

**THE FEDERALIZATION OF ENERGY PRICES:
HOW POLICIES ADOPTED BY THE FEDERAL ENERGY
REGULATORY COMMISSION IMPACT ELECTRICITY PRICES
FOR RESIDENTIAL CUSTOMERS**

A PLAIN LANGUAGE PRIMER

Barbara Alexander
Consumer Affairs Consultant
83 Wedgewood Dr.
Winthrop, ME 04364
E-mail: barbalex@ctel.net

March 2008

Barbara R. Alexander opened her own consulting practice in March 1996. From 1986-1996 she was the Director, Consumer Assistance Division, at the Maine Public Utilities Commission. Her special area of expertise has been the exploration of and recommendations for consumer protection, universal service programs, service quality, and consumer education policies to accompany the move to electric, natural gas, and telephone competition. She has authored "A Blueprint for Consumer Protection Issues in Retail Electric Competition"(Office of Energy Efficiency and Renewable Energy, U.S. Department of Energy, October, 1998). In addition, she has published reports that address price volatility and consumer benefits associated with the provision of basic electric and natural gas service: "Managing Default Service to Provide Consumer Benefits in Restructured States: Avoiding Short Term Price Volatility" (2003), available at http://www.neap.ncat.org_experts_index, and "Natural Gas Price Volatility: Regulatory Policies to Assure Affordable and Stable Gas Supply Prices for Residential Customers," (2004), available at <http://www.ncat.org/liheap/news/Feb04/gaspricevol.htm>. Most recently, Ms. Alexander has published an analysis of "red flag" issues associated with state consumer protection regulations, "Red Flags for Consumer Protection Policies Governing Essential Electric and Gas Utility Services: How to Avoid Adverse Impacts on Low Income Consumers" (October 2005), which is available at: <http://www.liheap.ncat.org/pubs/balexanderconsstudy05.doc> and an analysis of the potential impacts of "smart meter" and time-based pricing policies on low-income electricity customers, available at: http://www.pulp.tc/Smart_Meter_Paper_B_Alexander_May_30_2007.pdf. Her clients include national consumer organizations, state public utility commissions, and state public advocates.

This report was prepared under contract with
Oak Ridge National Laboratory UT-Battelle, LLC
Purchase Order No. 4000049807

The opinions and conclusions expressed in this report are
those of the author alone and do not necessarily represent
the views of Oak Ridge National Laboratory or the
U.S. Department of Energy

TABLE OF CONTENTS

I. INTRODUCTION AND EXECUTIVE SUMMARY

The purpose of this paper is to explore and explain the growing influence of federal policies as developed and implemented by the Federal Energy Regulatory Commission (FERC) on retail electricity prices. While a good deal of the overall approach by FERC as described in this report are applicable to retail natural gas prices, the emphasis in this analysis is on retail electricity prices because of the more controversial implementation of retail electricity restructuring and recent and dramatic price increases in those states that have ordered their utilities to purchase generation supply in the wholesale electricity market. Once restructuring took hold in many states, the price for generation supply service could no longer be established by reviewing and approving the actual costs to build and operate generation facilities because the local utilities were ordered to either sell or transfer such assets to structurally separate affiliates. As a result, the “rules of the road” with respect to pricing generation supply service in the wholesale market took on new meaning and significantly more importance for retail customers. FERC was left with the task of creating or stimulating the creation of wholesale market structures to govern how electricity would be bought and sold, a task that was not contemplated by the federal statutory legislation then in effect. This paper examines how FERC developed and implemented policies and programs to govern its new found and expanded jurisdiction over the bulk transmission system and the sale of generation supply in the wholesale market.

FERC’s policies have a particularly direct impact on retail prices in states that have adopted and are implementing retail competition or restructuring. By 2000, over 20 states had adopted electric restructuring, but several repealed or halted its implementation of retail restructuring after the California market meltdown in 2001-2002. Nevada repealed restructuring

and allows only the largest customers to shop for electricity. New Mexico and Arizona halted their implementation of restructuring. More recently, Virginia and Montana have repealed retail restructuring in 2007. While California has not repealed restructuring, there is no current mechanism in place to implement retail competition for residential customers. The following states have actually implemented retail restructuring and theoretically allow for retail competition or customer choice for all customer classes; Maine, New Hampshire, Massachusetts, Rhode Island, Connecticut, New York, Pennsylvania, Delaware, New Jersey, Maryland, District of Columbia, Illinois, Michigan, Ohio, and Texas.¹ The typical market model adopted by these states was to require or incent the local utilities to sell their generation assets or transfer these assets to an affiliate. As a result the state regulatory commission was left with jurisdiction over the “distribution” utility, an entity that provides distribution services to retail customers, but who must purchase generation supply from wholesale market suppliers. The theory of this approach was that the competitive wholesale market would result in more efficiencies in the operation of generating plants, stimulate investment in lower cost generation, transfer the risk of investment from customers to shareholders of existing and future generation suppliers, result in more innovation, and lower prices compared to traditional cost of service regulation of generation supply provided by vertically integrated utilities.

It is not clear that state policymakers understood the implications of losing jurisdiction over local utility generation supply assets, particularly since the actual creation of the regional wholesale markets and FERC’s policies to supervise and regulate these markets were not yet adopted or implemented.² In other words, most states that adopted restructuring in 1997-2000 and allowed the transfer of generation supply assets to a wholesale market that had not yet been

created or implemented. These states, intentionally or not, transferred substantial authority for electric system planning, power, energy, and transmission regulation, and pricing to the federal government and FERC.

In addition to the state vision of restructuring's impact on future generation supply prices and the operation of the wholesale market, states also assumed that restructuring would result in retail competition, that is, the sale of electricity to end-use customers. While the retail sale of electricity remained subject to state control for the purposes of licensing and consumer protection policies, states assumed that the forces of competition would drive down the price of electricity and result in more innovative products and services. States ordered utilities to "unbundle" the bill so that the distribution or regulated function would be separately stated from the generation supply or unregulated portion. States were promised by many national promoters of restructuring, particularly Enron who sent lobbyists and representatives to every state contemplating restructuring, that new marketers would come in and seek to serve all customer classes, offering generation supply in competition with utilities and that many new products and innovations would result. States adopted licensing regulations for newly emerging retail marketers and ordered utilities to undertake expensive electronic data exchange protocols with licensed marketers so that they could offer services that would appear on the utility bill or that would allow these marketers to bill customers directly for electric service. State regulators ordered utilities to spend ratepayer funds on statewide education campaigns with television, radio, and newspaper advertisements and stories, customer brochures, and websites to educate customers on how to shop for electricity. In the early days of implementation of restructuring, there was in fact a good deal of marketer interest and marketing to residential customers in some

states, with up to 20% of residential customers migrating to competitive electricity suppliers in several Pennsylvania distribution service areas by early 2000. However, this marked the watershed high of residential customer choice activity in most states.

In the early days of the implementation of restructuring, utilities were typically required to continue to serve all customers with a “default” or “standard offer” service.³ This meant that all customers continued to receive generation supply service from their incumbent utility at the onset of restructuring.⁴ The price for this service was typically “frozen” or “regulated” for a transition period, at the end of which it was assumed that most customers would already have service from competitive suppliers and that the future purpose of Default Service would be to serve as a temporary haven for those customers in between suppliers or who could not obtain service from competitive suppliers. At the end of the rate cap or rate freeze, most state restructuring legislation required state regulators to order utilities to obtain generation supply for Default Service from the wholesale market. While residential customers in most restructuring states were shielded from any wholesale market price changes during a rate cap or rate freeze period, those caps have expired in most states. States in which Default Service prices reflect the pass through of generation supply purchased in the wholesale market include: Maine, Massachusetts, New Hampshire, Connecticut, Rhode Island, New York, Delaware, Maryland, New Jersey, Illinois, and the District of Columbia. While some of Pennsylvania’s electric utility rate caps have expired, the bulk of the state’s residential customers remain under rate caps that will expire in 2010 or 2011. Ohio’s rate caps or “transition” rates will begin to expire by the end of 2009. Michigan’s restructuring law is unique in that the utilities are required to continue to

provide Default Service under traditional cost of service ratemaking and the utilities were not required to transfer generation assets.

Whatever the original vision, the fact is that a robust market for the sale of generation supply service to residential and small commercial customers has not developed in almost any state. There are several reasons for the failure of the retail market for residential customers to develop and this paper does not address this issue.⁵ However, for our purpose here the key point is that almost all residential and small commercial customers continue to receive Default Service from their incumbent utility even after the expiration of rate caps and the pass through of wholesale market prices for Default Service to these customers. Therefore, the vision that retail competition would result in lower prices and innovative services has simply not come to fruition for residential customers. As a result, how Default Service is obtained and priced has assumed a more significant role than original anticipated.

FERC's role in its supervision and regulation of the wholesale electricity market has come under criticism recently in a variety of studies that have alleged that retail prices for electricity have risen higher in restructuring states compared to retail electricity prices paid by customers in states that have not adopted retail electric competition or restructuring. These studies claim that prices have risen higher in restructuring states due in part to the structure and operation of the regional wholesale market organizations, the ability of wholesale generators to exercise market power and obtain higher prices, and that such price increases cannot be explained only by increasing fuel costs. According to one author, competitive markets in general should lead to efficiency and innovation, "But tightly centralized, administered markets do not fare well by these standards. In fact, in the past decade prices have increased more rapidly in the

administered markets even when corrected for fuel costs. The exercise of market power is common and there is little or no evidence of efficiency improvements.’⁶ This paper does not attempt to determine if these observations or criticisms are valid. Rather, the purpose of this paper is to explain in layman’s terms what policies FERC has in fact adopted and how the growing influence of regional wholesale market structures has impacted and will continue to impact retail electricity prices in restructuring states. It is likely that these policies will gradually have similar impacts in states that have not adopted restructuring, particularly where local utilities must interact with regional wholesale markets as either buyers or sellers on behalf of their retail customers.

The paper begins with a short history of FERC’s jurisdiction and federal energy policy legislation. It then covers the following topics:

- FERC’s policies and actions to stimulate and oversee the wholesale market for the transmission of and sale of electricity.
- The growth of regional transmission markets.
- The role of regional transmission markets in setting marginal or “day-ahead” prices for wholesale electricity and how that market has influenced retail electricity prices in states that have adopted retail competition or restructuring.
- FERC’s role with respect to the development of planning and development for new capacity, as well as FERC’s policy preferences to stimulate advanced metering, the “smart” grid, and demand response programs that emphasize the benefits of time-based pricing.

FERC’s policies and the operation of the current structure of the wholesale market for the sale of electricity, coupled with state adoption of restructuring, have resulted in the following observations and trends:

- There has been a clear and dramatic loss of state control over prices charged by generation facilities for electricity because these generation supply units are no longer “owned” by the local public utility. As a result, the power sold by the generators is no longer based on actual costs, but are based, at least in part, the complex pricing methods administered by the regional wholesale market. The publicly available price information in these markets is focused primarily on “day-ahead” markets and are designed to charge higher prices in areas with transmission constraints. In addition, the pricing methods reflect a “bid stack” method of setting prices in which the highest bidder sets the price for all generation needed to serve load in a particular hour or time of day. The older generation units that were paid for by local ratepayers are sometimes able to obtain a much higher price for their output than under traditional regulation.
- When states adopted restructuring, the statutory directive was typically to ensure that the future price of electricity sold to consumers would reflect a competitive market price because state policymakers assumed that the introduction of competition would result in lower prices compared to traditional regulation and that new generation would be built and offered for sale to retail customers at prices lower than the expensive nuclear power and other facilities that contributed to the move to restructuring in the first place. Therefore, the restructuring statutes typically directed state regulators to order their utilities to obtain generation supply obtained through competitive means in the wholesale market to provide service to retail customers and expected that new retail competitive energy suppliers would compete to provide the lowest cost service to all customers. However, there is little or no interest in serving residential customers in most states. Most state Default Service policies have emphasized relatively short term (1 to 3 years) contracts in which the successful bidder provides all the necessary energy, balances the supply and demand, and otherwise assume responsibility for assuring that the electricity flows to the utility’s customers, typically referred to as “full requirements contracts,” under a fixed price for the term of the contract. The prices for these contracts have reflected the regional wholesale market structure and pricing policies administered by regional organizations. As a result, retail prices reflect market volatility, the rise in

natural gas prices, and the emphasis on short term market trends. Default service prices are no longer a reflection of a diverse portfolio of generation supply units and price structures that were based on long term investment under traditional regulation.

- State energy prices for Default Supply obtained in this manner have reflected a total reliance on generation supply and have destroyed the link between generation supply and energy efficiency and demand response analysis and resources that was mandated under long term integrated resource planning in traditional cost of service regulation. While some states adopted “surcharges” and “public benefit charges” to continue some level of investment in energy efficiency and renewable resources, the level of funding that such initiatives supported reflected a dramatic drop in investment in these resources compared to previous regulatory policies in many states. It is only recently that the states have realized this significant defect and turned to the stimulation of energy efficiency programs to incorporate the potential for “negawatts” in the pricing of electricity and the control of long term demand. FERC also has realized this defect in its current market structures and has now favored the ability of demand response resources in particular to be bid into longer term capacity market auctions operated by the RTOs.
- When the utilities divested their generation supply resources, most states also assumed that the “market” would cause the necessary level of investment in new generation to assure long term reliability of supply and result in lower prices compared to the traditional method of long term utility planning and investment with regulated rates. While there has certainly been some level of new investment, particularly in the early days of restructuring when new natural gas fired generation facilities were constructed, many of the suppliers declared bankruptcy or halted development plans after the California market meltdown resulted in a dramatic drop in investment capital.⁷ As a result, there is a general consensus that regional markets needed to adopt a more “regulated” or “administered” approach to attempt to stimulate investment in new generation. RTOs and other regional organizations under FERC control have taken over the role of long term planning and assurance of reliability of service and developed highly

controversial new regional capacity markets that are designed to significantly increase electricity prices in areas that need new investment in generation.

