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Decoding Developments in Today's Electric Industry — Ten Points in the Prism

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HIGH ELECTRICITY PRICES, HIGH ANXIETY

Electricity prices have been rising around the U.S. in recent years. Almost no part of the country has been spared. In some regions, rates have gone up gradually over the past decade. In other regions, prices are sharply up over a shorter period of time. Everyone knows about the most famous and painful example: California during the days of the 2000/2001 electricity crisis. But sudden price increases have popped up elsewhere, too — like Maryland and Illinois, and other places where multi-year electricity rate freezes have ended and where electricity consumers have begun to face prices that are no longer sheltered from actual market conditions. Even consumers in traditionally regulated states like Florida, Arkansas, Louisiana and Hawaii experienced relatively large electricity price increases across the past few years.[1] The sudden price increases have put pressure on household and business budgets around the country. This, in turn, has grabbed the attention of the media, provoked politicians, and generally led to finger-pointing and demands for explanations of who or what is to blame.

There's nothing fun about any of this. No consumer likes price increases of any kind, let alone those we feel we can't control and that we figure must be caused by someone else's mischief. There's something especially grating about electricity price increases, it seems. Maybe it's because we bought into Thomas Edison's promise that "I shall make electricity so cheap that only the rich can afford to burn candles." Perhaps it's because our society has such a deep dependency on electricity, not just for basic necessities like light and cooling, but for all of the wonderful devices and gadgets it powers. Maybe it's because electricity is just "invisible": it simply exists very dependably in the sockets in our homes and offices whenever we plug in, and we don't think twice about it (until, of course, the bill arrives).

For most Americans, in fact, electricity is out of sight, out of mind. We know it's there, but there's nothing really to see. Electricity "brings good things to light," and it's the things we see, not the electricity itself. We live our lives and go about our business without making — let alone, understanding — any sort of connection between the light switch, the new gadgets plugged into the socket, and the pressure we put on electricity suppliers to meet our on-the-spot power requirements with near-perfect reliability. The sheer "invisibility" of electricity makes it all the harder to understand why it costs so much. If electricity is already in the wall, why is the price going up? What does your new phone charger have to do with power plants and the price of natural gas?

This isn't to say that consumers are to blame for price increases. They're not. Nor is "the system" to blame, although occasionally we can find some genuine villains along the way. Perhaps some small portion of the blame should be attached to the specific social paradigm in which we accept electricity as just "being there."

The power is there in the wall. We don't really know (or care) where it comes from, as long as it behaves. When it doesn't, we assume that someone somewhere must be doing something wrong, since we didn't. We simply take it for granted that the invisible and wonderful but utterly boring electricity will be there — and that when price increases occur, there must be something wrong in the system that needs to be fixed.

Taking something for granted until prices rise isn't unique to electricity, of course. We don't pay attention to something until it disappoints. It's human nature. When something goes wrong, we assume we can "fix" it, so we try to "do something." This seems true in many markets, but the threshold for our interventionist tendencies seems particularly low where electricity is concerned due in part to its history as a regulated industry. Our traditional regulatory paradigm gives us a predisposition to intervene when the opportunity arises. While the instinct to intervene when prices increase may be an understandable one, it needs to be tempered with a degree of humility about the real opportunities to improve market performance and prices in the face of economic realities. And because we have just undergone a restructuring of the electric industry in many parts of the country,[2] there is a natural inclination to consider the potential link between these changes and the price increases we've been experiencing.

DECODING TODAY'S ELECTRIC PRICES — LOOKING THROUGH A COMPLEX PRISM

So, what *is* happening in the electric industry? And what should — and can — be done about it? There are no satisfyingly simple answers to these questions, but there is some light we can shed on the situation. Let's start with an even "top ten" issues, described in this paper. These ten facets of the prism reveal an industry that continues to provide significant value to the economy and to consumers, even as prices seem to be rising — everywhere.

These facets also suggest that relatively high electricity prices are likely to be the "new normal" in the electric industry, and this is likely to occur for consumers served in regions with vertically integrated electric utilities under cost-based regulation, or in ones relying substantially on markets. This reality stems from fundamental economic forces tied to global markets for fossil fuels and other products, and the need to address other critical economic and social challenges such as continued demand for power, aging infrastructure and global warming. Even so, and presuming a degree of regulatory and policy stability going forward and reliance to a considerable degree on market forces, we can expect private investors to supply capital for the grid, for greater improvements in energy efficiency and in power production facilities. We can look forward to an electric sector producing lower pollution levels than in the past. All of this is good for consumers.

