associated with these issues.

***Remedies:***

a) Congress should provide FERC with the necessary authority to develop a national policy and regulations that promotes accurate market signals and attracts the capital for needed new generation supply.
b) Congress should encourage FERC to define the mechanism and the criteria that must be met to invoke market mitigation measures.
c) Federal income tax laws should be changed to allow electric generation facilities to be depreciated over 7 years and to provide comparably favorable tax treatment for investments in cost-effective alternatives to generation facilities.
d) DOE should help to coordinate States (and where applicable Federal agencies) to achieve economically rational generation siting system with an emphasis on regional reliability.
e) FERC's Proposed Rule on Standard Market Design (SMD) and Standard Generator Interconnection Rules should help provide certainty. The principles of the SMD and Interconnection Rules should be applicable to all transmission owners within an RTO and to independent transmission providers (ITPs) where RTOs have not yet fully developed. Legislation is needed to ensure that non-jurisdictional entities (e.g., electrical cooperatives, municipal power suppliers, PMAs), which comprise a significant portion of the transmission market, will be required to comply with the SMD.

***Demand Resources***

The NAFTA Commission on Environmental Cooperation reports that utility sector investments in demand-side resources, including energy efficiency, dropped significantly during the 1990s, showing a strong record of progress in reducing energy service costs; unfortunate results include unnecessarily high energy bills and pollution emissions.[11]

Numerous market barriers continue to obstruct cost-effective investments on the demand side. Electric distribution companies have a proven capacity to help solve the problem by integrating incentives and programs in their resource portfolios, but few have any financial incentive to do so today.

***Remedies:***

a) State regulators should be encouraged to give distribution companies performance-based incentives that encourage cost-effective demand-side investments in their electric-resource portfolios.
b) Rules for the capacity market should be set so that demand-side resources are treated on a non-discriminatory basis.
c) Regulators should be discouraged from taking actions that artificially depress price signals that would otherwise encourage demand reduction.

***Grid Solutions***

Robust regional transmission grids are necessary to provide reliability and support commercial activity. As noted in the Department of Energy's National Transmission Grid Study ("Grid Study"), there has been a lack of investment in the development of new transmission lines to relieve significant "transmission bottlenecks". Among the reasons for this lack of investment is a measure of regulatory uncertainty associated with transmission siting and who is responsible for paying the costs of the investment.[12]

Siting and permitting large-scale transmission projects is a controversial and politically charged matter. As a result of prolonged uncertainty and unpredictable timeframes, the nation's transmission system has serious vulnerabilities. More coordinated efforts among the various agencies and better planning can help reduce some of the difficulties.

Regional transmission system planning is expected to be one of the critical functions of RTOs. FERC's Order No. 2000 was intended to encourage the formation of RTOs based on the voluntary participation of

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[11] Wall Street Journal, June 14, 2002.

[12] The Subcommittee notes that a variety of grid solutions other than transmission line expansion exist that can also be used to expand and improve the flow of electricity from source to end-user. For example, grid solutions include advanced technological innovations such as the use of composite materials to reconductor existing lines, phase shifters to redirect current flows, mobile static var compensators to maintain voltage and power factors, and hardware and software applications that are used to create a "smart" grid that can manage and adjust itself. Throughput can also be improved through innovative grid management techniques, such as live line reconductoring and the use of dynamic equipment ratings.

transmission owning utilities by December 25, 2001.[13] The development of RTOs, however, has been impeded by uncertainty regarding the economic impacts of RTO formation and the extent of FERC's authority over RTOs. Investors, market participants and transmission owners will be inhibited about making transmission decisions until the consequences of Order No. 2000 are better understood. As RTOs are more firmly established, investors and lenders should be better able to evaluate planning strategies and assess risks.

Another aspect of uncertainty related to grid solutions is the allocation of costs associated with connecting new generation to the grid. Historically, vertically aligned energy companies owned and controlled the transmission lines and were responsible for the costs of other entities to interconnect with existing transmission. These connections were typically minor and infrequent. However, due to the advent of wholesale competition with its attendant restructuring of generation assets away from the vertically-integrated parent utility, a significant amount of new merchant generation has been built. The cost to connect to the grid and difficult decisions about allocating costs among transmission owning entities, market participants, end-users and generation owners must be resolved.

Greater certainty will be available once FERC makes a final decision about generation interconnection standards and cost allocation in the context of its Generation Interconnection Terms, Conditions and Pricing rulemaking or its SMD NOPR. Until a clear resolution is achieved, however, companies will hold back investing in the grid solutions. Adequate cost recovery must be evident and the ability to generate a fair profit must be possible. FERC has already made some efforts to adopt a policy of higher rates of return and shorter depreciation schedules when justified by cost effective grid enhancements.

The EAB's Transmission Grid Solutions Subcommittee tackled these very issues of regulatory uncertainty and made the following findings:

1. The Grid Study identified a number of initiatives to relieve transmission bottlenecks by completing the transition to competitive regional wholesale electricity markets, including the formation of RTOs. The Transmission Grid Solutions Subcommittee supported the formation of RTOs and FERC's initiative to require RTOs to adopt security constrained locational marginal pricing (LMP) in order to facilitate more competitive wholesale markets.