- Finally, FERC's policies and the structure of the regional electricity markets have relied on spot markets and hourly prices to send the signal about the need for and cost associated to provide new generation facilities, as well as the need to encourage the development of demand response programs as a substitute for new generation. This approach to assuring long term reliability of supply and new investment in generation has contributed to more emphasis on volatile pricing methods. This approach has the potential to result in the growth of time-based pricing regimes in which retail customers "see" real-time or day-ahead wholesale market spot prices so that they are stimulated to lower usage during certain times of the day or certain peak usage hours when the price for electricity is higher than normal. Federal statutory policies and FERC's support for creating the Smart Grid and utility investment in Advanced Metering are justified in part on the need to reform retail pricing for electricity to move toward time-based and "real time" pricing to reduce peak demand.

The overall conclusion of this analysis is that FERC's policies with respect to the structure and function of the regional markets, the manner in which electricity is priced in the regional markets, the emphasis on short-term price signals, the increased complexity of regional market structures and regulations, and the design and implementation of newly formed capacity markets reflect an attempt to design a new federally controlled structure for a changed electric industry. FERC's policies and programs to stimulate and establish "competitive" wholesale markets and the influence of those markets on retail prices are a function of specific regulations and approaches adopted by FERC and not the result of the operation of the competitive market acting alone. The implications of these affirmative choices by FERC have certainly not been

considered or finally adopted with any significant input from those most affected by these decisions—residential end-use customers. Unlike most state regulatory agencies, FERC does not have the benefit of any institutional advocate for end-use customers, nor do FERC-supervised regional authorities necessarily have such advocates.

Second, the implications of FERC's policies for retail prices are growing even though the concerns about the structure and operation of retail competition at the state level have resulted in statutory reform of state restructuring policies and, with respect to Montana and Virginia, a repeal of retail competition and a return to traditional cost-based regulation of electric utilities. In jurisdictions in which the distribution electric utility sold or transferred its generation supply assets, the state regulatory commission has lost its formal jurisdictional authority over those generation assets. The owners of those assets are now subject to FERC's jurisdiction and the regional market operators. As a result, state policymakers who seek to gain more control over electricity prices must consider options that will decrease the reliance on short-term wholesale market prices as the basis for retail electricity prices. This conclusion explains increasing state interest in longer term procurement planning for generation supply, renewed interest in long term contracts to assure reliability of service, consideration of significant increased funding for energy efficiency programs, as well as interest in demand response programs that will reduce usage at certain peak load hours or days, the most expensive component of electricity prices in regional markets.

Finally, it is fair to also identify the role that state policies and state regulators have had with respect to this growing federalization of retail electricity prices. While this paper does not address the potential state reforms that may be considered in response to this growing

federalization of retail electricity prices, there are a number of recently issued state-level reports that highlight these options and others. The Bibliography attached to this report includes information on Default Service policy reforms enacted or under consideration in several states.

II. A BRIEF HISTORY OF FEDERAL JURISDICTION OVER ELECTRICITY AND NATURAL GAS PRICES

The Federal Energy Regulatory Commission (FERC) is a fairly modern federal agency, but its precursor is one of the first federal regulatory agencies whose mission was expanded with the New Deal reforms adopted in the 1930's in the wake of the economic collapse in the Great Depression. During President Franklin Roosevelt's first term in office, Congress enacted the Securities Act of 1933, the Securities Exchange Act of 1934, the Public Utility Holding Company Act of 1935 (PUHCA), the Federal Power Act of 1935 and the Natural Gas Act of 1938. These laws formed the basis for the regulation of electricity and natural gas utilities until the enactment of the Public Utility Regulatory Policy Act in 1978 (PURPA), the Natural Gas Policy Act of 1978, the Energy Policy Act of 1992, the Energy Policy Act of 2005, and the recently enacted Energy Independence and Security Act of 2007. During the 1930's states also adopted reforms to their regulation of electricity and natural gas and most states formed independent regulatory agencies modeled on the federal approach to provide oversight and rate regulation of public utilities.

The Federal Power Commission (FPC), the predecessor of FERC, was created in 1920 and was originally focused on non-federal hydropower development and regulation to assure the operation and safety of dams built to generate electricity. With the advent of the reform legislation adopted in the 1930's, the FPC took on regulation of electricity to ensure that the rates, terms, and conditions of the resale of electric energy and transmission in interstate commerce by public utilities were "just, reasonable, and not unduly discriminatory or preferential."⁸ It should be noted that the vast bulk of generating facilities during this period

were in fact regulated by the states and that the federal jurisdiction impacted a relatively minor portion of generation supply sales or customer rates. The same approach or mission was enacted for the FPC's regulation of interstate natural gas sales.⁹ The FPC was abolished with the creation of FERC in a government reorganization approved by Congress in 1977. FERC inherited most of the Federal Power Commission's mission and authority.

FERC is composed of five members appointed by the President and approved with the advice and consent of the U. S. Senate. The Commissioners have five-year staggered terms and no more than three members may be from the same political party. One member is designated by the President as Chair and serves as the administrative head of the agency.

As a result of the reform legislation adopted in the 1930's, the FPC undertook to supervise interstate transactions to assure that rates, terms, and conditions were "reasonable." FPC's jurisdiction was limited to interstate or utility-to-utility transactions that made use of interstate pipelines or transmission facilities. The Federal Power Act required that access to the interstate facilities (pipelines and transmission lines for electricity) be available in a nondiscriminatory manner and that sales prices reflect actual and reasonable costs with a reasonable rate of return. Natural gas pipelines bought natural gas and sold it in turn to their utility and industrial customers as regulated monopolists at federally regulated rates. Electric utilities generated and purchased electricity and sold it in like manner as monopolists to both retail customers and wholesale customers like municipal utilities within their service territories. Only the wholesale transactions were federally regulated.

Rates were required to be filed with the FPC and publicly available in tariffs. During this period, the type of regulatory approach used by the FPA was similar to that in use by the States to

regulate the retail sales of electricity and natural gas to end-use customers. In both state and federal law, the regulatory mandate was to assure “just and reasonable” rates that were non-discriminatory, which was interpreted as rates sufficient to cover reasonable costs and to provide an opportunity for the public utility to earn a reasonable rate of return or profit. In both federal and in most state laws, the focus was on investor-owned “public utilities” defined in law to exclude publicly-owned utilities, rural electric cooperatives, or other federally-owned facilities or authorities, such as the Tennessee Valley Authority or the Bonneville Power Authority in the Northwest.

From the period of the late 1930’s until the 1970’s, both state and federal agencies operated with similar statutory directives and public policies. Beginning in the 1970’s this approach to state and federal regulation of energy utilities and energy prices began to change. The national and international developments that led to these changes included:

- An apparent end of the “economies of scale” to build and pay for large generating facilities, particularly with the huge cost overruns of large nuclear power plants, leading many observers to conclude that there was no natural monopoly for the generation of natural gas or electricity;
- The Arab Oil Embargo and resulting high energy prices in the 1970’s led to calls for more energy conservation and lowered dependence on the importation of oil from foreign countries;
- A general pendulum swing against “regulation” and the deregulation of the airline and trucking industries under President Jimmy Carter in the 1980’s; and

- The growth of the environmental movement and concern about air and water pollution from large generating facilities, interest in “green” power, local power, decentralized decision making, opposition to the siting of large-scale energy facilities by local citizens, and a promotion of energy conservation as a means to control the growth of energy usage.

As a result of these developments, the FPC (and then FERC after the agency was renamed in 1977) began to dismantle the traditional cost-based regulation of the electricity and natural gas industries when Congress adopted the Public Utilities Regulatory Policy Act of 1978¹⁰ (PURPA) and the Natural Gas Policy Act in 1978.¹¹ The purpose of these changes at the federal level was to enable ‘market prices’ for natural gas to create greater production incentives for that fuel and for high-efficiency cogeneration and renewable energy generating facilities to find a market for their electricity sales.

The Natural Gas Policy Act took FERC out of the business of regulating prices for gas sold at the wellhead (at the point of production) and pointed the way to the adoption of deregulation of wholesale natural gas prices generally which was accomplished in the 1980’s. The regulation of natural gas today is basically a function of treating the interstate natural gas pipelines and their owners as transporters rather than as merchants of gas. FERC accomplished this initiative by requiring that the basic natural gas functions or services be “unbundled” so that the sale itself was treated differently from the transportation function. While the transportation function remains fully regulated, FERC has allowed the sale of natural gas in the wholesale market to be “deregulated”, that is, the price is set by the buyer and seller without specific price approval from FERC. The transition to this system was complicated by the traditional natural gas contracts that had bundled the transportation and sale of the commodity in a “take or pay” contract feature

between the pipelines and the natural gas producers. These contractual disputes were resolved by FERC through litigation without any serious consequences. The result led many observers to believe that the same approach could be accomplished with the sale of electricity.

The adoption of PURPA in 1978 set in motion the seeds of “unbundling” and “deregulation” of the electric industry. Under PURPA, electric utilities were required to buy power from independent or non-utility generators (“Qualifying Facilities” or QFs) at a price that was subject to federal review for wholesale transactions and state review for retail transactions. Many of these QFs were industrial facilities that used energy for some kind of industrial process as well as for the generation of electricity and were therefore considered more efficient in their energy use than power plants that generated only electricity.

Rather than allow the public utility to set the price (and, it was thought, discriminate against independent power producers in favor of their own generating facilities that were earning an authorized rate of return), PURPA required that the utility had to purchase at a price that was set based on the “avoided cost,” defined to refer to the costs that the utility would have to incur to purchase the offered power from a newly built facility owned by the utility. In other words, if the independent generator could offer power for less than the utility could get it from its owned facility, the utility was required to purchase the QF power under contract terms approved by state regulators. To respond to growing environmental concerns, PURPA also required the utility to give a priority to renewable or alternative energy resources and lessen the dependence on oil as a fuel source. This initiative resulted in many new contracts for small or medium sized generating facilities, many of which were powered by municipal or regional trash, biomass, hydropower, and natural gas. In most states, the “avoided cost” was administratively determined after an

analysis of what it would cost the utility to purchase or build its next generation supply unit.

Furthermore, many of these QF contracts were required by state regulators to reflect long term agreements, over 15 years, so that the new competitors could obtain financing for their projects on equal terms with the traditional ratepayer funding of utility investments in new generation.

Even more important to the change in the nature of federal regulation, PURPA gave FERC the authority to order utilities who owned transmission to provide access to the electric grid to these new independent generating facilities so they could sell their power to utilities. In effect, this grant of authority allowed FERC to require utilities to treat the transmission system as a common carrier, similar to FERC's approach to the regulation of natural gas pipelines. Public power utilities had been clamoring for such access to utility-owned transmission to sell their power to utilities or to seek to purchase power from non-utility generators for many years. This statutory authority to FERC was strongly supported by public power advocates at that time for this reason.

Because there was a general consensus that FERC's initiatives in unbundling natural gas prices and relying on market-based forces to set the price for the wholesale transactions had been a success, as well as the growing impetus at that time against regulation of prices in general, Congress enacted the Energy Policy Act of 1992¹² to continue this path toward increased reliance on competition for the electric industry. Key to this discussion was the provision of the 1992 law that allowed FERC to order transmission owners (utilities) to "wheel" or provide transmission service to any generator that requested it, subject to a fee regulated by FERC. The same legislation specifically deferred to state or retail jurisdiction over ordering transmission service owners to furnish power to end users ("retail wheeling"). Another key provision of this Act was

the creation of a new category of federally regulated entity, “exempt wholesale generator” (EWGs) In effect, FERC’s jurisdiction was expanded from “public utilities” to privately owned generators who were made exempt from the size and fuel type restrictions imposed on the PURPA QF generators, many of which were very small and independently owned and operated. EWGs, on the other hand, became major players in the provision of generation supply. They composed a new group of privately owned generators (or owned by utilities in an affiliated relationship) came into existence and sought to sell their power to utilities and, using new developments with natural gas fired generation, were able to offer this power cheaper than traditional large scale generating facilities being built by utilities to serve new customers to meet the growing demand for electricity. However, it is important to understand that the volume of generation supply sales that were subject to FERC’s jurisdiction and the emerging independent power producers at the time of the Energy Policy of 1992 were very small in comparison to the utility-owned generation that formed the bulk of the power sales to retail customers. All of that utility-owned generation was regulated by state commissions under traditional cost of service regulation. The portfolio of generation supply resources used by the local utility to meet its obligations to retail customers was priced based on the average of the total costs of the portfolio so that the cost of the older power plants, particularly the baseload power plants that operated every day to meet the basic load served by the utility, were averaged with the costs of more expensive power needed during peak hours or during times of high load that was seasonal (summer for hotter climates and winter for colder climates).

In 1988 FERC issued Order 888¹³, the beginning of the modern movement toward restructuring the electric power industry. In this Order FERC expanded its approach concerning

access to the transmission system by ordering owners (utilities) of transmission systems to grant access to any generator seeking to transmit power at a price that could be justified as fair and non-discriminatory. FERC based this policy on the Federal Power Act's long standing prohibition on discriminatory prices. FERC stated it would review transmission access prices based on what the utility was charging itself for the use of the system. Second, FERC ordered certain functions to be unbundled, thus taking the same path as it had followed in the unbundling and fostering of market based or competitive prices in the natural gas area. A utility had to provide generation in a manner that insulated it from other utility functions, particularly transmission, so that generation could compete for access to the transmission system and ultimately sales of its electric power on an equal footing with utilities. During this same period, FERC began the process of eliminating the requirement that wholesale market contracts be filed with FERC and specifically approved as "reasonable." Rather, the agency began the process of regulating wholesale market prices by focusing on whether the buyer or seller had market power, presuming that the lack of market power would result in reasonable prices and relying on regional organizations established pursuant to FERC's approval to oversee wholesale market transactions.¹⁴

As a result, some utilities began the process of selling or transferring their generation facilities to affiliates or selling these assets to independent generating companies, at least where state or federal regulators allowed such transfers. This regulatory initiative set in motion and promoted the development of a new set of independent power companies who were not "public utilities" as that term was defined under most state laws, as well as the growth of energy traders who were able to market and trade in electricity products in the wholesale market. The foremost

of these new businesses was Enron Corporation, formed by Kenneth Lay out of the merger of several natural gas pipeline companies in the late 1980's.