Part of helping consumers realize these benefits will be for government officials to adopt policies giving consumers the tools they need — improved information, pricing signals and service provisions that overcome the "invisibility" inherent in today's electricity system. Many of these, in turn, are aided by competitive elements in the industry that allow for real-time pricing, innovation and a focus on customers. Part of helping consumers is also applying care when adopting "fixes," so that the cure doesn't end up being worse than the disease. For an industry as complex as the electric industry, it seems particularly prudent to allow further evolution in the paths being taken in different parts of the country. This kind of regulatory stability — in the regions with vertically-integrated utilities, and in the regions relying on increasingly robust competitive industry structures — will go a long way to providing the environment that will support our shared goals for an efficient, reliable and environmentally acceptable electricity system.

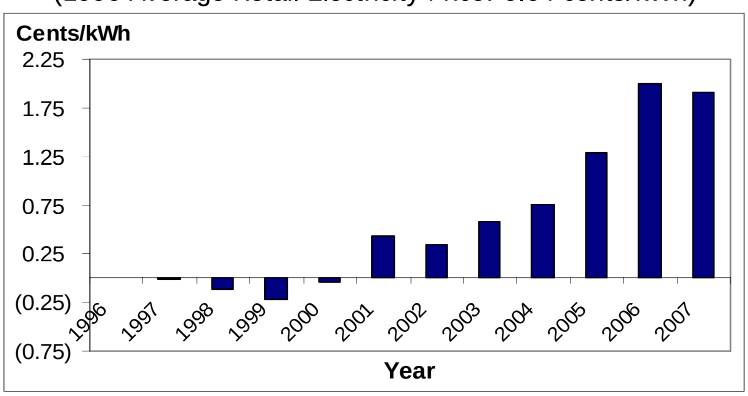
1. "ELECTRICITY IS NOT TOO CHEAP TO METER."

This may seem too obvious to even mention. But just because we now scoff at Lewis Strauss' vision made fifty years ago — that "*our children will enjoy in their homes electrical energy too cheap to meter"* — doesn't mean that we have really embraced today's situation, that electricity is not cheap to produce and deliver to consumers. Consumers still take for granted that they'll get reliable electricity at low rates. And there's hardly a politician around the country who doesn't hold on to the dream of lowering the cost of electricity for their consumers.

This continuing view — that electricity should be cheap, and that there's someone to blame when it's not — is not reality-based. That's not to say that there are never instances where someone is to blame when prices spike; there are. This can occur where a utility takes advantage of its position to benefit its affiliate or to shift cost overruns on to consumers; or where a power plant owner or power trader actually manipulates electricity markets. But it is another thing altogether to presume that high prices equate to market manipulation or the exercise of market power.

Like energy prices in general, electricity prices seem high. With prices at around 6.6 cents per kilowatt-hour ("kWh") in 1996, the average American has seen prices go up approximately a third over the past decade (although there were decreases in prices during the late 1990s). (See Figure 1.)

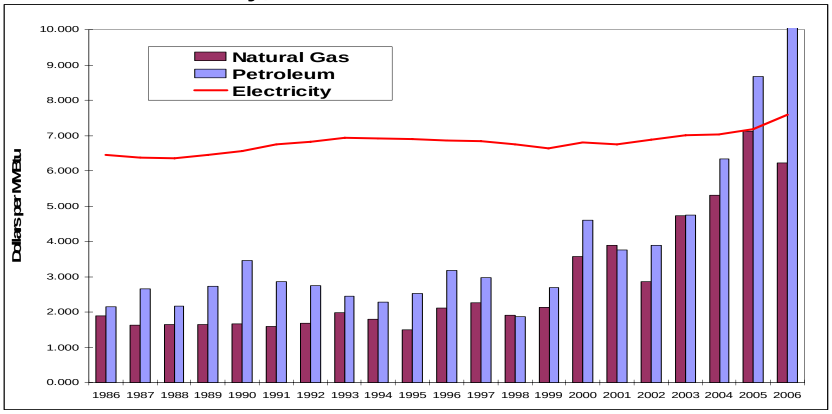
Figure 1
U.S. Retail Electricity Prices:
Difference in Average Annual Electricity Prices Relative to Prices in 1996
(1996 Average Retail Electricity Price: 6.64 cents/kWh)