2. In order to address the concerns with transmission cost recovery, the Transmission Grid Solutions Subcommittee recommended, "Those who cause the system to incur increased costs should bear the responsibility of paying them. Those who create benefits by enhancing the system should also reap those benefits." As a general matter, the Transmission Grid Solutions

[13] http://www.ferc.fed.us/Electric/RTO/post_rto.htm

Subcommittee suggested that where the building of new transmission facilities, or an upgrade of existing facilities, primarily benefits the system as a whole, the cost of those facilities should be borne by all users of the transmission system and "rolled-in" to system-wide rates. In contrast, where there is not a system-wide benefit for the customers that have paid for the existing facilities, the cost of the new facilities should be borne by the individual customer, or customers, who benefit and thus should be "incrementally priced". The Transmission Grid Solutions Subcommittee urged FERC to implement a policy that reflects these cost recovery principles.

3. Since the cost recovery of transmission investments crosses State and Federal jurisdiction, the Transmission Grid Solutions Subcommittee recommended that there should be a dialogue between FERC and the relevant State regulatory bodies to address these issues early in the planning process. The purpose of this dialogue would be to establish a formal agreement between the States and FERC on the key principles to govern transmission cost recovery.

4. With respect to transmission siting of "National Interest Bottlenecks", the Transmission Grid Solutions Subcommittee recommended a process including DOE, FERC, and the States. DOE would be responsible for identifying these National Interest Bottlenecks. FERC would take the lead on the cost-benefit analysis of these transmission investments and the "back-stop" authority to grant a certificate of public convenience and necessity to an applicant proposing a solution to the bottleneck. In defining the back-stop for FERC, the Transmission Grid Solutions Subcommittee suggested that FERC should have the authority to act if a State, States, or another Federal agency has failed to act on the pending application within 12 months of receiving the application. All other transmission projects that do not fall into this category of "national interest" will continue under existing State and Federal siting review.

***Remedies:***

a) Congress should encourage the States to establish regional siting review and approval processes that accommodate interests in grid reliability and economic stability. In cases in which a State or States cannot reach a solution within a reasonable time and the national interest is affected, Congress should empower FERC with limited siting authority for transmission. The Transmission Grid Solutions Subcommittee addressed this remedy proposal in its Draft Report.

b) Congress should confirm FERC's authority to mandate the participation of transmission owning utilities in FERC approved RTOs or ITPs by 2003.

c) FERC, in conjunction with the States, should continue its policy of increased rates of return on cost-effective grid solutions (beyond cost based rates) to stimulate investment.

d) FERC's expected completion of its rulemaking on Generation Interconnection Terms, Conditions and Pricing in calendar year 2002 will help to provide certainty.

e) Market rules must not allow transmission operators to profit from transmission congestion.

### *2. Utilization of Risk-Mitigation Products*

Historically, cost-recovery pricing for regulated utilities allowed them to pass costs plus a regulated rate of return to the consumer. The advent of performance based rates and restructuring of the wholesale markets has made utilities more sensitive to market-based pricing, the influence of price caps and other market signal inhibitors.

Despite the trend towards market-based pricing, public utility commissions and other government officials have kept regulations in place that prevent utilities from taking advantage of all the tools available to assist them in making prudent business decisions about the amount of price and portfolio risk they will undertake.

Risk-mitigating products such as hedges have been proven effective in many industries as a way to manage quantifiable risk and to enable companies and individuals to operate with price certainty. Agriculture has utilized risk mitigating products, or derivatives, to fix their known costs and to stabilize their cash flows for many years. This practice has seen a slower rate of adoption with utilities. One reason for this is that some utilities are hesitant to use these types of tools for fear of being determined by regulators, after-the-fact, to have been "wrong" about the market and consequently forced to pay for the cost of the derivative themselves.[14]

Lack of acceptance, general reluctance and tight commission restrictions regarding utilities' use of risk-mitigating products drive up the cost of doing business. Without the use of these tools, customers and shareholders are at risk for volatile commodity prices that could be managed by the utility through the use of risk management products that are widely available in the marketplace.

In addition, if risk mitigating products are used, banks and other lenders, already comfortable with the use of such tools, would have a better understanding of the fixed costs associated with energy projects and may be more willing to lend at better rates for these long term projects.

Another particularly destructive source of uncertainty involves distribution utilities' traditional responsibilities as electric-resource portfolio managers, including their capacity to execute long-term contracts for a balanced combination of new generation, demand-side solutions, and transmission infrastructure. Given concerns about cost recovery and the lack of incentives for effective performance, many generation and distribution companies are understandably reluctant to make long-term commitments for fuel supply, energy efficiency improvements and physical assets. Appropriate performance-based

[14] Gas Daily, June 10, 2002.

incentives at the State-level may help to provide an overdue revival of emphasis on resource portfolio management and related investments throughout the electric distribution sector.