The impetus to allow what were perceived to be competitive market forces to also set retail prices and to restructure the electricity industry then moved to the state arena. By 2000, over 20 states had adopted retail electric competition and many more were seriously considering it. However, the California market "implosion" in 2000-2001, the collapse and bankruptcy of Enron, and a growing political nervousness about even some of FERC's initiatives to push for a more structured wholesale market, resulted in a collapse of the rapid movement to restructuring at the state level. In fact, all of the Western states that had adopted or were in the process of adopting restructuring halted or repealed that movement, including Arizona, New Mexico, and Nevada. Even though California demonstrated that restructuring the electric power industry could go terribly wrong, many of the Midwestern and Eastern States pursued the restructuring path, although no state adopted restructuring after 2000.

The Energy Policy Act of 2005¹⁵ added several significant reforms that enhanced FERC's jurisdiction and authority, even though there was no firm endorsement of retail competition or restructuring in the new federal law. Even so, the 2005 Energy Act significantly expanded FERC's jurisdiction as follows:

- Providing FERC with the power to adopt enforceable reliability standards for the electricity transmission grid with increased penalties for failure to comply with these new standards;
- Clarifying and improving FERC's ability to adopt regulations and conduct oversight of the wholesale market to prevent market manipulation such as that which occurred in

California with added enforcement authority concerning its rules and orders, and allowing FERC to order refunds to affected customers when wholesale contracts are found to be based on market manipulation or discriminatory terms;

- Implementing new tools, including penalty authority, to prevent market manipulation;
- Allowing FERC to establish rate incentives to promote electric transmission investment;
- Providing for the potential of federal preemption of state transmission siting decisions in “national interest electric transmission corridors”;
- Repealing the 1978 PURPA obligation imposed on utilities to purchase power from QF’s;
- Repealing the 1935 Public Utility Holding Company Act and substituting a FERC review of certain holding company mergers and acquisitions involving electric utility facilities, as well as certain public utility acquisitions of generating facilities; and
- Adopting a new federal policy statement in PURPA that endorses time-based pricing for all customers and customer access to advanced metering to implement a variety of time-based pricing options.

The 2005 Energy Act contains no mandate to the states concerning the market structure that should be adopted for retail electricity or natural gas markets and it specifically states that the formation of Regional Transmission Organizations by utilities is voluntary. However, it would certainly be correct to interpret the 2005 Act as doing nothing to halt FERC’s ongoing effort to develop and promote the reliance on market-based prices to govern transactions in the wholesale market.

The Energy Independence and Security Act adopted in late 2007¹⁶ made no significant changes to FERC’s jurisdiction or overall mandate, but does contain additional policy endorsement for the “smart grid” with even stronger than the language adopted in the 2005 Energy Act.

Whether explicit or not, FERC interprets its mission as seeking to broaden and develop competitive wholesale markets. In its most recent Strategic Plan, FERC states its mission as follows:

Goal 1: Energy Infrastructure: Promote the Development of a Strong Energy Infrastructure

Objective A: Stimulate Appropriate Infrastructure Development

- Resolve regulatory and other challenges to needed development
- Encourage investment and effect timely cost recovery

Objective B: Maintain a Reliable and Safe Infrastructure

- Assure reliability of interstate transmission grid
- Protect safety at LNG and hydropower facilities
- Incorporate environmental considerations into Commission decisions

Goal 2: Competitive Markets: Support Competitive Markets

Objective A: Develop Rules that Encourage Fair and Efficient Competitive Markets

- Employ best practices in market rules
- Reduce barriers to trade between markets and among regions

Objective B: Prevent Accumulation and Exercise of Market Power

- Assure proposed mergers and acquisitions are in the public interest
- Address market power in jurisdictional wholesale markets

Goal 3: Enforcement: Prevent Market Manipulation

Objective A: Provide Vigilant Oversight

- Identify and remedy problems with structure and operations in energy markets

Objective B: Provide Firm but Fair Enforcement

- Establish clear and fair processes
- Conduct investigations promptly and impose penalties where appropriate
- Encourage self-policing and -reporting of violations

When asked why its priorities do not include the statutory obligation to assure “just and reasonable” prices, FERC and its leadership has repeatedly responded that the formation and implementation of competitive markets will deliver reasonable prices more efficiently and at a

lower cost to consumers than the more traditional regulatory approach. Furthermore, the fact that Congress has not halted this development has meant that the stage was set for the federalization of retail prices with the elimination or expiration of rate caps and rate freezes that most states had adopted with the onset of retail restructuring beginning early in the 21st Century.

III. FERC'S IMPACT ON AND ROLE IN REGULATING ELECTRICITY PRICES: KEY INITIATIVES AND POLICIES

A. FERC Moves From Filed Rates To “Market-Based” Pricing

FERC uses its authority to regulate the prices and the access to the transmission system and its authority over prices for wholesale market sales between privately-owned generators and public utilities and between public utilities to further its objective of creating a competitive wholesale market. These policies have been controversial in part because the states have not adopted the same market model for regulating electricity. While approximately 20 states have formally adopted retail competition and sought to enact retail competition markets for the sale of generation supply, the other states have firmly held on to their traditional role of regulating the cost of service for generation supply service and retained their oversight of public utilities. Where restructuring has taken hold, the utilities have either sold their generation supply facilities or transferred ownership to affiliates that are not “public utilities” as that term is defined in most states. By virtue of this actual or structural divestiture of generating facilities, the restructuring states have given up their authority to regulate the prices charged by these facilities and effectively transferred control of the prices charged by these generation supply owners to FERC.

Regulation of Transmission Service FERC directly regulates the price charged by the owner of transmission for this service because these transactions occur in interstate commerce. “Transmission” is defined as a service that uses the very large capacity transmission lines that connect the electric grid between utilities and that ship electricity from generating facilities to local distribution networks. In most cases, the local public utilities built and still own the transmission system, but in restructuring states the utility has agreed to transmit the actual

operation of this system to regional wholesale market entities regulated by FERC. FERC's recent efforts to supervise the rates and prices for this service have required that transmission service be unbundled from generation and distribution services and that the price for the use of the transmission system (typically owned by utilities) is not discriminatory and that any generator can gain "open access" to this system at a reasonable price.

The controversies that have arisen with respect to this approach have consumed vast quantities of litigation and paperwork. Independent generators and those who seek to buy power in the wholesale market frequently allege that the pricing criteria reflected in the transmission owner's tariff result in discrimination, alleging that customers of the utility (often referred to as "native load" in these debates) have had preferential treatment, that the prices do not reflect the true costs in transmission-constrained areas (areas in which there is insufficient transmission capacity to carry all new generation supply output), or that the prices should load the costs of new transmission facilities onto those generators who are asking for such new facilities to serve their output.

Obviously, the overall interest of those who have complained about being subject to discriminatory conduct or pricing from transmission owners reflect a wide range of interests, some of whom seek to "socialize" the costs of new transmission to all entities and customers and others who seek to impose the costs of new transmission needs on those customers who would benefit from relieving the current congestion on the system. Another way to picture this problem is to consider the transmission congestion that affects the Boston, Massachusetts area. While lower cost generation could be accessed to help reduce electricity prices, that generation is located outside the transmission constrained area; there is not enough transmission capacity to

bring in new generation. Should the customers located in Boston pay to solve this problem by constructing new transmission facilities or should all the customers served in the regional wholesale market pay a small increase to solve this problem?

FERC requires utilities or other owners of transmission to file an Open Access Tariff and requires by rule¹⁷ and mandates open and transparent planning for new transmission resources on both a local and regional level. This rule purports to retain the historical jurisdiction of the states over a bundled retail load price provided by a vertically integrated utility, as well as the protection for serving the “native load” of a utility that owns transmission facilities.

In addition to regulation of transmission service prices, FERC now has the authority to override a state’s refusal to site transmission facilities in “national interest electric transmission corridors” that are designated by the Department of Energy in areas where there is significant transmission congestion (i.e., where there is insufficient transmission capacity to handle load at peak periods or where generators cannot get access except under very high prices due to the lack of availability of the system resource). FERC has yet to exercise this authority and it is sure to be very controversial when it does so because of the potential impact on local and state environmental and land use planning decisions.

Regulation of Wholesale Market Prices for Electricity FERC has moved away from the traditional cost-based regulation of sales transactions or contracts in which prices were specifically approved by FERC and then “filed” as a tariff or other means of reflecting a regulatory approval. Unless any party objected, the FERC approval and the “filed rate” was interpreted to mean that the costs were reasonable and reflected a fair rate of return. Instead, FERC has established a regulation that sets forth the criteria by which a utility or generator can

obtain authority for “market-based” regulation. Under this approach, if the applicant meets the regulatory criteria, there is no review or analysis of the prices charged by that entity by FERC unless there is a complaint by another market participant. Buyers and sellers can strike long term bilateral deals, but actual contract prices are not filed and there are no “tariffs” that reflect publicly available prices. Recently, FERC revised these criteria to obtain market-based authority and avoid the traditional requirement to file rates and tariffs.¹⁸ Under this rule, FERC will evaluate both horizontal market power and vertical market power by means of predetermined market power criteria. As part of the latter analysis, a seller that seeks authority to charge market based rates who owns transmission facilities has to have a Commission approved open access transmission tariff on file. Only the larger generators/sellers who also own transmission facilities must file a regular updated market power analysis.

This approach by FERC in allowing “market based” prices rather than exerting its authority to employ cost-based rates through the traditional analysis of costs and revenues and the elimination of filed rates has been the source of significant litigation and controversy. Opponents of FERC’s approach argue that there is no statutory basis for FERC’s policy in this regard since the basic provisions of Section 205 of the Federal Power Act that require “just and reasonable rates”, filed rates, published tariffs, and opportunity to comment on any proposed rate have never been amended by Congress. The potential impact of this new structure developed by FERC has grown exponentially as a very large proportion of the electricity now sold by generators in certain parts of the country is now subject to FERC jurisdiction rather than the traditional oversight of state regulators. This change is particularly important for residential customers because state Default Service policy has moved away from long term bilateral

contracts and utility-owned generation and relies instead on purchasing generation supply service through wholesale market contracts that reflect short-term energy pricing trends and the impact of the regional wholesale market pricing structures.

The Rise of Administered Regional Markets Of particular significance in this regard is the development of new regional markets for short-term transactions necessary to balance supply and demand and to maintain system reliability. In these markets electricity is purchased and sold through centralized regional or “spot” markets operated by an independent system operator (“ISO”) or a regional transmission operator (“RTO”).

FERC’s preference for regional entities to actually operate the regional transmission systems and establish the means by which wholesale prices are established began with Order 888 adopted in 1996. This Order encouraged the development of Independent System Operators or power pools to govern the dispatch of generation facilities to meet the expected daily and hourly output necessary to govern the usage or load on the transmission system. Voluntary regional entities in New England and the Mid-Atlantic states (the precursor to PJM) were formed for this purpose in the 1980’s or even earlier. However, the overall structure and function of these voluntary regional entities took on even new meaning and purpose with FERC’s Order 2000 issued in late 1999, after most of the New England and Mid-Atlantic States had adopted restructuring. Order 2000 set forth FERC’s vision for Regional Transmission Organizations in which the underlying owners of transmission would transmit either ownership or authority to operate the transmission system on behalf of the owners, thus eliminating the direct control over the transmission system held by the utilities who were the typical builders and owners of the transmission systems. In this Order FERC set forth 12 criteria for the formation of an RTO and

FERC's approval of such an application. Most of these criteria related to the independent governance of the transmission system, the oversight for the implementation of the access to the transmission system, and, important for its impact on electricity prices, methods to assure reliability of service so that the load being served is instantly balanced with the supply being offered to serve that load. Under these criteria, FERC began approval of formal RTOs in 2001. One of the first approvals was for the PJM Interconnection in July 2001.¹⁹

Generally, the regional markets utilize a single-price auction mechanism where the price is established as follows: (1) sellers bid in an offering price and amount of energy for each hour (or even shorter periods as determined by the RTO or ISO); (2) bid "stacks" are created, beginning with the lowest-priced bids and continuing up to the highest-priced bids; and (3) the amount of energy offered is added up, starting with the lowest bid and going up the "stack," until the total amount of electricity needed by underlying load (retail consumers) is reached; (4) the price of the last-needed (and therefore the highest-priced) bid sets the price for the entire bid stack. The latter is called the "market clearing price." Thus, even a seller that bid to sell energy at a lower price receives the higher market clearing price.