Source: U.S. Energy Information Administration ("EIA"), with prices through April 2007[3]

Electricity prices have been rising for several reasons. First, the price of the fuels used to produce power has climbed in recent years. The single most expensive part of the electrical bill is tied to power production costs including purchased fuel. Fossil fuels — used to produce just over 70 percent of the nation's power[4] — have experienced significant price increases in the past few years after a period of comparative calm during the 1990s. The most dramatic increases have been for natural gas and petroleum (see Figure 2) which account for approximately one-fifth of the nation's power generation. Electricity prices tend to track changes in fossil fuel prices over time, with prices beginning to rise starting around 2000.[5]

Figure 2
Prices of Electricity, Natural Gas and Petroleum — 1987-2006



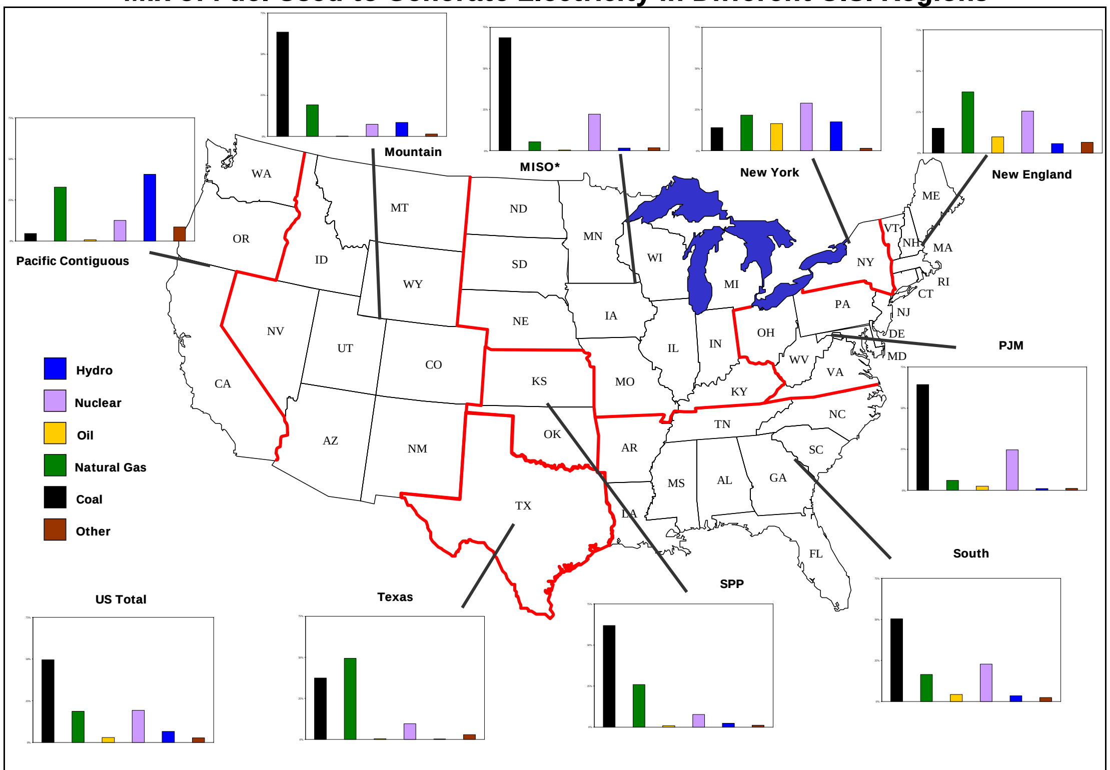
Source: EIA, Electric Power Annual, 2005 (2006), Figure ES-3.