***Remedies:***

a) Congress should consider clearly defining appropriate oversight authority of derivatives among the Securities and Exchange Commission (SEC), the Commodities Futures Trading Commission (CFTC) and FERC by the end of 2002.
b) EAB members should provide additional education tools and partner with large lending institutions and organizations, such as National Association Regulatory Utility Commissioners (NARUC), to help government entities understand the use and benefits of these products.
c) Federal agencies, in conjunction with the States, should promote policies that will allow companies to utilize risk-mitigating products without concern for later disallowances. The abuses of entities like Enron should not lead to the hobbling of the energy sector by denying access to *bona fide* financial instruments, of known quality, obtained as a function of prudent business practice.
d) Portfolio management that includes the use of risk management products, long-term resource and sales contracts and infrastructure investments should only be reviewed for prudency on a prospective basis, and efforts such as contract pre-certification processes should be developed to avoid the potential for after-the-fact second guessing.

### *3. Corporate Structure*

The energy industry is also subject to regulatory controls on its corporate structure pursuant to the Public Utility Holding Company Act of 1935 (PUHCA) and the Public Utility Regulatory Policies Act (PURPA). Both of these acts affect the ability of energy companies to access capital.

***PUHCA***

PUHCA, which is administered by the SEC, was designed to limit the business activities of public utility holding companies by imposing geographic integration requirements and ownership constraints. Under PUHCA, investors who do not qualify for any of the statutory exemptions from registration under PUHCA, cannot provide 10 percent or more of the equity in utility projects without having to become registered utility holding companies under PUHCA.

The responsibility of being a registered holding company and the associated restrictions (such as the obligation on the investor to divest all of its other businesses unless they are integrated with, or functionally related to, the utility project) strongly deters capital investment in energy infrastructure projects. For example, a AAA-rated holding company like Berkshire Hathaway, which would like to invest up to $10 billion in energy, is restricted from doing so by this law.[15] PUHCA may also hinder the formation of RTOs if multi-state transmission companies fear that PUHCA restrictions would make their efforts uneconomical.

There are arguments against PUHCA repeal that suggest that consumers and the environment would be harmed. Opponents of PUHCA repeal aver that without PUHCA, utility holding companies would merge into huge multinational corporations that would be beyond regulation and would impose higher rates to cover cross-subsidization efforts and greater business risks. Opponents also worry that large companies would rely primarily on fossil fuel plants and drive renewable and energy efficient plants out of the market.

The environmental consequences of PUHCA repeal are more easily addressed than the issue of multinational presence in the United States. The Subcommittee believes that these concerns can be addressed by a variety of means, including but not limited to improved financial disclosure and merger review rules, more complete internalization of environmental costs and the removal of barriers to increased capital investment in competitive wholesale power markets.

***PURPA***

PURPA was designed to promote the development of specially qualified small power producers and cogeneration facilities known as Qualifying Facilities (QF). Under PURPA, investment is hindered due to restrictions on the ownership of QFs.

PURPA regulations prohibit utilities from owning more than 50 percent of a QF. PURPA requires electric utilities to purchase electricity generated by QFs at the utility's avoided cost. Avoided cost is the cost the utility would have paid to generate the same electricity itself or to purchase it elsewhere. PURPA also requires electric utilities to sell QFs back-up power at just and reasonable rates and without discrimination.

While PURPA should be credited for promoting the development of QFs and fostering competition in electricity markets, the purchase obligation under PURPA today has also resulted in above-market costs. The PURPA QF "subsidies" and protections enacted in 1978 are no longer necessary, and the ownership limits impose unnecessary transactional burdens without advancing any legitimate public purpose.

[15] Repeal of PUHCA Once Again Pushed as Solution to Utility Dilemma, http://www.energynews.com.

***Remedies:***

a) Congress should repeal PUHCA and address PUHCA concerns through other means, including but not limited to improved financial disclosure and merger review rules, more complete internalization of environmental costs and the removal of barriers to increased capital investment in competitive wholesale power markets. Access to public utility books and records must be sufficient to permit effective protection of consumer interests and accurate monitoring of business endeavors.

b) Congress should reform PURPA prospectively by eliminating ownership restrictions and encouraging more flexible and market-oriented alternatives in place of current PURPA mandatory purchase and sale requirements.

### *4. Commitment to Wholesale Restructuring*

The necessary and continuing investigations into the questionable actions of a limited number of energy companies continue to foster a lack of confidence in the entire industry. It is also inhibiting progress on issues that will improve the wholesale electricity marketplace. In addition, analysts and credit rating agencies are changing the rules on how they value and treat the industry and its commercial paper. Multiple states have put issues related to the restructuring of the power industry "on-hold" while others that are in the early stages of operating in a competitive environment are re-looking at their current choice programs.

The result of this abundant and very public lack of confidence, which is reinforced daily by the national news, is that banks and other lenders are choosing to take a wait-and-see attitude before they commit to funding investments in this sector.

While a degree of credit tightening and investment scrutiny is not only understandable but also prudent, it is vital that capital investments continue to be made in energy infrastructure. The restoration of investor confidence is critical to the rehabilitation of investment markets generally, and most particularly with respect to the energy sector. The demands of the industry are long-term. The industry, in concert with government, must educate investors, end-users, and security analysts by providing clarity and stability in areas that inhibit capital formation and the further development of competitive energy markets.