To date, the litigation to challenge FERC's use of "market based" pricing as a contravention of the Federal Power Act has failed to result in a change in FERC's approach and the agency continues to push forward with the development of competitive markets that eliminate filed rates and relies on its market power approach to regulating wholesale market prices. Probably the most significant case was *California, ex rel., Lockyer v. FERC*, one of many court cases that sought to review the reasonableness of certain wholesale market contracts that FERC refused to overturn as a result of the Western energy market energy implosion in 2001-2002. In

this case, the U.S Court of Appeals 9th Circuit upheld FERC's approach of not requiring filing requirements for such contracts if the entities lacked market power. In 2007, the U.S. Supreme Court left this decision in place²⁰ (that is, it refused to accept the case for review) and FERC treats this result as "remov[ing] any remaining question about our legal authority to authorize market based rates."²¹ However, another proceeding that challenges this same FERC authority is pending before the U.S. Supreme Court and is likely to result in a decision in 2008.²²

B. FERC's Wholesale Market Design Emphasizes RTO Formation and Spot Market Prices

FERC has tried to force the creation of Regional Transmission Organizations in which the owners of transmission facilities give up their authority to control access to such facilities to a regional organization that is operated by a separate non-profit corporate entity formed by the underlying stakeholders. However, these regional system operators do far more than regulate access to the transmission lines. It is they that have established the regional "day-ahead" or spot markets to regulate the price of electricity that is sold on the wholesale market, making use of the interstate transmission system.

In late 1999, FERC issued Order 2000²³ which, while stating that its intent was to seek voluntary formation of an RTO, appeared to threaten the possibility of a formal requirement that all public utilities form an RTO:

Our objective is for all transmission-owning entities in the Nation, including non-public utility entities, to place their transmission facilities under the control of appropriate RTOs in a timely manner. Therefore, we are establishing in this rule minimum characteristics and functions for appropriate RTOs; a collaborative process by which public utilities and non-public utilities that own, operate or control interstate transmission facilities, in consultation with state officials as appropriate, will consider and develop RTOs; a proposal to consider transmission ratemaking reforms on a case specific basis; an opportunity for non-

monetary regulatory benefits, such as deference in dispute resolution and streamlined filing and approval procedures; and a time line for public utilities to make appropriate filings with the Commission to initiate operation of RTOs. As a result of this voluntary approach, we expect jurisdictional utilities to form RTOs. If the industry fails to form RTOs under this approach, the Commission will reconsider what further regulatory steps are in the public interest.

In 2002, FERC reached its zenith of attempting to assure that its vision of competitive wholesale market design would be adopted. In July 2002, FERC issued a Notice of Proposed Rulemaking (NOPR) with “a series of sweeping changes to bring to fruition the kinds of markets envisioned—and advanced—in key Commission Orders Nos. 888 and 2000 but not yet realized.”²⁴ Known as the attempt to establish a Standard Market Design, FERC stated:

Central to the standard market design concept is its reliance on bilateral contracts entered into between buyers and sellers. The proposal would require transmission service providers to be independent of market participants and to establish short-term electricity markets to complement bilateral contracts. To handle generation imbalances and the procurement of ancillary services, the Commission proposes to require that independent transmission providers operate voluntary short-term markets for energy and operating reserves in conjunction with markets for transmission service. These markets would be bid-based, security-constrained, spot markets operated in two time frames—a day-ahead of real-time operations and in real time. The adoption of a market-based locational marginal pricing (LMP) transmission congestion management system is designed to provide a mechanism for allocating transmission capacity to those who value it most. The system would encourage efficient provision of transmission service and encourage the development of needed transmission, generation and demand response infrastructure.

The NOPR requirements would be mandatory for all public utilities that own, operate or control transmission facilities in interstate commerce. The Commission expects that the requirements of the NOPR will be met through regional transmission organizations (RTOs), but if a public utility chooses not to join an RTO, it will have to contract with an independent entity to perform certain requirements. Regional flexibility in certain areas would be allowed. This will ensure the continuation of a strong role by state regulatory authorities in helping to assure resource adequacy. Under today's proposals, all public utilities that own, control or operate interstate transmission facilities must file at certain dates following the final rule interim open access transmission tariffs that include bundled retail customers as eligible to receive service. Further, all independent transmission providers must file Standard Market Design (SMD) tariff. The Commission intends to rely on these filings to ensure that all public utilities that own, control or operate interstate transmission facilities will be operating under SMD unless otherwise directed by the Commission.

The reaction to this proposal highlighted the disparities among the states in the form of retail market model then in effect. Those states that had adopted retail competition and restructuring had already endorsed or helped to form an RTO or moved to do so under the FERC

minimum principles. However, those states (primarily in the West and in the South) that had not adopted retail competition and restructuring resisted this approach and many commenters alleged that the failure of the “market” in the California experience in 2000-2001 clearly indicated that such an approach may hold dangerous consequences for consumers. The widespread controversy over FERC’s suggestion that it had the authority to order the public utilities to engage in a “standardized” wholesale market design and force the use of the RTO model resulted in FERC’s acquiescence to a more voluntary approach in 2003. On April 29, 2003, FERC issued a “White Paper on Wholesale Power Market Platform,” which pulled back from the mandatory approach to form an RTO and the market structure model proposed by FERC in 2002. As a result, FERC pulled back from what appeared to be heavy handed push for RTO formation, an approach that culminated in the language of the Energy Policy Act of 2005 that specifically states that federal policy is that the formation of an RTO is voluntary. Even so, the formation of RTOs continue, in part due to the push for their formation by the now independently owned generators who were formally regulated by state authorities and who now clearly prefer to operate in the regional markets administered by FERC-approved RTOs.

Formal RTOs now exist at ISO New England (New England), NYISO (New York State), PJM Interconnection (Mid-Atlantic and some Mid-West states), MISO (Midwest Independent Transmission System Operator (upper Mid-west states), California ISO, SPP (Southwest Power Pool, including Oklahoma and Kansas) and ERCOT in Texas. ERCOT is not regulated by FERC, but by the Texas PUC.²⁵ States whose utilities do not belong to a formal RTO or ISO include most of the Western and Southern states that have not adopted retail restructuring and who have resisted FERC’s push for standard market design. The RTO’s (with the exception of

ERCOT) have filed a formal organizational plan and structure with tariffs that are then approved by FERC. RTO's have formed nonprofit organizations that are not directly subject to state regulation, although state regulators are integrated into the various stakeholder committees and voting structure. Rather, by means of their tariffs and organizational structure approved by FERC, they operate pursuant to federal policies. All of the organized RTOs have established "day-ahead" or spot market pricing methods that rely on Locational Market Pricing for transmission services as set forth in the FERC 2002 Standard Market Design proposal. Under this approach the price of electricity varies with the degree of constraint that is reflected in hundreds of separate locations on the electric grid.

RTO's are also intimately related to another regional organization called Independent System Operator (ISO). An ISO has direct control over the dispatch of the region's generating facilities. These organizations, some of which have the same boundaries and organizational structure as the RTO, are formed to actually dispatch generation resources within their jurisdiction and oversee the operations of the wholesale electricity market.

The largest RTO is PJM Interconnection which coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. PJM monitors the high-voltage transmission grid and keeps the electricity supply and demand in balance by telling power producers how much energy should be generated and by adjusting import and export transactions.

Where an RTO has been approved, it plans and identifies the need for new or expanded transmission facilities because all the member utilities have transferred either ownership or

control of long distance transmission facilities to the RTO. This contrasts with the historical state role of assuming responsibility for assuring long term reliability of supply and the underlying transmission facilities necessary to meet those needs.

Furthermore, an RTO also operates the wholesale electricity market by establishing the structure by which prices are “regulated” for wholesale transactions. This is done by using tools that are similar to those used in a stock exchange. Buyers and sellers see “real time” data on spot market prices, using the “bid stack” approach so that the price of the most expensive generator used to meet the last amount of energy needed for the increment (15-minute or one hour or day ahead) sets the price for the entire load bid into that stack. This approach does not eliminate bilateral contracts directly between utilities and generators. Such bilateral contracts are not publicly reported, however, and it is difficult to know to what degree the prices in the short-term markets determine the price by contract under longer term bilateral arrangements. Most importantly for residential customers, however, is that state regulators have rejected longer term bilateral contracts to provide default service and ordered local utilities to buy relatively short-term wholesale market contracts that reflect these short-term RTO market prices.

Prices are even more complicated with the move to Locational Marginal Pricing or LMP, a pricing mechanism highly favored by FERC for RTOs. Under this approach, prices are set at the various “nodes” that mark the location of underlying loads and the existing transmission network. A different price is set for each “node” to reflect the long term marginal price to meet the load in that area. This allows for significant pricing distinctions between areas that have transmission constraints and those that have generation surplus. For example, the metropolitan area of Boston is “transmission constrained” because there are insufficient transmission facilities

to allow for lower priced generation outside this area to be imported and compete with generation facilities that are located within the existing transmission grid that serves this area. As a result, the LMP for energy in the Boston area is higher than the LMP for areas in Maine which generate a surplus of generation supply compared to the load needed to serve Maine. Under the FERC theory these price differentials create incentives for investment in additional transmission and/or generation to serve the constrained area, thereby relieving the congestion.

Finally, an RTO assumes long term planning for new generation resources by identifying long term capacity needs and resources and assuring the long term reliability of supply and demand. This has vastly expanded the role of these federally-regulated entities in setting up new markets to assure investment in new capacity and stimulated the development of RTO-controlled demand response programs as well.

As part of what the RTO considers as its mandate to assure long term reliability of generation supply and transmission resources, these entities are now heavily involved in the development of a new mechanism to assure the adequacy of new long term generation capacity. Both ISO New England and PJM now operate “forward” capacity market auctions in which entities bid to provide capacity resources for a future three-year period. While governed by a complicated formula, the basic result is that costs associated with the winning bids are then allocated to all load serving entities (i.e., generation supply facilities). These new market mechanisms have been controversial, but FERC has approved these proposals by the RTOs. Included in these auctions and forward capacity markets are demand response and, in New England, energy efficiency programs. Those who seek to offer or operate such programs can bid

into the capacity market and receive payments for providing specific peak load demand reduction or overall usage reduction services that will substitute and avoid the need for constructing new generation facilities.

As a result of these many initiatives promoted by FERC and reflected in the governance of the various RTOs, the traditional state authority over management of the generation supply portfolio of their public utilities have been eroded and, where restructuring has taken hold, almost eliminated.

IV. HOW DOES FERC’S APPROACH TO PRICING FOR TRANSMISSION AND WHOLESALE GENERATION SUPPLY IMPACT RETAIL CUSTOMERS, PARTICULARLY RESIDENTIAL CUSTOMERS?

There are three key roles that FERC and its approved RTOs play in influencing electricity prices paid by residential customers. These three key influences have, with the support of some state regulators and other state policy makers that have supported the move to restructuring, reduced the role of state authority or influence in setting retail prices.

A. The Manner In Which RTO’s Have Structured Their Markets and the Policy Decisions of State Regulators Have Contributed to High Priced Default Service For Residential Customers.

Whether or not FERC intended that bilateral contracts would continue to provide the backbone of the wholesale market transactions, these transactions or contracts do not appear to be the basis for retail electricity prices in states that have adopted retail competition. Rather, pursuant to directives in the state restructuring statute or as a result of discretionary policy decisions, state regulators have emphasized the importance of basing retail electricity prices on the wholesale “market” price. By “market” price, most state regulators have relied on the prices charged for one type of wholesale market contract—full requirements contracts—that reflect fixed prices for a 1-3 year period. These contracts are primarily supplied by wholesale market suppliers that own generation or who can acquire generation and then re-sell that power in auctions and in response to Requests for Proposals issued by utilities.

The winning bidders in these acquisitions are typically the generation suppliers that were regulated by state authorities as public utilities, but who are now independent of state regulation.²⁶ These bids and prices typically reflect spot market developments and include premiums in the form of higher prices in return for the fixed price bids. In other words, the volatile wholesale market prices that were originally intended to reflect the need to balance short-term supply and demand on the transmission system have now become the basis for retail electricity pricing policy. The highest prices charged by the generator who provides the last increment of power in the bid stack has allowed the lower priced base load plants (typically, coal or nuclear plants or, in some areas, hydropower dams) to obtain a much higher price than might have been obtained under traditional cost of service regulation.

The results have been dramatic increases in the price of electricity generation supply service for residential customers, most of whom obtain electricity from as Default Service from the local distribution utility. Furthermore, because these short-term markets are very susceptible to the potential for market manipulation and the impact of fuel prices on the national and international stage, retail prices have become more volatile as well.

It is important to note as well that the actual structure of the wholesale market and the adoption of “bid stack” pricing, the formation of RTOs, and FERC’s policies with respect to the design of the wholesale market occurred AFTER these states adopted retail restructuring. As a result, when the policymakers of those states sought to introduce “market” or “competitive” forces into the pricing for essential electricity service, there was no organized wholesale market in existence so there was no real world indication as to how retail electricity prices would be influenced by policies that FERC might adopt to govern the creation of RTOs or other means of

administering wholesale markets. Unfortunately, the first indication of what may occur with retail prices in a restructuring world suggested that retail customers were being sent out to sea on a very leaky boat with few oars or life preservers.

The nature of the California and Western market implosion that occurred in 2000 and lingered into 2001 had a significant impact on the nature of the reforms that were adopted in other Western States because the market meltdown that occurred in the California restructuring model affected retail prices for customers in the entire region. However, other states failed to confront these issues in part because the rate caps masked the need for reforms in other restructured states and the impact of the wholesale market structure that was under development in the New England, New York, and Mid-Atlantic regions was not fully anticipated or understood by many observers at the state level. While most states and state regulators were nervous about the implications of the California energy crisis in 2000-2001, the New England and Mid-Atlantic states that had adopted restructuring in 1998-1999 had done so with fairly long rate caps or mandatory rate decreases for residential customers that remained in place until 2002 (New Jersey), 2004 (Massachusetts and Rhode Island), 2006 (Maryland for the largest utility, Delaware), 2007 (Illinois) and even longer (2010-2011) for some larger utilities in Pennsylvania. Other states, such as Maine, never adopted any rate caps or transition rates for retail customers. These states forged ahead to develop a retail market for the sale of electricity and supported the development of the RTO structure for the wholesale market that was being promoted by FERC.