Most Americans understand that oil prices are high, because gasoline prices are so visible at the pump. While not much oil is consumed to produce power, oil is still often used to produce power during peak demand periods and thus tends to influence electricity prices at certain times of year. More importantly for electricity, after a decade of relative calm prices for natural gas during the 1990s, natural gas prices shot up starting in late 1999, as the markets tightened in North America. While natural gas prices spiked following the Hurricanes of 2005, they have dropped since then, although they remain relatively high. Even coal — the lowest-cost fossil fuel, and the fuel used to produce over half of the power generated in the U.S. — has experienced 40-percent price increases since 2000.[6]

Of course, these fuel-cost-related impacts on electricity prices vary dramatically across the country because of sharp regional differences in the fuels used to generate power. As shown in Figure 3 (which indicates each region's reliance on different fuels to produce electricity), some regions (like New England, California, and Texas) that rely significantly on natural gas to produce power have relatively high electricity prices (as shown in Figure 4). States in parts of the country (such as the South, the Mountain states, and the Midwest) that produce more than 50 percent of their power from coal have among the lowest electricity rates in the country. Of the 30 states with rates below the average state electricity rate in 2006 (as shown in Figure 4), 26 of them were from these regions with a high percentage of power produced by coal.

Besides fossil fuel price increases, other important factors have also contributed to high electricity prices. For example, the nation's electric system is growing, and new investment has been required to keep the lights on. Peak electrical demand in the U.S. grew nearly 12 percent from 2000 to summer of 2007 (an increase of approximately 80,000 MW).[7] To put that in context, Texas' peak demand in the summer of 2006 was over 62,339 MW,[8] so from 2000 to 2007, the U.S. added more than a Texas-sized amount of new demand. During that same time period, more than 210,000 MW of new power production capacity was put into operation, which is roughly equivalent to the addition of one large power plant a week over the entire period.[9] Using a conservative, back-of-the-envelope estimate of capital costs, this represents an investment of roughly $99 billion.[10]

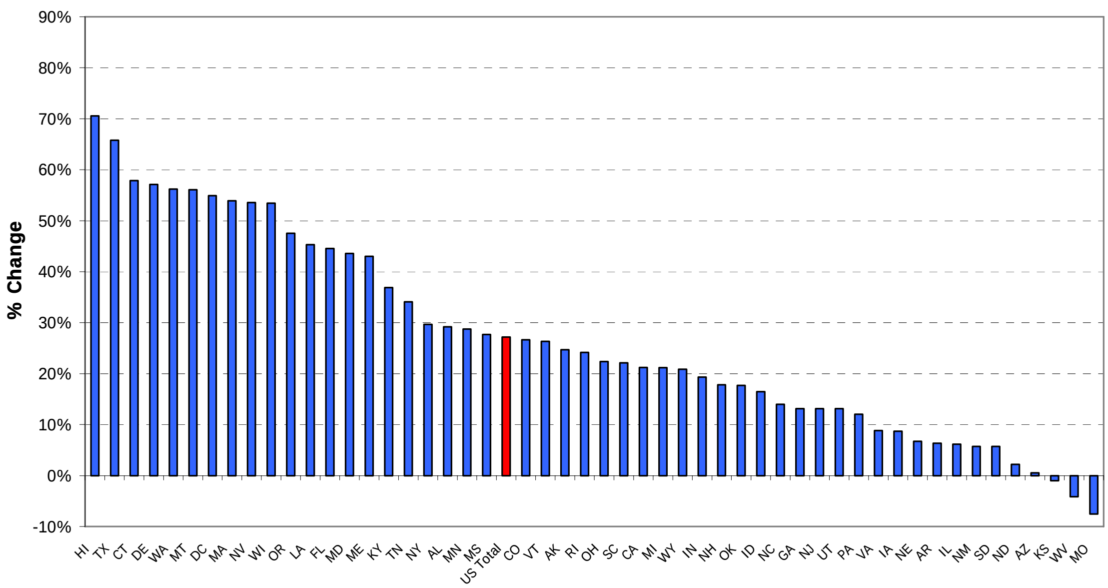
Figure 3
Mix of Fuel Used to Generate Electricity in Different U.S. Regions



Source: EIA.
*Note: MISO contains SD, NE, MO and KY.

Figure 4

Percent Change in Average Electricity Prices Across All States 1995 - 2007



Source: EIA.
Note: 2007 data repesents the annual average for 2007, using data from January through April.

In addition, power plants in many regions (e.g., California, Texas, and the Northeast/ Mid-Atlantic states) have had to install air-pollution control equipment and use cleaner (and more expensive) fuels in the past decade to address various clean-air requirements. The electric power sector spent more than $21 billion to come into compliance with air- and water-pollution laws from 2002 through 2005[11] and these costs have already begun to show up in electricity prices in these regions.