***Remedies:***

a) SEC, DOJ, FERC, and the CFTC must isolate instances of wrongdoing and move quickly to implement solutions to provide safeguards. FERC and the SEC particularly must be provided with substantial investigative and enforcement authority.

b) The use of groups such as the National Futures Association to assist in overseeing and policing energy trading issues should be considered.

c) Congress and FERC must publicly reaffirm their commitment to wholesale energy restructuring in legislation and policies.

*B. Uncertainty in Contracting*

A significant concern to market participants is the question of certainty in the sanctity of long-term wholesale power contracts due to post-facto government intervention to consider the abrogation of the contracts. The purpose of such a bilateral long-term contract is to provide a risk mitigation tool to the two parties in lieu of a reliance on the spot market. As described in the "Utilization of Risk Management Products" subsection, the use of a bilateral contract reduces the risk of the two parties to the volatility of the spot market. State regulators need to play a critical role in supporting Load Serving Entities (LSEs) who choose to use the tool of long-term bilateral contracts to reduce risk and to protect consumers.

A party to a bilateral contract should not be able to abrogate contractual payments simply because the spot market moved unfavorably. Each party recognized this risk upon entering the bilateral contract. The abrogation of bilateral contracts will have a chilling effect on this market as participants will have doubts as to the validity of their contract. Likewise, investors in energy companies will have doubts on the ability of the companies to recover the revenues associated with their contracts. This will ultimately reduce the amount of capital available for new generation investment.

The Subcommittee notes that FERC is currently endeavoring to instill a level of uniformity to the standard of review for modifications to market-based rate contracts in order to provide the market greater certainty.[16] FERC recognizes that it is critical to promote stability of power contracts to meet future energy needs. The Subcommittee supports the existing law which requires application of the public interest standard of review to all contracts other than those in which both parties have expressly agreed to reserve their rights to modify a contract under the lower just and reasonable standard. The Subcommittee supports the statement included by Commissioners Brownell and Breathitt that "investors will not participate in a market in which disgruntled buyers are allowed to break their contracts…."

[16] On August 01, 2002 FERC issued a Notice of Proposed Policy Statement (NOPPS) regarding the standard of review that must be met to justify proposed changes to such contracts. The NOPPS solicits comments on the application of the Mobile-Sierra doctrine, which sets a higher level of review of contracts (*e.g*., the public interest standard), or whether to set a just and reasonable standard of review if strict language is not inserted in the contract at the time of negotiation to bind the public interest standard.

***Remedies:***

a) FERC must implement a Standard Market Design as contemplated in its NOPR. This should assist in establishing a fixed set of rules by which parties can enter future contracts with a known landscape. In its SMD NOPR, FERC states, "Central to Standard Market Design is its reliance on bilateral contracts entered into between buyers and sellers." In addition, FERC should support the Mobile Sierra standard of review for all contracts under their NOPPS in order to provide market certainty to meet energy needs.

b) Federal agencies, in conjunction with States, should promote policies, such as contract pre-certification proceedings, that will allow companies to enter bilateral contracts without concern for later disallowances or refund orders.

*C. Uncertainty in Environmental Regulatory Requirements*

The energy industry has invested billions of dollars over the last twenty years to help the environment and control pollution, with a particular emphasis on the improvement of air quality. This money was well spent, and has brought about positive environmental results, including significant reductions in emissions of sulfur dioxide.

While individual members of the Subcommittee have different views about many aspects of environmental regulation, we all support the increased use of integrated, multi-pollutant reduction strategies relying where possible on market-based mechanisms for minimizing the costs of achieving the environmental goals.

The regulatory environment can and should be more certain and science-driven, allowing better coordination of long-term capital investment in pollution control strategies and less reliance on ad hoc litigation and regulatory amendments.

***Remedies:***

a) DOE and EPA should develop integrated, comprehensive, long-term, multi-emission legislation that establishes reasonable regional and local caps on pollutants.

b) Adoption of integrated, comprehensive, long-term, multi-emission legislation should establish the foundation for a consensus-based redesign of the new source review program, which addresses obligations of generation owners contemplating plant upgrades or expansions that would result in increased emissions of regulated air pollutants.

c) SEC (FASB) and FERC should update tax and financial incentives to permit faster depreciation on pollution control devices.

**d)** EPA should take an active lead in providing clarity and uniformity between Federal and State governments in regards to environmental concerns.

*Summary*

This section has identified key areas where the "uncertainty" around regulation is adversely affecting capital formation within the power industry. The problem we face is one of both practice and perception: reformed and restructured energy markets are misperceived as an open arena for shady deals, the unbridled exercise of market power, a playground for regulators promulgating ever-changing market rules and as a graveyard for investors' hopes.

This crisis of public and investor confidence must be addressed by a re-commitment to open markets, appropriate government and regulatory distance from contract formation and execution.