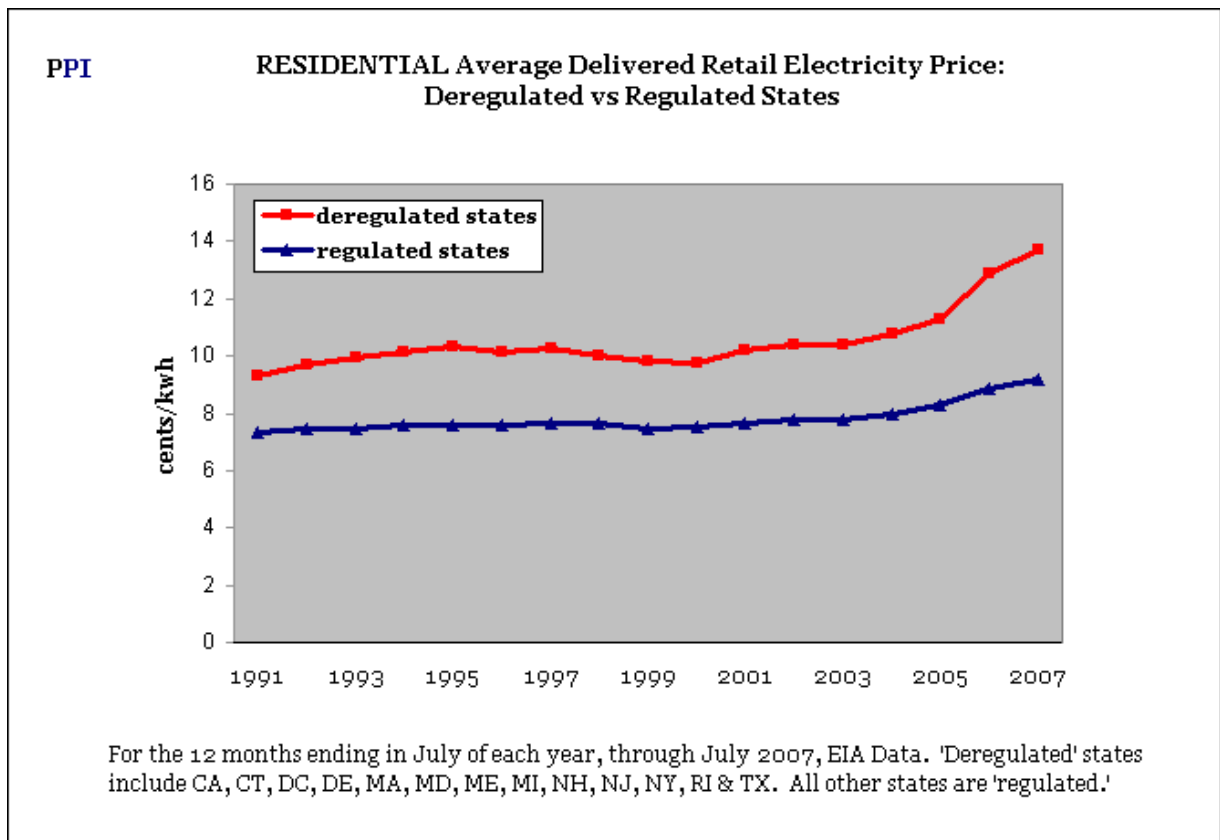
When they were required to confront the need for a Default Service at the end of the rate cap or transition period, most states ordered the incumbent utilities to go into the wholesale market to obtain relatively short-term contracts so that customers would see “market-based”

prices for electricity. The assumption was that these new markets would result in lower cost new generation being sold in competition with the older and more expensive generation supply assets formerly owned by utilities. The first major reform adopted in these states was to establish a policy to obtain fixed rate contracts for residential and small commercial customers with varying contract terms, typically 1-3 years. In addition, these states gradually moved to “ladder” the contracts so that 100% of the load was not obtained at one point in time and prices moved annually to reflect the newly acquired contracts for 30-50% of the entire contract load obligation. For the most part, these reforms were designed specifically to avoid the initial approach ordered in California which had required the utilities to pass through wholesale “day-ahead” or “hourly” real time prices to retail customers. In addition, these reforms were viewed as ending the reliance on regulated prices (in the form of the rate caps) and exposing customers to “market” prices, thus allowing retail suppliers to come in and offer better or different prices to all customers.

The increasing attention to Default Service was due to the fact that retail competition did not develop for most residential and small commercial customers during the rate cap period. In part, this failure was due to the fact that wholesale market prices rose higher than the rate caps or rate decreases that were put into effect at the time of restructuring. These “market” prices reflected the emerging reliance on the wholesale spot market as the basis for determining the price for electricity. In the view of most of these state regulators, these RTO prices that reflected the price of the highest cost generator in the bid stack were in fact the “market” prices that had to be passed through to all customers to obtain the long term benefits of a competitive market and stimulate the development of new generation resources.

Whatever the reason, the retail prices for Default Service in restructuring states is higher than the price for comparable service in states that did not adopt restructuring. Furthermore, prices for electricity in states whose utilities have joined an RTO are generally higher than prices in states in which utilities are not governed by RTOs.

This phenomenon has been well documented. The following chart from Power in the Public Interest²⁷ shows the average price differential for residential customer prices for electricity between those states that have adopted restructuring and those that have not done so:



As the chart clear demonstrates, the price differential between these two groups of states has increased since restructuring was adopted so that the historical difference between the

restructuring states, many of which had higher historical prices for electricity compared to other parts of the country, has been exacerbated by restructuring. This is exactly the opposite of what public policymakers promised would occur as a result of adopting restructuring and retail competition.

These prices are higher than the average cost rates charged by utilities prior to the adoption of restructuring and that higher price cannot be explained by fuel costs alone. This Paper is not able to discuss in any detail why this has occurred,²⁸ but that fact coupled with the lack of interest in serving residential customers by competitive suppliers, has resulted in the necessity for the state regulators to arrange for Default Service for almost 100% of the residential and small commercial customers.

Even when retail marketers made offers to residential customers, most customers appeared uninterested, particularly when the “savings” offered by the retail marketer were 10% or less than the Default Service or rate capped price. Almost no competitive energy suppliers have ever made significant inroads to the residential customer markets in New Jersey, Maryland, Delaware, Rhode Island, Massachusetts, Pennsylvania, Illinois, Michigan, Connecticut, or Maine. In these states, less than 5% of these customers have selected an alternative provider, even though there is no rule or policy that prohibits or inhibits marketers from soliciting customers or customers from selecting a marketer.²⁹

The New Jersey experience was typical of all the restructuring states. New Jersey enacted restructuring with an effective date of August 1999. While not required to do so, utilities were enticed to either divest generation assets or transfer them to separate affiliates. The largest utility, Public Service Electric and Gas, did not sell most of their generation assets, but

transferred them to an affiliate. The New Jersey restructuring law mandated electric rate reductions of at least 5 percent upon implementation of the Act and at least 10 percent by the beginning of the fourth year of deregulation.

In December 2001 the New Jersey Board of Public Utilities (Board) determined that for year 4 of the transition period, i.e., August 2003-August 2004, electric utilities should continue to provide Default Service (referred to as “Basic Generation Service” or BGS in the NJ law) by buying electricity through standardized contracts in the wholesale market. The price for these contracts would be determined by a state-supervised auction process. The Board has approved this process since 2002 and has ordered that service for residential and small commercial customers be provided at a fixed price that changes every year according to the results of the auction. Rather than requiring that the entire Default Service portfolio be acquired at once, the Board has moved to a “laddered” contract approach in which 1/3 of the load is acquired every year for a three-year fixed price.

As a result, New Jersey established the model for the notion that Default Service should be based on competitively acquired wholesale market “full requirements” contracts that are for relatively short durations, 1-3 years, but at fixed prices, at least for residential and small commercial customers. Prices under the New Jersey auction resulted in price increases compared to the pre-restructuring prices, but starting in 2006, dramatic price increases were reflected in the wholesale market contracts. However, because of the laddered nature of the contracts, the full impact of the 2006 prices was muted because the high 2006 prices were blended with the previous auction results in the price for generation supply that appeared on customer bills. The 2007 prices resulted in an even higher impact. The generation supply price for residential

customers has increased 100% since 2002. Beginning in 2008, residential customers of the larger electric utilities will pay over 11 cents per kWh for generation supply service. In each of the last three years, the impact of these wholesale market contracts has caused a double digit increase in the average residential customer bill for electricity. Residential customers of Public Service Electric and Gas have seen the price of the generation portion of the bill increase from 5.11 cents per kWh in 2002 to over 11 cents per kWh as of 2008. Of course, these prices reflect only the generation portion of the bill and do not reflect distribution or regulated services.

Only Illinois has adopted the same structure for an auction for Default Service contracts as developed by New Jersey, but other restructuring states, such as the District of Columbia, Maryland, Delaware, Massachusetts, Rhode Island, Maine, and Pennsylvania have followed the policy of relying on a laddered mix of fixed price 1-3 year wholesale market contracts to serve residential and small commercial customers. These contracts are standardized and awarded to wholesale market power generators based on a competitive bidding process supervised by the state regulator. The resulting prices for these wholesale market contracts for Default Service for residential customers have been similar to the results seen in New Jersey, i.e., a period of relatively mild price increases in the early years, followed by dramatic price increases beginning with contracts obtained in late 2005 and early 2006. In 2008 the typical residential price for generation supply service in these states is between 10 and 11 cents per kWh.³⁰

As a result of the prices that have flowed by from FERC-regulated RTO markets combined with the policies that state regulators have adopted to provide Default Service, residential customers are now paying a price for generation supply service that reflects short-term contracts supplied for the most part by formerly regulated generation supply facilities at a much

higher price than such customers paid for this same service from these same facilities under traditional cost of service regulation. While larger industrial customers can self-build or negotiate a long term contract to suit their particular needs with an individual generator, regulators have established Default Service policies that require the local utility to buy electricity for residential customers pursuant to solicitations or auctions that do not reflect long term prices or long term contracts. Nor do these Default Service portfolios reflect the integration of energy efficiency and demand response programs that might ameliorate the impact of short term wholesale market prices for traditional generation supply resources. Even where states have expanded or considered expansion of energy efficiency programs, they are typically being funded through regulated distribution rates or surcharges that are not integrated into the Default Service generation supply price.³¹

It would be reasonable to ask why owners of generation services, either old or new, have not sought to provide their services under longer term contracts or outside the current RTO structure. Part of the answer, as noted above, is that state regulators have often limited the ability of distribution companies to buy electricity under long-term contracts. Even where such options have been proposed the “independent” owners of generation supply facilities that operate in the wholesale market under FERC jurisdiction have strongly opposed such an approach, urging state regulators to avoid the high-priced PURPA contracts that contributed to the movement toward restructuring in the 1990’s. In addition, older generation facilities (no longer owned by utilities or owned by an affiliate of a utility, neither of which is subject to state regulatory authority) have enjoyed considerable profits in selling their electricity in newly designed wholesale markets.

This is because older baseload coal and nuclear plants have every incentive to become more efficient and sell their output into a market system that rewards them with a price that is higher than their actual underlying cost structure. That higher price is typically governed by the highest priced fuel, which in most of the New England and Mid-Atlantic markets is natural gas. Therefore, when the last facility called upon to meet the expected load in a given time period is a more expensive peak load natural gas fired generating facility, all the generation facilities that bid into that time period or stack are paid the price necessary to meet the bid of the natural gas generator. There is no incentive for these older baseload generating facilities to try and undercut the high price charged by the natural gas generators because they are making more money with the current system than they could by selling their output directly to end-use customers.

B. How Has Federal Policy Responded to Higher Electricity Prices?: The Push for Regional Capacity Markets and Demand Response Programs.

Higher electricity prices have resulted in renewed efforts to assure investment in new capacity, renewable resources, and demand response programs, all of which have been lacking in the restructured markets. While states traditionally required utilities to undertake long term and integrated resource planning to assure the appropriate level of demand programs in the total generation supply portfolio, restructuring shattered the connection between state planning and long term “thinking” about the generation supply portfolio. FERC has attempted to respond to this gap in planning by promoting a variety of new initiatives.

Federal Control and Pricing to Assure Reliability and New Generation Supply Resources

The larger RTOs, such as PJM and ISO-New England, have established

new rules designed to stimulate investment in new capacity for their markets. These initiatives have been undertaken to ensure the long term reliability of the bulk power market. These planning programs and the resulting rules to establish a new capacity market are also subject to FERC's jurisdiction. Central to these policies is the reliance on locational prices to send the proper price signal for investment in new capacity, as well as investment in new transmission facilities. Locational Marginal Prices or LMPs reflect the impact of transmission congestion, line losses, and other factors that differentiate energy prices at individual points across the regional market. Transmission congestion occurs when constraints on the transmission system prevent the most economical (lowest cost) source of generation from being delivered to those who need the electricity (local load), thereby requiring more expensive generation within the local load pocket to be used instead. The additional costs of meeting the supply needs of the load pockets without sufficient transmission capacity result in higher prices when energy is priced based on this FERC-approved methodology. As explained in the earlier section, FERC favors market rule structures in which the highest priced generator that bids to provide service at the most expensive hour of the day sets the price for all the generators needed for that hour. This approach is exacerbated by the reliance on LMPs because under PJM and FERC market rules, when these local, "marginal" generating units are dispatched to serve load pocket areas, they set the price **for all units** operating in the zone, even lower cost units. A direct consequence is that when higher cost generation must be dispatched to serve a load constrained zone to meet the demand for electricity, overall electricity prices will be higher in that zone.

According to the Maryland Public Service Commission, one of its consultants has estimated that for 2008, congestion will add over \$160 million in costs to residential default

service prices and the PJM market monitor estimated that gross congestion costs for all of Maryland (not netted with any offsets) in 2006 were \$1.2 Billion. Actual costs could be as much as \$500 million.