Investment in the power grid to deliver electricity from power plants to end users is up as well, after many years during which investment in power lines had been declining. Over 2,500 circuit miles of high voltage transmission lines were added in 2005 alone — equivalent to the length of a new line stretching most of the way across the U.S.[12] Utilities' annual investment in transmission and distribution systems amounted to approximately $24.2 billion in 2006, up from $10.4 billion in 1995.[13]

Further, cost of construction materials is up — sharply. Recent reports indicate significant cost increases in the materials and components associated with power projects, after a decline in such costs for decades.[14] "Prices for iron and steel, cement, and concrete — commodities used heavily in the construction of new energy projects — rose sharply from 2004 to 2006.... [I]ron and steel prices have increased by 9 percent from 2002 to 2003, 9 percent from 2003 to 2004, and 31 percent from 2004 to 2005."[15] Growing demand in other global markets, including China, exacerbates these conditions.

The indications are that the price effects of these combined factors are not likely to abate any time soon.[16] Investment requirements are also expected to remain high. The U.S. government estimates that 258,000 MW of new capacity is needed between 2006 and 2030, equivalent to four new "Texan" size electrical additions and a total investment of $412 billion (2005 dollars) — or even higher, if today's high construction-related cost increases continue.[17] These estimates may overstate investment requirements if Americans spend more on energy efficiency technologies than in the past, but in any case, future costs for electricity supply (and demand reduction) loom large. Further, grid operators see significant new investment requirements to expand and upgrade regional power service.[18] Installing more advanced metering technologies to enable consumers to see — and better manage — their electrical use would be in addition to those other costs.

Meeting existing clean-air regulations affecting power plants will cost the industry an additional $2.7 billion a year in 2010, and $4.4 billion in 2015, according to federal regulators.[19] Consumers in states relying on significant amounts of coal-fired generation will be most affected by these costs. Also, any costs related to the adoption of new laws to regulate greenhouse gas emissions from the power sector in the future will further affect cost of production at such plants. Some states (e.g., the Northeast and California) have already adopted caps on carbon emissions from power plants, and it appears increasingly likely that Congress will adopt a national program before too long. Estimates of such costs vary considerably, in part because of the uncertainty about what eventual carbon-control programs and laws will look like. For example, one study that modeled the impact of a national carbon policy imposing a price of $10/ton of CO_2 suggests increases in electricity rates in the Midwest and South would be approximately twice the size of such increases in New England and New York, in large part due to the Midwest's and the South's higher dependence on coal-fired generation. Even so, estimated electricity prices would still likely be lower in the South and Midwest than in New England and New York even taking these carbon-control-costs into account.[20]

In light of the realities of these costs — and the continuing growth in demand for electricity by Americans — it is simply unrealistic to expect that electricity prices are going to drop any time soon. Electricity is not cheap to produce, transmit and deliver, and electricity prices are not likely to decline materially in upcoming years — for a variety of legitimate reasons.

2. ALTHOUGH PRICES ARE RISING, ELECTRICITY STILL PROVIDES HIGH VALUE.

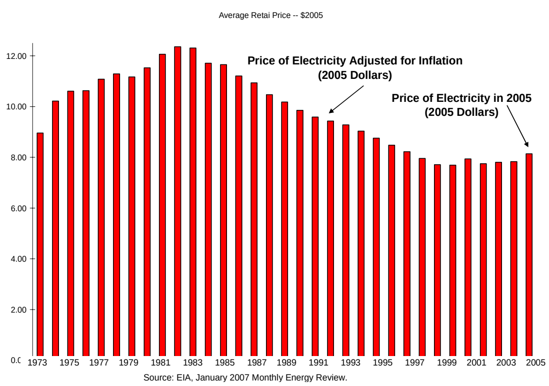
Compared to many other goods and services we depend upon in our daily lives, electricity remains a relative bargain. First, even though electricity prices have increased since 2000, inflation-adjusted electricity prices are still only about 2/3rd of what they were at their highest in the early 1980s. (See Figures 5.a and 5.b, below.) In those terms, electricity prices in 2000 were at their lowest point in over 20 years. Similarly, as a percentage of gross national product, the U.S. spends about 2/3rd less on electricity than what we spent during the 1980s. (See Figure 6.)