The public at large and the investment community must not doubt where government stands with respect to the issues set forth in this Draft Report. Restoring certainty and clarifying government's and other agencies' roles will reduce the risk premiums associated with energy projects and free up capital that can be used to provide the country with clean, reliable power.

## VI. Solutions to Continue the Re-structuring of Energy Markets

In order to reap the benefits that come from the realization of a fully competitive wholesale electricity market, practical remedies are needed to provide the certainty and stability necessary for investment in and successful operation of energy infrastructure. There must be mechanisms in place to provide the investment signals that indicate where and when resources are needed. One mechanism is the standardization of regional markets, as proposed by FERC in their recent Notice of Proposed Rulemaking on Standard Market Design (SMD NOPR). Another mechanism for ensuring stability is the implementation of RTOs or ITPs. Finally, the Subcommittee proposes that the establishment of long-term resource adequacy obligation could also ensure adequate generation supply and provide certainty necessary to further encourage infrastructure investment.

*Introduction—Ensuring Reliability Over Time*

Ensuring that there are sufficient resources to reliably meet customer demand for electricity at reasonable prices is a critical policy objective. There is a strong expectation on the part of customers that electric service should be reliable, even under extreme conditions of weather and demand. Extended interruptions of electric service can cause serious health and safety risks and can create significant economic impacts on consumers and businesses. Meeting these expectations both today and in the future requires sound policy that encourages participation and reduces uncertainties in the market place.

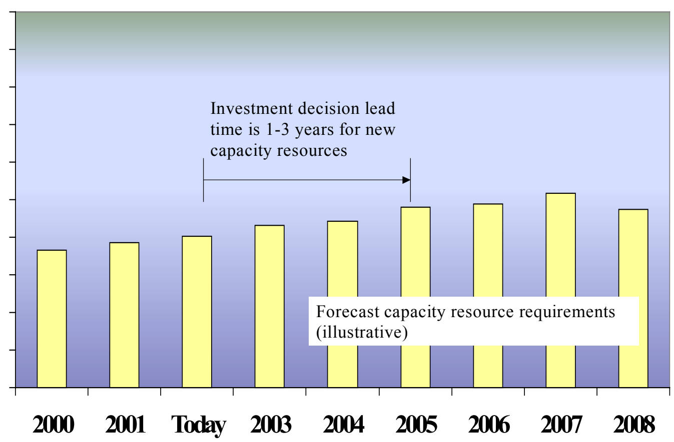


Figure 3: Forecast Capacity Resource Requirements

Ensuring adequate resources are available over time requires that ongoing investments be made in new resources and technologies, including demand-side alternatives, not only to meet annual growth in customer demand, but also to replace generation that is aging and becoming very costly to maintain and run. As shown in Figure 1, an important consideration is the lead-time required to make these investments. Given current technologies, decisions to build new generation or install new demand-side management systems typically have to be made anywhere from one to three years in advance. Companies must plan the investment, secure financing, and obtain any necessary regulatory approvals before the resource[17] is available to meet the needs of the market place. This lag time is unavoidable.

More importantly, it means that mechanisms must be put in place to provide the investment signals well in advance of when the new resource is actually needed. By providing information on the long-term requirements, customers and industry can make informed decisions of when and how much new investment is required. It allows different technologies, including both supply and demand, to compete to serve these requirements, which will ultimately deliver more efficient results to customers.

*Impacts of Adequate Supply on Market Efficiencies*

In addition to the reliability aspects, FERC has stated that there must be adequate generation supply in order for wholesale electricity markets to function properly. FERC has also recognized that the current electricity markets have very inflexible demand characteristics and that, at present, demand is generally insensitive to short term prices. The SMD NOPR seeks to standardize transmission service and energy pricing mechanisms for wholesale energy transactions. The SMD NOPR also includes a provision for long-term supply adequacy.

### *A. Standard Market Design*

FERC's SMD NOPR proposes mandatory rules to standardize the U.S. electricity markets in order to allow electricity transactions to occur across geographic boundaries. The proposed rule provides for stability, reliability and growth in the wholesale electricity market by emphasizing physical generation and transmission asset development; common market design and independent market operation; new investment in generation, transmission, and distribution; and encouraging infrastructure development through bilateral contracts. While the Subcommittee is not prepared to comment on the entire SMD NOPR at this time, it does, however, support FERC in its efforts to put in place common rules and pricing mechanisms that should help prevent a repeat of the power crisis endured by Californians during 2000-2001.

The Subcommittee encourages the reader to consider the EAB's Subcommittee on Transmission Grid Solutions Draft Report for a more in-depth discussion and recommendations concerning pricing mechanisms.

[17] Throughout this Draft Report, the term capacity resource is used to refer to both generation supply resources and curtailable demand resources to recognize the fact that either type of resource can be used to meet future load growth requirements.