Furthermore, in an effort to promote resource adequacy objectives, RTOs are designing and implementing a capacity resource model that was intended to provide sufficient cash flows to assure continued performance from incumbent generators needed for reliability and to provide incentives for investment in new generation. Other independent system operators in New York and New England have also implemented capacity payment mechanisms to meet comparable objectives. PJM's capacity resource model – the Reliability Pricing Model (“RPM”) – began payments effective June 1, 2007, and replaced the previous capacity payment procedures, which did not differentiate capacity prices by location within PJM. FERC concluded that the previous capacity payments model discouraged investment, thereby jeopardizing resource adequacy requirements, especially in transmission constrained zones. As a result, PJM's RPM uses a “sloped-demand curve,” which was designed to provide generation companies with a more predictable revenue stream. RPM was intended to provide locational price signals for capacity resources and load obligations, thereby encouraging long-term resource adequacy goals consistent with the PJM Regional Transmission Expansion Planning (“RTEP”) process. The program relies on auctions to determine capacity prices for individual years. PJM sets the clearing price at the intersection of a supply curve – made up of capacity bids from generators and demand resources – and an administratively determined sloped Variable Resource Requirement (“VRR”) demand curve.

The PJM auction results clearly demonstrate the impact of relying on LMPs and the structure of the auction to reflect capacity and transmission constrained locations in the auction structure. The 2007-2008 RPM payments to generators will average \$40.80 per MW-day in PJM as a whole, but in the area served by the largest utility in Maryland (BGE), the payments will exceed \$188 per MW-day. Even higher prices over \$200 per MW-day will be paid in 2009 and 2010. These auctions have resulted in payments to generators, supply resources, and approved demand response resources that are then reflected in energy prices to retail customers. Where transmission constraints are severe, such as in the Delmarva Peninsula, the impact on energy prices flowed through to default service customers is significant. As stated in a recent report issued to Maryland's Public Service Commission:

The results of these RPM auctions indicate that customers in Maryland will be paying higher capacity costs until (i) at least one major transmission import project is completed, (ii) significant in-State generation capacity is constructed, or (iii) enough demand response is developed to reduce demand significantly.³²

Smart Meters and Time-Based Pricing to Achieve Demand Response In particular, both federal law and FERC have pushed for the adoption of Advanced Metering and promoted the notion that if all customers could be exposed to “real time” prices for electricity, better choices would be made to reduce usage during peak hours when the most expensive generation supply resources are needed to serve the load. Federal policy, some state regulators, and economists who advocate for “sending the proper price signals” to all customers support the installation of “smart meters” and changes in how electricity is priced. In some cases, customers will be offered the option of “time of use” or “critical” pricing programs that vary the price of

electricity by the time of day or the volatile prices of a wholesale spot market. In other cases, customers will be offered the option of interrupting or reducing usage of key appliances in return for a bill credit or other means of rewarding the customer for taking actions in response to higher wholesale spot market prices. In some cases, regulators will order the mandatory installation and funding for new meters and communication technologies and make permanent changes in how electricity is priced. In general, the overall trend of these initiatives will be to raise electricity prices to pay for the new meters, installation and maintenance of the new meters, new communication facilities, new computers and software to receive and process the information from the meters, and new billing systems to implement the pricing changes. A move to make electricity prices more volatile (i.e., changing more frequently than in the past) and with more difference between “high” prices and “low” prices at different times of day or year would be a major break with longstanding state legislative and regulatory policies to stabilize rates of residential and small business consumers. Most importantly, these initiatives would rely entirely on the wholesale spot market to set the price for basic electricity service for residential customers, thus exacerbating the impact of the administered RTO market design favored by FERC.

Proponents of Advanced or Smart Meters and more volatile pricing programs were able to obtain Congressional support for this approach in the 2005 Energy Policy Act. Buried in Subtitle E of Title XII (Electricity) are several amendments to the Public Utility Regulatory Policies Act of 1978 (PURPA). Sections 1251, 1252, and 1254 of the 2005 Energy Policy Act amend the “Retail Regulatory Policies for Electric Utilities (Title I) of PURPA by adding new federal policies that are applicable to state regulation of electric utilities. Section 1252 contains a

new “smart metering” standard. The standard requires that each electric utility offer to each of its customer classes and to individual customers upon request a “time-based rate schedule under which the rate charged by the electric utility varies during different time periods and reflects the variance, if any, in the utility’s costs of generating and purchasing electricity at the wholesale level.” The time-based schedule “shall enable the electric consumer to manage energy use and cost through advanced metering and communications technology....”

The statute also sets forth the types of time-based rate schedules that may be offered, including “time of use pricing (TOU)” in which prices are broken into two or three time periods and are fixed for some period, but which may change twice per year; “critical peak pricing” (CPP) in which TOU pricing is used except for a few hours per year in which the utility can increase peak prices to a substantially higher level to reflect wholesale market conditions; “real time prices” (RTP) in which prices are provided to the end use customer to reflect the actual or real wholesale market conditions on an hourly or daily basis, typically with a very short notification of forthcoming price changes; and the use of credits for customers with large loads who enter into pre-established peak load reduction agreements that reduce a utility’s planned capacity obligations.

Not content with this mandate, proponents of the “smart grid” and more volatile pricing options included an even stronger federal policy language in the recently adopted Energy Act of 2007. Title XIII, entitled Smart Grid, states, “It is the policy of the United States to support the modernization of the Nation’s electricity transmission and distribution system to maintain a reliable and secure electricity infrastructure that can meet future demand growth and to achieve each of the following, which together characterize a Smart Grid:

- (1) Increased use of digital information and controls technology to improve reliability, security, and efficiency of the electric grid.
- (2) Dynamic optimization of grid operations and resources, with full cyber-security.
- (3) Deployment and integration of distributed resources and generation, including renewable resources.
- (4) Development and incorporation of demand response, demand-side resources, and energy-efficiency resources.
- (5) Deployment of “smart” technologies (real-time, automated, interactive technologies that optimize the physical operation of appliances and consumer devices) for metering, communications concerning grid operations and status, and distribution automation.
- (6) Integration of “smart” appliances and consumer devices.
- (7) Deployment and integration of advanced electricity storage and peak-shaving technologies, including plug-in electric and hybrid electric vehicles, and thermal-storage air conditioning.
- (8) Provision to consumers of timely information and control options.
- (9) Development of standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid.
- (10) Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services

Additional provisions require DOE reports on the implementation of the “smart grid”, the formation of a Smart Grid Task Force that includes FERC, the implementation and funding of regional “smart grid demonstration initiatives”, the development of national standards to support the interoperability of the smart grid, and federal matching funds for smart grid investment costs incurred by utilities. The latter does not carry a specific appropriation amount.

Finally, the 2007 Act also adds two new requirements in amendments to PURPA. The first relates to the state consideration of smart grid investments by:

- requiring utilities that seek investment in “nonadvanced grid technologies” to first demonstrate that qualifying smart grid investments were considered;
- authorizing utilities to recover from ratepayers the capital and operating costs relating to the deployment of smart grid technologies, including a reasonable rate of return; and

- authorizing any utility or other party that deploys a smart grid to recover the remaining book value costs of any equipment rendered obsolete (e.g., the currently deployed mechanical meters) based on the remaining depreciable life of the obsolete equipment.

The second PURPA amendment establishes federal policies to ensure that all electricity “purchasers” are provided with information on prices from their electricity provider concerning “time-based electricity prices in the wholesale electricity market” and “time-based electricity retail prices or rates that are available to the purchasers.” Such information must be offered on a not less than daily basis and must include hourly price and use information, where available, and a day ahead projection of such price information to the extent available. Purchasers must be allowed to obtain access to their own information any time through the Internet, as well as other available means.

Under PURPA the states are not required to adopt these standards. That is, the standards set forth in PURPA do not purport to assert federal jurisdiction over retail electricity prices and price policies. These “federal” standards are written to require the states to “consider” the standards within a certain time period. A state can avoid any new determination entirely if it has already implemented the standard or a comparable standard, if the state regulator has considered the same or comparable standard within the previous three years before enactment, or the state’s legislature has voted on the implementation of the standard or a comparable standard within the previous three years before enactment. The apparent reason for the ultimate deference to the states is that regulation of such matters traditionally is a matter of state concern and has not

been preempted. Indeed, the PURPA requirement that a state must consider the original PURPA agenda adopted in 1978 was narrowly upheld by the Supreme Court in a divided opinion.³³

The result of the new amendments and the PURPA language is that there is now a clear federal standard that supports “smart meters” and the exploration of the new pricing methods that rely on passing through wholesale market spot prices in the form of “time of use” or “critical peak” prices.

Proponents of time-based pricing and smart or advanced meters point to the need to influence how retail customers use electricity, particularly during expensive peak demand periods, as a means to ameliorate the high wholesale market prices that result from the RTO pricing methods. While electricity is more expensive at peak periods under any regulatory regime, the pass through of RTO-administered spot market or hourly prices to end-use customers in restructuring states is likely to have a much more volatile and potentially higher bill impact than relying on the peak period prices that result from traditional cost of service regulatory models.

When generation unit prices and times are averaged, those who need to see the potential for a profit on new merchant power investment may not be paid enough to generate such investment. When a vertically integrated utility sees that it is paying higher prices for running less efficient peakers in more hours, or that capacity reserve margins are shrinking, it may take those price and reliability signals into account and may build new capacity, or take other action to reduce load, through conservation and energy efficiency programs, or shift peak usage through rate design changes. In contrast, most small end users lack power to address a peak price signal

by altering available supply and can only respond by altering demand by changing their time of use, buying more efficient equipment, or reducing absolute consumption.

This economic theory has been used in the context of electric utility regulation for many years, and there are many instances of time of day or seasonally differentiated rates under conventional regulation in states that do not have spot markets. The full import of this approach was muted with traditional regulation in which the utility was allowed to recover the costs of higher priced or more expensive generation and average that price with lower cost generation in its total generation portfolio. However, in jurisdictions where restructuring occurred, many utilities no longer own generation and they rely almost exclusively on short-term wholesale market prices to acquire generation supply for Default Service customers. Regulators are now allowing those wholesale prices to be passed through to retail customers, after transitional retail rate freezes or price caps expire and peak prices now have a significant impact, not only on the cost of peaking power itself, but on all the baseload and intermediate power being sold in peak periods. This increases the interest in sending 'price signals' that can reduce demand for peak period power and its price.

FERC has strongly supported the development of the Smart Grid and the development of demand response programs that rely on time-based prices to stimulate customer reaction to the high price of electricity at those hours. FERC has published two reports on the extent of implementation of advanced or smart meters and the use of time-based pricing options by utilities and has urged the regional markets to create demand response markets that allow retail demand response programs to be bid into the wholesale market to meet capacity obligations at

peak usage times.³⁴ FERC Commissioner Wellinghof is a particularly avid promoter and has testified before Congress³⁵ as follows:

The Commission has taken to heart the Congress's directive to encourage wider deployment of demand response and other advanced transmission technologies. Over just the past eight months, the Commission has taken several steps to develop a platform to support a smart electric grid. For example, in February of this year, the Commission reformed its open access transmission policies to, for the first time, put demand response and other distributed resources on equal footing with other resources in directly contributing to the reliability and efficient operation and expansion of the electric transmission system. The Commission's Order No. 890 provides that demand response and distributed generation may provide a variety of ancillary services when they are capable of doing so. The Commission also found that when such resources are capable of performing needed functions, they should be permitted to participate on a comparable basis in open, transparent transmission planning processes, and that stakeholders should have a forum to come forward with demand response project proposals that they wish to have considered in development of a regional transmission plan.

The Commission has also taken steps to integrate demand response into new mandatory electric reliability standards, the development of which is one of the most important responsibilities that the Congress placed on the Commission in EPAct 2005 (Section 1211). In March, the Commission issued a Final Rule that found that demand response should be allowed to be used to comply with reliability standards governing contingency reserves, reactive power, emergencies, and planning the reliable bulk power system. The Final Rule also makes clear that demand response must be technically capable of providing the function required by a reliability standard. The Electric Reliability Organization (ERO) will develop the process for determining such technical capability through its standards development process.

Last fall, the Commission and the National Association of Regulatory Utility Commissioners (NARUC) jointly launched a Demand Response Collaborative to explore how to better coordinate approaches to demand response policies and practices. The Collaborative has laid a solid foundation in its initial meetings, and I look forward to further discussions this summer. Initiatives are also underway at the Commission and several ISOs and regional transmission organizations (RTO) under our review to integrate demand response into energy and capacity markets. In addition, the Commission is conducting a series of conferences to examine the state of competition in wholesale electric markets and to explore the role of demand response in those markets. The Commission is also developing a plan for a new staff unit that will focus on demand response in order to create additional expertise within the Commission on such innovative technologies.

On a related matter, the Congress directed the Commission in Section 1241 of EPAct 2005 to provide incentives for transmission investment that promotes reliable and economically efficient transmission and generation of electricity and to encourage deployment of transmission technologies and other measures to increase the capacity and efficiency of existing transmission facilities. In its rule implementing that directive, the Commission highlighted the importance of investment in economically and technologically efficient transmission infrastructure. I have emphasized in a number of subsequent cases that the Commission should target incentives that increase an applicant's return on equity to investments that provide incremental benefits, such as gains that result from the deployment of best available technologies that increase operational and energy efficiency. Targeting incentives in this manner would encourage the deployment of smart grid technologies.

Thus, the Commission is moving forward in developing a regulatory framework to enable an efficiently designed, smart electric grid. It is my hope that States will examine how their consumers can benefit most

from that framework, including the opportunities for demand response to participate in wholesale electric markets.