Figure 5

Average All-In Retail Price of Electricity (Including Fuel Costs), 1973-2005

Price of Electricity (adjusted for inflation)

Figure 5.a



Price of Electricity (real dollars)

Figure 5.b

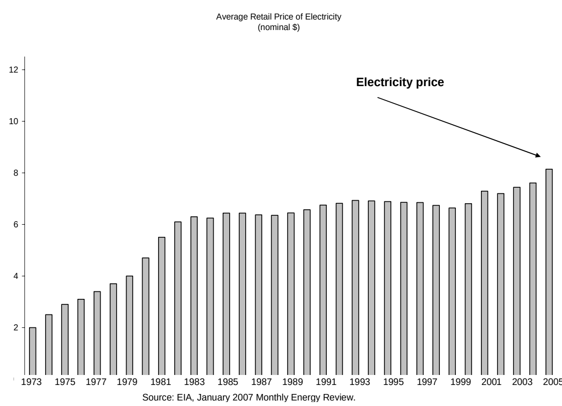
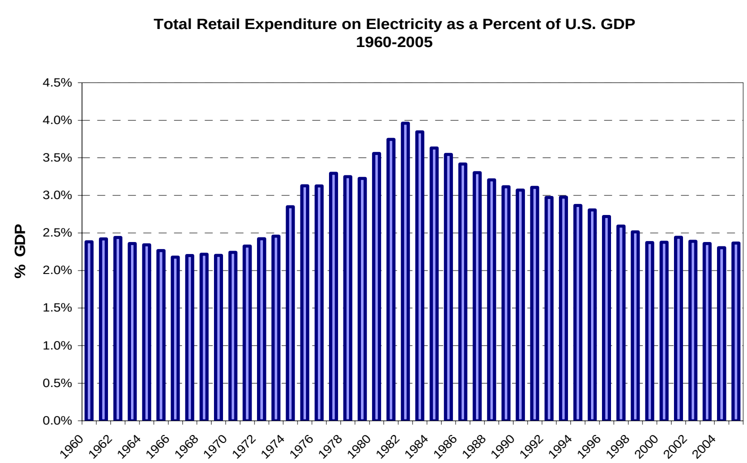


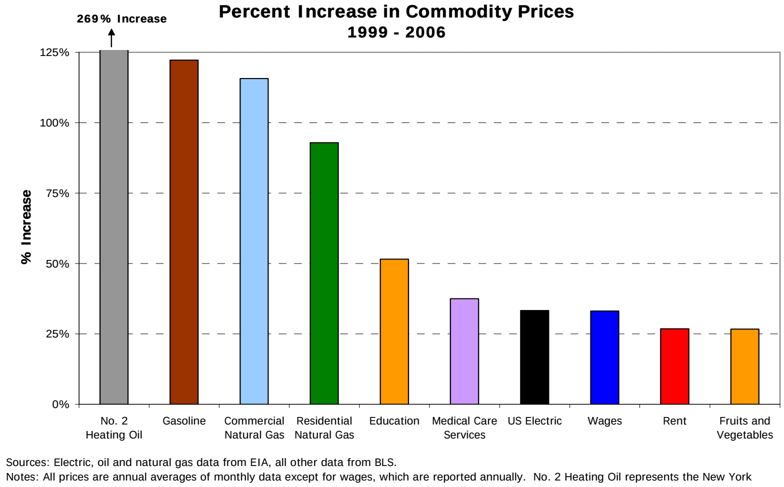
Figure 6



Sources: EIA, Annual Energy Review 2005, Table 8.9, Table 8.10, and Appendix D1

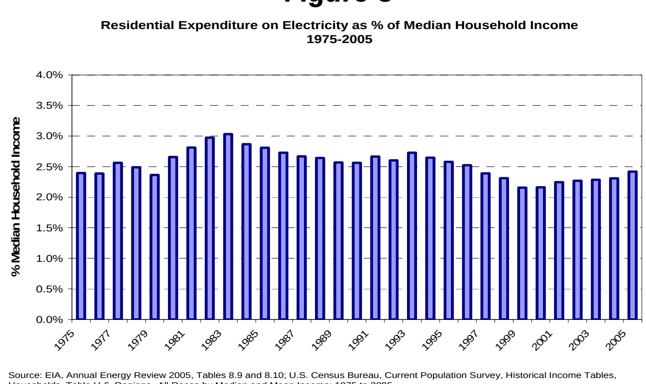
In spite of recent increases, electricity prices have risen more slowly than those for other goods and services, as shown in Figure 7. Among different types of energy purchased by consumers from 1999 through 2006, electricity price increases were lower (33 percent) than those for heating oil (269 percent), gasoline (122 percent), and natural gas delivered to commercial users (116 percent) and to homes (93 percent). During the same time frame, educational expenses rose 52 percent, while medical care expenses increased 37 percent. Electricity prices rose at about the same rate as wages (33 percent), and only slightly higher than other expenses (e.g., rent, fruits/vegetables).