*B. Implementation of Regional Transmission Organizations or Independent Transmission Providers*

The DOE's National Transmission Grid Study cites the challenges of uniting the generation and transmission planning perspectives to support wholesale markets. FERC's SMD NOPR proposed the establishment of Regional Planning Councils and Regional State Advisory Committees to provide for coordinated resource and long-term planning of infrastructure based on need. The EAB Subcommittee on Transmission Grid Solutions undertook a detailed examination of these issues in its review of the Grid Study. In its Draft Report, the Transmission Grid Solutions Subcommittee highlighted the importance of forming RTOs to facilitate grid-expansion and to improve the operation of competitive wholesale electricity markets. Some benefits of RTOs include:

- Improved market performance
- Elimination of duplicative charges
- Elimination of artificial seams
- Standards that are known and consistent

The Subcommittee encourages the growth and development of independent RTOs and ITPs (as described in FERC SMD NOPR) with the belief that they will be instrumental in providing key consumer and market benefits while the market awaits the full benefits of a standard market design. The Subcommittee believes that RTOs/ITPs will:

- Keep the energy flowing across boundaries;
- Reward efficiency and planning in the market;
- Help State Regulators (and FERC) be further empowered to protect consumers;
- Benefit consumers by enabling more cost-effective power to flow across large regional areas;
- Encourage construction of new power plants and transmission facilities; and
- Allow power plants to be turned on and off in a more efficient manner, which translates into a better environment and cleaner air.

*C. Long-term Resource Adequacy*

In addition to the long-term benefits that will be reaped form standardizing the wholesale electricity market and regionalizing the planning processes, the Subcommittee believes that an additional mechanism, if incorporated by FERC, could further add to the stability in the market. The Subcommittee recommends the creation of a long-term resource adequacy obligation, and associated market mechanisms, as another means of ensuring there are sufficient resources available over time to meet customer demand. If properly designed, such an approach can produce significant benefits for both consumers and industry:

- It will provide better information to the market place that will stimulate innovative solutions to meet the market's requirements.
- It will increase the long-term reliability of the electricity supply system.

- It will increase the level of competition in the market place by encouraging entry of both new supply and new demand resources.

Current State of Play

At present, there is no standard mechanism for addressing the long-term resource adequacy on a national level. There is a mix of approaches with enforcement mechanisms that vary widely from none to specific financial penalties. Integrated resource planning processes fall into the implicit category because they generally do not have explicit consequences defined. Most states require load-serving entities (LSEs)[18] to submit an integrated resource plan that identifies their plan for meeting the long-term supply adequacy requirements of their service territory. These plans, however, are generally not specific commitments. They identify future needs and general plans for meeting these needs. Moreover, there are typically no clear consequences specified in advance if the plan fails to meet actual supply requirements or if an LSE fails to implement the plan in a timely manner. Consequences are applied after-the-fact through the regulatory process.

In some regions, however, LSEs must not only demonstrate they have sufficient capacity planned to meet their requirements but they also face specific financial penalties if they do not meet their obligation. Under this approach, LSEs must demonstrate on a regular basis that they have sufficient supply to meet their stated capacity obligation. If an LSE does not have sufficient capacity to meet its obligation, it must either purchase additional capacity or face financial penalties. Mandatory capacity obligations such as this already exist in the three Northeast markets and have been proposed for California and the recently submitted SeTrans Regional Transmission Operator in the Southeast.

[18] The term load-serving entity is used throughout this Draft Report in the broadest sense to include all types of electric utilities serving retail customers, including investor-owned, municipal, cooperative and public power utilities.

## Policy Decision Required

A fundamental question now facing the industry is whether long-term resource decisions should continue to be addressed through the current mix of resource adequacy planning or if a standard approach should be taken. From a policy perspective, the decision that must be made is whether a capacity obligation should be imposed on all entities serving load, and if so whether a single pre-determined design should be applied to all regions of the country. FERC's SMD provides an opportunity to implement an explicit capacity obligation as the common approach for all regions. The Subcommittee notes that the NOPR does not include capacity markets as a separate standard, and in fact proposes to eliminate the installed capacity (ICAP) markets that now exist. However, the Subcommittee believes that inclusion of long-term capacity markets may aid in market certainty.

## Arguments for Long-term Resource Adequacy Obligations

The proponents of resource adequacy obligations argue that such a mechanism is required to assure the long-term reliability of the system. It requires LSEs to take a long-term view of their capacity requirements. Knowing that the capacity obligation is in place provides incentives necessary for LSEs to invest in new supply, and more importantly, it will do so in a timely manner. As a result, sufficient supply will be available and prices should be less volatile. Without such an obligation, the proponents argue that it is more likely that the industry will experience longer periods of potential supply deficiencies due to the lag time between market signals and investment decisions. The result would be longer periods of higher energy prices and volatility.

## Arguments for Not Having Long-term Resource Adequacy Obligations

The opponents of having a resource adequacy obligation argue that investment decisions should be driven by the energy price signals produced by the competitive energy market and that current regulatory planning processes are sufficient. The energy market would operate efficiently and provide prices that signal demand and supply to respond accordingly to supply deficiencies and excesses. The laws of supply and demand would dictate. During periods of sustained supply shortages, the energy market prices would be expected to be high providing the incentives for companies to bring on new supply. Similarly, this rise in energy prices would also provide sufficient justification for regulators to approve investments in new facilities.