There is much more work to do, however, if we are to achieve the full potential of a smart electric grid. For example, widespread deployment of advanced metering technology will empower more consumers to take advantage of opportunities that are available for demand response in the wholesale electric markets under the Commission's jurisdiction. It is my understanding that other witnesses will discuss in greater detail the provisions of EAct 2005 that address advanced meters, including provisions related to the responsibilities of State regulatory authorities. I would like to highlight briefly an August 2006 report that the Commission's Staff prepared in response to a directive in Section 1252(e)(3) of EAct 2005. In preparing that report, the Commission's Staff developed a comprehensive national survey on demand response and advanced metering. The report concludes that demand response has an important role to play in both wholesale and retail electric markets, and that the potential immediate reduction in peak electric demand that could be achieved from existing demand response resources is between 3 and 7 percent of peak electric demand in most regions. Unfortunately, the report also found that technologies such as advanced metering that are needed to support significant deployment of demand response resources have little market penetration.

I agree with the conclusion reached by the Commission's Staff that demand response has an important role to play in both wholesale and retail electric markets. I also see that conclusion as reinforcing the need for coordination of federal and state approaches to this issue. The Demand Response Collaborative launched by the Commission and NARUC marks a promising step toward that goal. It also would be valuable to more formally establish this coordination. I encourage the Congress to establish a federal-state working group through which the Commission and interested state representatives would be tasked with identifying best practices and developing consistent standards for demand response.

V. A NOTE ABOUT PUBLIC PARTICIPATION AT FERC

FERC is a regulatory agency that operates subject to the directives of Congress and the policy positions of the President who appoints the Commissioners, particularly the Chair. Unlike most state regulators, however, there is no publicly funded consumer advocate that represents the views of customers, either retail or wholesale customers. Instead, FERC's actions are dominated by well-funded attorneys and experts hired to represent the views of public utilities, owners of generation facilities, the RTO bureaucracy (note that PJM has over 400 employees), large commercial and industrial customers, owners of transmission facilities, and advocacy groups formed to represent the views of these and other wholesale market "actors" on a particular issue. While FERC's website offers a section entitled "FERC For Citizens," it is entirely directed to educating consumers about specific hydropower or natural gas pipeline projects, the siting of which FERC has authority to approve or disapprove. This area has also been recently upgraded to reflect FERC's role in the siting of LNG natural gas pipeline facilities and electric transmission facilities. These areas, while important, are not nearly as impactful on customer prices for essential utility services as FERC's policies and rulemakings concerning wholesale electric and natural gas competition, market structure, RTO formation, market power oversight investigations³⁶, enforcement of "market based" pricing rules, and enforcement of new reliability standards.

If a consumer or organization seeks to intervene in a major policy proceeding at FERC, they are advised as follows by the FERC website:

DECIDING WHETHER TO INTERVENE IN A PROCEEDING

Want to appeal FERC decision in court? - YES

- Look up [docket number](#)
- Look a number of intervenors on [service list](#) (*NOTE: Once FERC accepts a motion to intervene, the Intervenor must provide a copy of all subsequent correspondence with FERC to everyone on the service list)

Still want to intervene? - YES

- Prepare motion to intervene
- [eFile](#) or send motion to FERC
- Receive project correspondence by mail

Want to appeal FERC decision in court? - NO

- [eFile](#) or send comment or protest to FERC

Want copies of all project correspondence sent by eMail? - YES

- Use [eSubscription](#)
NOTE: Intervenors may also use [eSubscription](#)

While the actual filing of the documents may not be difficult, the real barrier arises with respect to the length, complexity, and scope of the actual participation in a controversial proceeding that may result in significant impacts on retail customer prices. For example, ISO New England filed a proposed new program to assure sufficient long term capacity resources with FERC in March 2004.³⁷ The docket sheet for this filing and the litigation that surrounded it consumed three years and it required 217 pages just to list the docket entries for this proceeding, including the testimony, motions, orders, and other documents that are part of FERC's official record.

As a result, the most important policy issues are made without any regular appearance by representatives of residential customers. Of course, FERC does not have any formal jurisdiction over retail sales or the prices charged by public utilities regulated by state authorities. However, as this analysis suggests, the market structure and policies promoted by FERC have had a

dramatic impact on residential prices for electricity in those states that have adopted retail competition or restructuring. The lack of any voice for these customers on a regular basis and funded sufficiently to provide expert input and analysis is disturbing. While the state public utility advocates or NASUCA on occasion submits comments to FERC and, in some cases, appears in formal hearings on some matters, these state consumer advocate offices are typically insufficiently funded to provide a regular and high level presence at FERC and many of them are barely able to fund their activities before their state regulator and cannot take on any additional tasks relating to federal activities.

VI. CONCLUSIONS AND OBSERVATIONS

It is not the purpose of this paper to determine whether FERC's policies and the manner in which it has implemented the creation of the regional energy markets have harmed residential consumers or whether they have assured the lowest prices compared to more traditional regulatory policies that rely on actual costs and analysis of reasonable rates of return. Other commenters have strongly criticized FERC's policies, the RTO market structure, and the lack of sufficient oversight and enforcement of potential market power. However, it is fair to conclude that FERC's policies and the operation of the current structure of the wholesale market for the sale of electricity, coupled with state adoption of restructuring, has resulted in the following observations and trends:

- There has been a clear and dramatic loss of state control over prices charged by generation facilities for electricity in states that have restructured because these generation supply units are no longer "owned" by the local public utility. As a result, the power sold by the generators is no longer based on actual costs, but a reflection to a substantial degree of the RTO method of pricing short-term electricity sales in which the highest bidder sets the price for all generation needed to serve load in a particular hour or time of day. The older generation units that were paid for by local ratepayers are now able to obtain prices for their generation supply that do not reflect actual costs, but are strongly influenced by the structure of the RTO-run markets. This market structure is not based on a statutory directive, but FERC's policies and is obviously strongly supported by the beneficiaries of this pricing method at this time.

- When states adopted restructuring, the statutory directive was typically to ensure that the future price of electricity sold to consumers would reflect a competitive market price because state policymakers assumed that the introduction of competition would result in lower prices compared to traditional regulation and that new generation would be built and offered for sale to retail customers at prices lower than the expensive nuclear power and other facilities that contributed to the move to restructuring in the first place. Therefore, state policymakers have typically emphasized the importance of relying on generation supply obtained through competitive means in the wholesale market for provide service to retail customers. Most state Default Service policies have emphasized relatively short term (1 to 3 years) contracts in which the successful bidder provides all the necessary energy, balances the supply and demand, and otherwise assume responsibility for assuring that the electricity flows to the utility's customers. The prices for these contracts have reflected the regional wholesale market structure and pricing policies so that these retail prices have starkly reflected market volatility, the rise in natural gas prices, and the emphasis on short term market trends. Default service prices are no longer a reflection of a diverse portfolio of generation supply units and price structures that were based on long term investment under traditional regulation.
- State energy prices for Default Supply obtained in this manner have reflected a total reliance on generation supply and have destroyed the link between generation supply and energy efficiency and demand response analysis and resources. It is only recently that the states have realized this significant defect and turned to the stimulation of energy efficiency programs to incorporate the potential for “negawatts” in the pricing of

electricity and the control of long term demand. FERC also has realized this defect in its current market structures and has now favored the ability of demand response resources in particular to be bid into longer term capacity market auctions operated by the RTOs.

- When the utilities divested their generation supply resources, most states also assumed that the “market” would cause the necessary level of investment in new generation to assure long term reliability of supply. This did not occur. As a result, RTOs and other regional organizations under FERC control have taken over the role of long term planning and assurance of reliability of service and developed highly controversial new regional capacity markets that are designed to significantly increase electricity prices in areas that need new investment in generation.
- Finally, FERC’s policies and the structure of the regional electricity markets have relied on spot markets and hourly prices to send the signal about the need for and cost associated to provide new generation facilities, as well as the need to encourage the development of demand response programs as a substitute for new generation. This approach to assuring long term reliability of supply and new investment in generation has contributed to more emphasis on transmitting more volatile pricing schemes to residential customers so that the customers have the responsibility to shift usage or reduce usage in order to obtain a potentially lower bill. This approach, while not unique to restructuring states, has a more dramatic impact on customers in restructuring states due to the RTO-administered wholesale market and its emphasis on spot market prices. The culmination of this approach is reflected in the FERC support for the Smart Grid that would require investment in Advanced Metering and the use of time-based prices that pass through

wholesale market spot prices to residential customers to obtain demand response and reduce peak demand.

BIBLIOGRAPHY FOR FURTHER READING

The following references will allow the reader to explore in more detail the issues and policies discussed in this paper:

An excellent history of federal regulation of energy prices and the growth of FERC's jurisdiction:

Cudahy and Henderson, *From Insull to Enron: Corporate (re) Regulation after the Rise and Fall of Two Energy Icons*, Energy Law Journal, 26 Energy L.J. 35 (2005).

The American Public Power Association has sponsored a number of studies to examine electricity market reforms. The summary of these studies is available at www.appanet.org. APPA has concluded that "On balance, electricity consumers are not benefiting from restructured wholesale markets in regions of the country serviced by FERC approved regional transmission organizations (RTOs) or independent system operators (ISOs)."

Kwoka, J. *Restructuring the U.S. Electric Power Sector: A Review of Recent Studies* (2006)

APPA, *Consumers in Peril: Why RTO-Run Markets Fail to Product Just and Reasonable Prices* (February 2008)

Dr. Kenneth Rose, an economist, has published widely on national analyses of both retail and wholesale prices under restructuring.

Rose, K. and Meeusen, K., 2006 Performance Review of Electric Power Markets Part I: Status of the Development of Regional Competitive Markets: Performance Review of Electric Power Markets. Virginia State Corporation Commission. 2006. Available at http://www.scc.virginia.gov/caseinfo/reports/2006_rose_1.pdf

Rose, K. *The Impact of Fuel Costs on Electric Power Prices*. 2007. Available at <https://www.appanet.org/files/PDFs/ImpactofFuelCostsonElectricPowerPrices.pdf>

Power in the Public Interest has published several reports on the impacts of restructuring and RTO-market prices on retail customers. They have charts showing "before" and "after" prices for all restructuring states. See www.ppinet.org

Synapse Energy Economics has published a number of papers on portfolio management for Default Electricity Supply, all of which are available at www.synapse-energy.com :

Best Practices in Procurement of Basic Electric Service for Residential and Small C&I Customers (2004)

Portfolio Management: Tools and Practices for Regulators (Prepared for NARUC 2006)

Integrated Portfolio Management in a Restructured Supply Market (Prepared for Ohio Consumers' Counsel 2006)

Barbara Alexander's publications that are relevant to this paper include:

Smart Meters, Real Time Pricing, and Demand Response Programs: Implications For Low Income Electric Customers (May 2007), available at:

http://www.pulp.tc/Smart_Meter_Paper_B_Alexander_May_30_2007.pdf

Red Flags for Consumer Protection Policies Governing Essential Electric and Gas Utility Services: How to Avoid Adverse Impacts on Low-Income Consumers (October 2005).

"Managing Default Service To Provide Consumer Benefits In Restructured States: Avoiding Short-Term Price Volatility" (National Center for Appropriate Technology, June 2003).

Available at: <http://neaap.ncat.org/experts/defservintro.htm>

The Impact of Utility Retail Competition on Low-Income Consumers in Texas, Massachusetts, Georgia, New York and Ohio. (National Center for Appropriate Technology, December 2003).

Available at: <http://neaap.ncat.org/experts/index.htm>

Default Service: Can Residential And Low Income Customers Be Protected When The Experiment Goes Awry? An Update to the April 2001 Report (October 2001). Available at:

<http://liheap.ncat.org/pubs/defaultupdate.doc>

Direct, Rebuttal and Surrebuttal Testimony on behalf of Pennsylvania Office of Consumer Advocate before the Pennsylvania PUC, Petition of West Penn Power d/b/a Allegheny Power for Approval of its Retail Default Service Program, Docket No. P-00072342 (February-March 2008)

Direct and Rebuttal Testimony on behalf of the Maryland Office of People's Counsel before the Maryland PSC, In The Matter of the Optimal Structure of the Electric Industry of Maryland, Case No. 9063 (October and November 2006).

Recently adopted restructuring reform legislation can be obtained from the individual state legislative websites:

Montana's repeal of retail competition: <http://data.opi.mt.gov/bills/2007/billpdf/HB0025.pdf>

Virginia's repeal of retail competition: <http://leg1.state.va.us/cgi-bin/legp504.exe?071+ful+CHAP0888>

Delaware's restructuring reform law (Title 26, Section 1007):

<http://delcode.delaware.gov/title26/c010/index.shtml>

Connecticut's restructuring reform legislation: <http://www.cga.ct.gov/2007/ACT/PA/2007PA-00242-R00HB-07432-PA.htm>

Electric Bills Zap Mainers

Bangor Daily News (November 22, 2007)
Tom Walsh

BANGOR — If you think your electric bill is already too high, Carroll Lee has some bad news: The worst is yet to come.

“Electric rates in Maine are now 59 percent higher than the U.S. average, an annual penalty of \$700 million, the equivalent to 25 percent of our state tax collections,” the former Bangor Hydro-Electric Co. executive said in a speech last week to the Rotary Club of Bangor. “It will soon get even worse.”

Lee was the utility’s president and chief operating officer during the last five of his 32 years at Bangor Hydro. From his home in Brewer, he now works as an energy and business consultant. For more than 10 years, Lee has been a vocal opponent of de-regulation of the electrical utility industry in Maine.

In hopes of lowering consumer costs for electricity through increased competition, Maine’s Electric Utility Restructuring Act of 1997 required Bangor Hydro and other electrical utilities throughout Maine to get out of the business of generating the electricity they distribute.

When he signed the new law in 1997, Governor Angus King Jr. predicted “consumers will see lower electricity rates in the foreseeable future.”