Figure 7



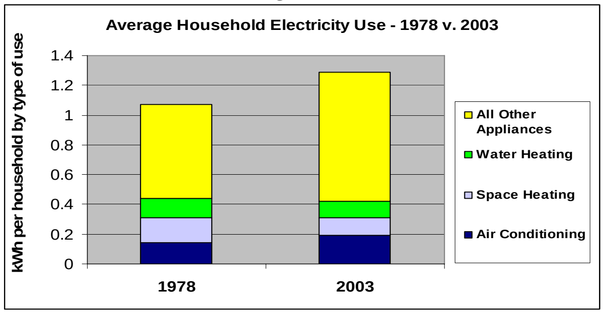
Again, to put electricity price increases in context, household electricity expenses as a percentage of household median income are no higher now than they were a decade ago (Figure 8), yet the average American is using much more electricity than in the past (as shown in Figure 9, which indicates that the average household's electricity use per hour has increased 25 percent in the past quarter century).[21]

Figure 8



These trends in increasing use of electricity are hardly surprising, given the significant increase in electronic consumer products and in the many technologies and tools in our offices, shops and factories that depend on reliable electricity supplies. We tend to forget that every cell phone charger, every computer, and every air conditioner adds to our reliance on electricity. Overall, our standard of living depends on the invisible energy source that's delivered to the socket.

Figure 9



Source: Basheda et. al., "Why are Electricity Prices Increasing?" 2007, Appendix A.

3. ELECTRICITY PRICES SEEM TO BE RISING EVERYWHERE, AND IT'S TOO SIMPLE TO ASSIGN THE PRICE INCREASES TO EITHER "REGULATION" OR "COMPETITION."

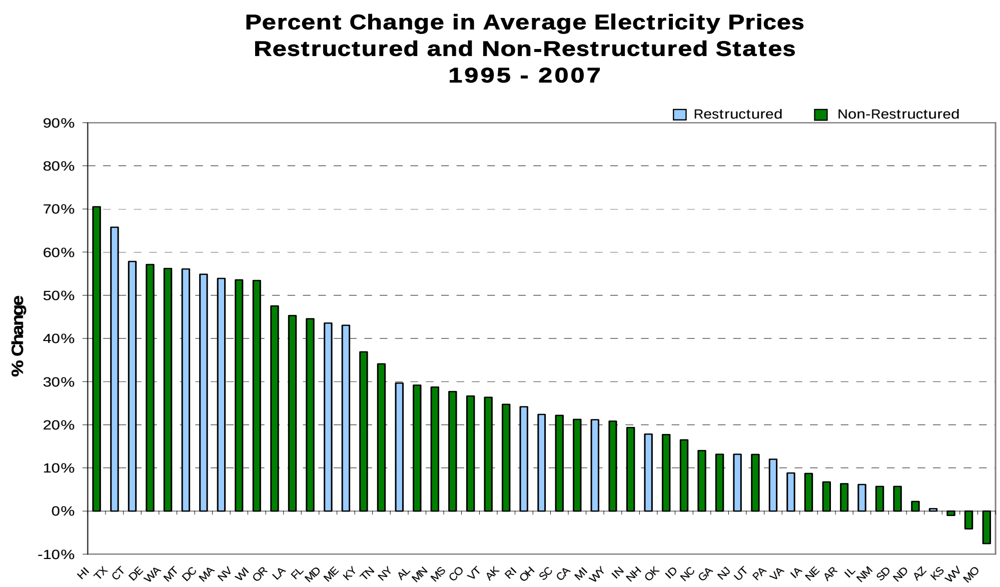
While electricity prices have risen all around the country, some regions' price increases have been higher and more volatile than others. One factor — a region's dependence on coal to produce power — was mentioned previously as important in regions experiencing lower prices and smaller price increases.