For this approach to work, however, prices must be permitted to rise over time, and in some instances to rise to very high levels for those periods when demand is high and supply margins are low. However, the current electricity market does not have the same degree of buyer responsiveness typically found in most commodity markets.[19] Given this lack of demand-side response in current energy markets, the current regulatory and customer environment has not been prepared to accept these high price levels. In many instances, the response has been to impose price caps on these short-term markets, which are the very markets that are supposed to provide the price signals for the long-term investments.

## Mandating Long-term Resource Adequacy Obligations

Ensuring that the market receives proper price signals in a timely manner is critical to meeting the long-term adequacy policy objectives. As shown in Figure 3, the market price signals that exist today will drive the investment decisions necessary to meet new requirements for the next several years. If these signals are muted due to price caps or other regulatory interventions, it may cause these decisions to be delayed or not made at all. The result is that the long-term reliability and efficiency of the electricity system may be unnecessarily threatened. It is recommended that a resource adequacy obligation mechanism be designed to assure the long-term reliability of the system. Such an obligation requires LSEs to take a long-term view of their capacity requirements.

There are two basic implications of this recommendation:

1. A capacity obligation mandates that all LSEs, or the market collectively, forward contract for a certain quantity of the defined capacity product.
2. Failure to meet this mandated obligation results in some form of financial consequence.

For instance, an LSE transmission customer serving 1000 MW of load in the region would be required to demonstrate, presumably to an RTO, that it had sufficient capacity resources to cover its obligation for the upcoming planning period (*e.g.*, month, season, year). The LSE would have to make this demonstration in advance of the period. It can meet its obligations with generation and demand-side resources it owns or purchases from other capacity resource providers in the market place. Similarly, it could purchase capacity resources in a coordinated market to the extent such a market was available. If the LSE fails to demonstrate that it has met its obligation, it could either be required to purchase the difference in some form of auction, or it would be assessed some form of financial penalty, which could be used to procure capacity.

## FERC's Resource Adequacy Proposal

In its SMD NOPR, FERC included a long-term resource adequacy proposal with the following features:

[19] Generally, buyers will tend to buy less as prices rise. While progress is being made to encourage more demand side response in the electricity industry, it is generally agreed that the current level of demand side response in electricity markets is far less than that seen in other commodity markets.

- The regional adequacy requirement and planning horizon would be set through a coordination committee known as the Regional State Advisory Committee.
- All LSEs would have to demonstrate their plans to meet their allocated share of the regional requirement by the end of the planning horizon.
- LSEs may use both supply and demand resources to meet their obligations. They may also use resources they have contracted to purchase bilaterally as credit towards their obligation.
- If an LSE submits a plan showing it does not have sufficient resources by the end of the planning horizon, it is put on notice that it will face financial penalties if it does not cure the inadequacy before that time. Thus, the financial penalties are not imposed today for a future obligation. Rather, they would only be charged to the extent that the LSE fails to invest in sufficient capacity resources.

### Coordination with Existing Planning Requirements

State mandated resource planning plays an important role today in setting specific reliability needs for each area of the country. This role should continue. These existing processes are not mutually exclusive with a resource adequacy obligation and, as endorsed below, should be a necessary input as recently proposed by FERC in its SMD NOPR.

### Principles for Creating a Resource Adequacy Obligation and Market Mechanisms

Capacity obligations and associated market mechanisms are currently in place in the three Northeastern markets and are under consideration in many other jurisdictions. As these regions have gained experience, the RTOs in these regions have recognized that improvements must be made to their existing designs. As a result of these efforts and FERC's recent proposal, certain fundamental design principles have become clear and should be endorsed:

### Forward Capacity Obligations on Load Serving Entities

An LSE must know how much capacity it is required to procure and over what time period well in advance. Current proposals have this obligation set at least months in advance and possibly years in advance. An LSE would be able to self-supply resources[20] to meet its obligation or it could purchase capacity from an organized auction to the extent available.

### Clearly Defined Obligations on Resource Providers

Clearly defined performance requirements must be defined for capacity resource providers. Technical standards must be met by which to measure the performance of all providers. Any capacity resource, supply or demand, meeting these requirements qualifies as an eligible capacity provider. In return for

[20] Self-supply would include both resources owned by the LSE and purchased bilaterally from qualified providers.

being compensated for its capability, providers must agree to undertake certain obligations aimed at protecting system reliability and consumer interests. Mandatory bidding requirements and voluntary price caps are two examples of obligations imposed on generators participating in capacity markets in the Northeast.

Explicit Enforcement Mechanisms and Penalties

For the obligations to have "teeth," all parties must know what the consequences are of not fulfilling those obligations. LSEs should face some form of financial consequence or penalty for not meeting their obligation. This penalty needs to be high enough so that fulfilling its obligation is more attractive than incurring the consequence. Likewise, it is reasonable to make capacity providers subject to financial consequences for not meeting their obligations with the same rationale.