That never happened. Instead, in the seven years between March 2000, when restructuring regulations took effect, and March 2007, the cost of generating electricity for households in Downeast Maine doubled. In his talk, Lee reviewed the complex mix of economic and political factors that continue to drive up the price of electricity for all but Maine’s largest industrial consumers.

Among them is “marginal pricing,” an auction-based approach to setting wholesale electricity prices. It’s a free-market mechanism that Maine Public Utilities Commission Chairman Kurt Adams agrees is “killing consumers.”

“An early response to the new law was the construction of several large, non-utility, natural gas-fueled generators,” Lee said. “Under deregulation, gas generation was the only significant supply added, and gas set the market clearing price most of the time.

“While regulation recovered only average supply costs, deregulation allows recovery of the market clearing price, which is much higher. All generation gets the clearing price — hydro,

coal, nuke, all. It doesn't matter what the cost is; they all get it. [Natural] gas prices doubled, so all power supply prices doubled."

Lee predicts a new state law that boosts renewable-fuel generation requirements from 30 percent to 40 percent will cost consumers \$65 million annually. He also expects Maine's decision to join the Regional Greenhouse Gas Initiative will cost \$30 million a year. Federal efforts to remove the Veazie, Great Works and Howland hydroelectric dams on the Penobscot River could prove costly, too.

"This will cost \$50 million, initially — tax money, most of it — and eliminate future hydro benefits many times more," he said. "In the context of \$3-a-gallon heating oil, this does not compute for me, even accounting for purported public benefits."

Lee would like to see Maine return to regulation and revert to the system where utilities operated as tightly regulated monopolies that can own and generate the electricity they deliver to consumers.

"Most of the U.S. has not forced power supply competition," he said. "They continue with regulated electric utilities, with captive customers enjoying relatively low electric costs, which don't vary with gas prices.

"California's experiment with deregulation ended with disaster, and they've gone back to regulated supplies. Other states are doing the same. Governor Baldacci, in his weekly radio address on Aug. 25, noted 'high electricity costs today are caused by electricity deregulation that hasn't worked out as promised.'"

Lee is delighted that the Legislature recently ordered the Maine Public Utility Commission to evaluate the option of re-regulation. He's also an advocate of nuclear power. "As part of the plan to re-regulate, Maine should support the construction of a new nuclear power plant to directly benefit Maine customers," he said. Maine's only nuclear power plant — Maine Yankee in Wiscasset — was closed in 1997 as the state embraced deregulation. "During its 25-year life, it provided 40 percent of Maine's electric needs," he said. "It saved consumers about \$5 billion, returning its \$250 million initial investment many times, probably the most successful enterprise in Maine's history."

END NOTES:

¹ This paper will not focus on the Texas restructuring model because it is unique in that distribution utilities were eliminated from any retail relationship with customers and all customers are required to obtain electricity from a Retail Electricity Provider who bills and collects for the distribution service (purchased from the utility by the REP) and generation supply service. Furthermore, most of Texas is not subject to FERC jurisdiction because historically its major transmission system did not interconnect with other states. As a result, the Texas wholesale market is regulated by the State of Texas.

² While FERC had adopted Order 888 in 1996 to encourage the development of independent system operators of the bulk power system and to require more access to the transmission system for the newly independent generating facilities that were beginning to arise, the development of wholesale market pricing structures that have developed under Regional Transmission Organizations or RTOs did not occur until after the adoption of restructuring legislation in most states. PJM's RTO application was approved by FERC in 2001. PJM's regional capacity market was not approved by FERC until 2006.

³ While referred to by different names (e.g., Provider of Last Resort, Standard Offer Service, Basic Service), this paper will use the term Default Service to refer to generation supply service that is provided by the local utility to those customers who have not selected an alternative supplier.

⁴ In most states, the local utility signed a contract with their generation affiliate to provide this service during the term of the rate cap or rate freeze as a condition of the transfer of the asset from the vertically integrated utility to an affiliate or to an independent owner of the generation facility.

⁵ The retail marketers testify in most states that the reason that they cannot make offers to residential customers is due to either the existence of the rate caps (i.e., the marketer cannot beat this price) or the fact that Default Service is provided under fixed price wholesale market contracts (i.e., the price is not volatile enough to allow marketers to offer stable price options to residential customers). These debates can be viewed in the Maryland Public Service Commission's Case No. 9111 in which the Commission is considering the policies and purchasing guidelines that should be applicable to Default Service. The Commission's website contains the filings by all the parties to the proceeding at www.psc.state.md.us/psc

⁶ McCullough, Howard, and Deen, "The High Cost of Restructuring," *Public Utilities Fortnightly* (February 2008), at 55-58, 55. The author uses the term "administered markets" to refer to Regional Transmission Organizations. Other studies have recently been published that allege the same results, e.g., Blumsack, Lave, and Apt, "Electricity Prices and Costs Under Regulation and Restructuring" (Carnegie Mellon Electricity Industry Center Working Paper CEIC-08-03, available from the CEIC website: www.cmu.edu/electricity and "Retail Electric Rates in Deregulated and Regulated State: A Ten-Year Comparison", published by the American Public Power Association (March 2008), available at www.appanet.org

⁷ Among the wholesale and retail suppliers that declared bankruptcy after 2000 were Enron, Mirant, NRG, and Calpine.

⁸ 16 U.S.C. §824d [Federal Power Act]

⁹ 15 U.S.C. §717c [Natural Gas Act]

¹⁰ Pub. L. No. 95-617, 92 Stat. 3117 (1978).

¹¹ Pub. L. No. 95-621, 92 Stat. 3350 (1978).

¹² Pub. L. No.102-486.

¹³ FERC, Order 888, Promoting Wholesale Competition through Open Access Non-Discriminatory Transmission Service by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, adopted in 1996, codified at 18 C.F.R. pts 35, 385.

¹⁴ See Revised Public Utility Filing Requirements, 67 Fed. Reg. 31,043, 31,047-48, May 8, 2002.

¹⁵ Pub. L. No. 109-58.

¹⁶ Pub. L 110-140, signed December 19, 2007. This Act adopts new vehicle fuel economy standards, additional subsidies for biofuel production, stricter national energy efficiency standards for certain appliances, federal energy reduction goals for federal buildings, grants and loans for energy efficiency initiatives at the state level, research and development funding for solar energy and other renewable energy resources, as well as various tax and other incentives for traditional fuels.

¹⁷ FERC's Order 888 established the basic policies governing Open Access Tariffs for transmission service and recent rule revisions continue this path. See Preventing Undue Discrimination and Preference in Transmission Service, Order 890 (February 16, 2007) and Order 890A (Order on Reconsideration, December 28, 2007).

¹⁸ Market-Based Rates For Wholesale Sales Of Electric Energy, Capacity And Ancillary Services By Public Utilities, Order 697, June 21, 2007.

¹⁹ PJM Interconnection, L.L.C., et al., Order Provisionally Granting RTO Status, Docket No. RTO1-2-000 (July 12, 2001), 95 FERC ¶ 61,___ (2001).

²⁰ *Lockyer, et.al.v. FERC, et al.*, 383 F.3rd 1006 (9th Cir. 2004), *cert. denied*, 127 S.Ct. 2972 (2007).

²¹ Statement of Chairman Joseph Kelliher (FERC) on adoption of Order No. 697, June 21, 2007.

²² *Morgan Stanley Capital Group, Inc. v. P.U.D. No 1 of Snohomish County, Washington, et. al, cert. granted*, ___U.S.___, 128 S. Ct. 30 (2007). This case raises similar questions concerning the filed rate doctrine and the scope of FERC's review of wholesale market contracts.

²³ Regional Transmission Organizations, Order No. 2000, 65 Fed. Reg. 809 (January 6, 2000), FERC Stats. & Regs. ¶ 31,089 (1999), order on reh'g, Order No. 2000-A, 65 Fed. Reg. 12,088 (March 8, 2000), FERC Stats. & Regs. ¶ 31,092 (2000), petitions for review pending sub nom., Public Utility District No. 1 of Snohomish County, Washington v. FERC, Nos. 00-1174, et al. (D.C. Cir).

²⁴ FERC News Release, July 31, 2002, Docket No. RM01-12-000, "Commission Proposes New Foundation for Bulk Power Markets with Clear, Standardized Rules and Vigilant Oversight."

²⁵ The Texas state jurisdiction over the bulk of the transmission assets in Texas reflects an historical anomaly in which the transmission lines have been deliberately prevented from interconnecting with other states, thus avoid "federal" jurisdiction.

²⁶ For example, the largest generation supplier that won the right to provide electricity to residential and small commercial customers in Maryland is Constellation Energy who now owns the power plants that used to be subject

to state regulation because they were owned by Baltimore Gas & Electric. The same is true in Illinois where Exelon won the right to provide power under the Default Service auctions with generating facilities that were subject to state control as public utilities when owned by Commonwealth Edison. In Maine, Central Maine Power Co. sold its low cost hydro facilities to Florida Power & Light who now bids to provide Default Service to CMP's residential customers.

²⁷ This chart can be accessed from PPI at: www.ppinet.org. It should be noted that Pennsylvania is not included as 'deregulated' state in this chart because most larger utilities in that state still provide service under rate caps and so their customers have not been exposed to "market" prices.

²⁸ The Bibliography attached to this paper lists some of the more prominent studies. Of course, other studies, most of which funded by or promoted by owners of the FERC-regulated wholesale suppliers, claim that other factors explain these price results.

²⁹ The experience in **Maryland** is typical. The average residential total bill in Maryland increased by over 70% in January 2007 as a result of moving from capped rates to market rates that reflected fixed price full requirements wholesale market contracts. According to customer migration data published by the Maryland PSC, as of January 2008, 2.4% of Baltimore Gas and Electric's residential customers were served by an electric supplier. See <http://webapp.psc.state.md.us/Intranet/samplecode/enrollmentrpt.cfm>. The Maryland Office of Public Counsel also prepares a chart that compares current supplier offers and the utility price to compare. The most recent chart in February 2008 states that every offer being made to residential customers by the active suppliers in the BGE area reflects a price that is higher than the current BGE price and several of those listed as "active" on the PSC website are in fact not currently making offers to residential customers. Many of the supplier offers are only for renewable power or longer term fixed price service. Most of them also require a hefty termination fee of \$75 or more. See <http://www.opc.state.md.us/assets/documents/Electric%20Supplier%20Prices%20and%20addresses%20020108.pdf> In **Maine** there are no retail marketers making offers to residential customers except the occasional "green" supplier. Even though residential customers served by **Connecticut** Light and Power pay over 11 cents per kWh for generation supply service from their incumbent utility, there are only four suppliers listed on the Connecticut Commission's website as making offers to such customers, but one of them declares on its website that they are no longer serving residential customers. Another of the four marketers does not state any pricing information on its website for CL&P residential customers.

³⁰ . The District of Columbia Public Service Commission recently announced that Pepco's recent bid results for full requirements contracts will result in a generation supply price of 11.3 cents per kWh for residential customers starting in March 2008. BG&E residential customers in Maryland also pay 11.3 cents per kWh. This result is not limited to PJM-states. Massachusetts and Connecticut residential customers also pay over 11 cents per kWh for generation supply service, reflecting the winning bids for full requirements contracts.

³¹ E.g., New York, Maine, Massachusetts, Connecticut, and Illinois.

³² Analysis Of Options For Maryland's Energy Future, Prepared By Kaye Scholer LLP, Levitan & Associates, Inc. and Semcas Consulting Associates, for the Maryland Public Service Commission, November 30, 2007, page 49. This report is available on the PSC's website: www.psc.state.md.us

³³ *FERC v. Mississippi*, 456 U.S. 742 (1982) <http://caselaw.lp.findlaw.com/cgi-bin/getcase.pl?court=US&vol=456&invol=742> In dissent, supported by three other justices, Justice O'Connor stated: "The power to make decisions and set policy, however, embraces more than the ultimate authority to enact laws; it also includes the power to decide which proposals are most worthy of consideration, the order in which they should be taken up, and the precise form in which they should be debated. PURPA intrudes upon all of these functions. It chooses 12 proposals, forcing their consideration even if the state agency deems other ideas more

worthy of immediate attention. In addition, PURPA hinders the agency's ability to schedule consideration of the federal standards. ...Finally, PURPA specifies, with exacting detail, the content of the standards that will absorb the agency's time." Subsequent opinions and changes in court composition since 1982 cast significant doubt on the vitality of *Mississippi v. FERC*.

³⁴ FERC has established a Smart Grid Collaborative with the National Association of State Utility Regulatory Commissions (NARUC) to have a "dialogue on facilitating the transition to a smart electric grid." See <http://smartgrid.webexworkspace.com> . FERC's 2006 and 2007 Reports on Advanced Metering and Demand Response can be accessed at: <http://www.ferc.gov/industries/electric/indus-act/demand-response/dem-res-adv-metering.asp>

³⁵ Prepared Testimony of Jon Wellinohoff, Commissioner, Federal Energy Regulatory Commission, Before the House Energy and Commerce Subcommittee on Energy and Air Quality, May 3, 2007. This testimony is highlighted on the FERC website devoted to Demand Response and Advanced Metering referenced in fn. 32.

³⁶ This website does offer the public the means to "complain or report market activities or transactions that may be an abuse of market power, an abuse of an affiliate relationship, a tariff violation, or other possible violation or concern" through an Enforcement Hotline through a toll-free number. Such reports or complaints can be made anonymously. See <http://www.ferc.gov/contact-us/enforce-hot.asp> However, it is fair to ask whether any residential customer or even a statutory representative of residential customers could pierce the complex veil that surrounds the pricing methods promoted by RTO-run markets and the lack of transparency concerning how these prices are established or monitored.

³⁷ FERC Docket No.ER03-563-030.