Coordination with State Mandated Requirements

The mandatory capacity obligation should be designed so that it compliments and does not conflict with existing State mandated integrated resource planning requirements. State regulators play an important role in setting regional specific reliability requirements to serve the needs of the customers in their jurisdictions. The design of any mandatory capacity obligation must take these requirements into account. FERC's recent proposal recognizes this requirement by defining the role of the States in the Regional State Advisory Committee provisions.

Demand-Side Participation

The capacity market should be designed to facilitate participation by demand-side resources. Rules should be set so that demand-side resources are treated on a non-discriminatory basis.

Market Monitoring

Some of the capacity market features described above are directly aimed at reducing anti-competitive and gaming behavior in the market. Larger RTO markets, longer lead times for obligations, centralized markets and increased opportunities for demand-side participation are all measures being taken to improve the competitiveness of these markets. However, it is impossible to guarantee that an abuse will not occur. Standards for market monitoring and mitigation should be clear, openly communicated to market participants, and prospective only.

## Summary

Customers expect electric service to be both reliable and delivered at reasonable prices. Ensuring that there are enough resources to reliably meet customer demand is a critical policy objective. In an effort to facilitate this policy objective, FERC is pursuing the development of RTOs and the SMD NOPR, which includes a long-term resource adequacy requirement. Implementing a resource adequacy obligation as proposed in this Draft Report is consistent with these efforts and provides the following advantages:

- It will provide strong forward price signals so that new investments can be made in a timely manner.
- It will provide LSEs with sufficient choices and time to meet their obligations.
- It will allow capacity providers to undertake certain obligations for providing this service.
- It recognizes the reality that extremely high energy market prices and extreme price volatility are not acceptable in today's environment.

## VII. Standards of Conduct and Corporate Practices for Energy Providers

The crisis in confidence in the corporate practices of some energy companies is one factor that has driven capital away from necessary investments in energy infrastructure. This tremendous upheaval will not be calmed until investigations conclude, consequences are determined and expectations about future corporate practices are communicated.

Multiple federal agencies, such as the Federal Energy Regulatory Commission (FERC), Securities and Exchange Commission (SEC), the Commodities Futures Trading Commission (CFTC), and the Department of Justice (DOJ) are conducting investigations on a broad array of issues. In addition to the Federal investigations, several state Attorneys General, legislatures and utility commissions are also conducting their own individual investigations. It is essential that these investigations are coordinated and expedited so that we reach closure as quickly as possible.

There are also significant efforts underway by energy industry stakeholder groups such as the Electric Power Supply Association (EPSA); the Edison Electric Institute (EEI); National Energy Marketers' Association (NEMA); the Western Power Traders; and the Committee of Chief Risk Officers (CCRO), to develop a code of conduct or shared principles for corporate practices.

The EAB is in the process of forming a separate subcommittee to address the issue of corporate governance and practices. That subcommittee will conduct a careful review of these multiple proposals and offer a consolidated plan that defines best in class corporate practices.

***Remedies:***

a) A clear delineation of responsibilities, specifically focused on capital market and investor issues, between FERC, SEC and CFTC will reaffirm ownership and provide clarity on key issues. Appointed agency liaisons may help to provide the needed coordination. This delineation may be included in the Electricity Restructuring currently under review by Congress for passage in 2002.
b) The role of an organization such as the National Futures Association should be considered.
c) A nationally recognized accreditation of corporate practices endorsed by the SEC and FASB that provides appropriate consequences is needed to reassure the public that change has occurred and energy companies are adhering to these standards.

## VIII. Summary

The benefits associated with the continued realization of competitive wholesale markets argue strongly for a re-invigoration of investment into energy infrastructure. The security, reliability and low-cost demanded by customers from an energy market can be delivered by providing the investment community with regulatory certainty and by standardizing markets and pricing policies.

The benefits of competitive wholesale markets include lower long-term prices, improved reliability, innovations in technology, and properly allocated risks, e.g., away from consumers and to investors. However, in order for end use customers to reap these benefits, the investment community requires certainty that the restructuring of the market will proceed on a predictable pace and within a defined scope. There needs to be sanctity of contracts so that there is no risk of abrogation of binding contracts entered into by two parties. And finally, there needs to be a greater degree of predictability about future regulatory requirements such that the industry is not subjected to a patchwork of environmental requirements that hamper long-term planning decisions.

The Subcommittee supports the implementation of a Standard Market Design and the formation of Regional Transmission Organizations to provide the needed uniformity in the market place. With the addition of long-term capacity markets, the Subcommittee believes that national resource adequacy needs can be met. The Subcommittee supports the ongoing efforts of FERC to implement these initiatives and believes they will provide the solutions necessary to secure investment in electricity generation and delivery.

Finally, the Subcommittee recognizes that there are serious concerns in the investment community with regards to the integrity of corporate practices. The Subcommittee supports the formation of a new EAB Subcommittee on Corporate Governance to review and comment on the ongoing efforts by various entities to develop standards of conduct and acceptable business practices. In addition, the Subcommittee believes that a clarification of roles and responsibilities between FERC, the Securities and Exchange Commission and the Commodities Futures Trading Commission will reaffirm ownership and provide the necessary clarity of key issues.