One nagging question, though, is whether there is something else to blame — that is, whether the steps taken to introduce competition into the industry over the past decade have rendered it more susceptible to price increases. Some states took steps to restructure their electric industries, allowing companies other than electric utilities to provide power to consumers, giving non-utility generators the opportunity to buy utility power plants, opening up the power sector for greater competition and investment, moving to market mechanisms (rather than regulators' oversight of utilities' cost-based investments) as the means to set electricity prices, and so forth. Many regions — including restructured and non-restructured states — developed Regional Transmission Organizations ("RTOs") to independently operate the grid and to administer bid-based centralized wholesale power markets, using them to determine efficient dispatch as well as market-clearing prices. In a general sense, many of these trends to restructure the electric industry occurred in parallel with the electricity price increases experienced in some parts of the country, so the question is whether these structural changes caused — rather than accompanied — the recent price increases. [22]

To be clear, though, price increases have occurred in both states that restructured and states that did not. Figure 10 reports the percentage change in rates in the various states from 1995 through April 2007. The period spans the years between when many states began to consider implementing changes in the industry, on the one hand, and when they ended their "rate freezes" that were adopted as part of the restructuring changes, on the other.[23] (States that restructured are light blue while those retaining a traditional industry structure are dark green.) Over this period, average retail prices in states that restructured their electric industries rose only slightly higher than rates in the states that retained traditional regulation.[24]

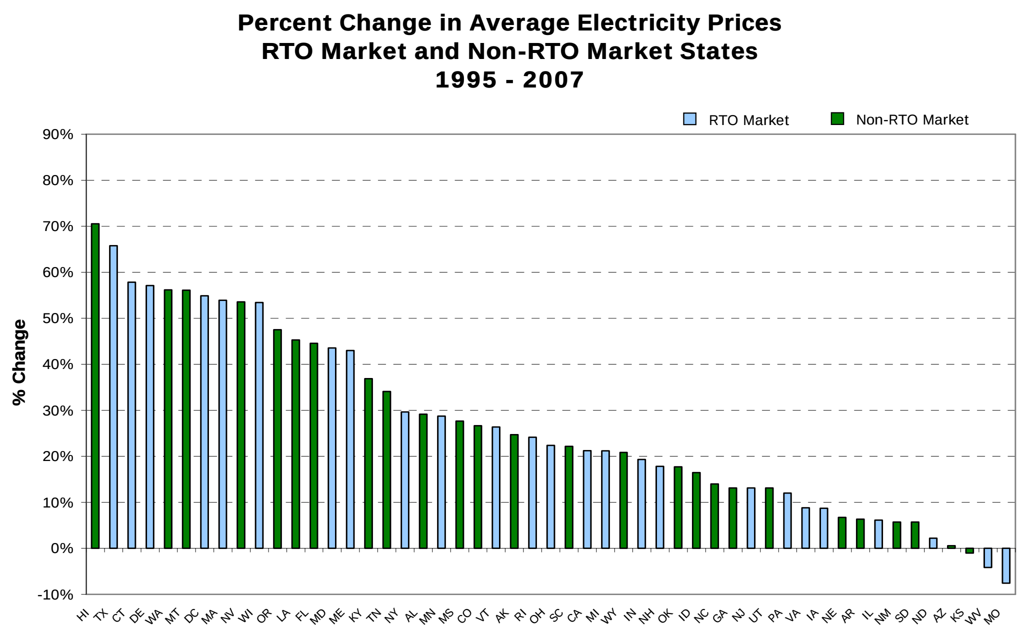
Figure 11 shows slightly different information, comparing the rates in different states according to whether their companies principally joined an RTO, or not. The comparison period spans from the beginning of 1995 — around the time when industry participants in many regions began to explore establishing an RTO — to those in April 2007.[25] Here, states with utilities that are members of organized wholesale power markets administered by RTOs are in light blue, while those states not principally served by an RTO market are in dark green. These figures show that states with restructured electric industries — whether in states that adopted retail choice or states whose utilities joined RTOS — are spread fairly evenly throughout the distribution of all states, some with high price increases and others with lower price impacts since 1995.

Figure 10



Source: EIA.

Figure 11



Source: EIA.

Both Figures 10 and 11 show several themes. First, changes in states' electricity prices are all over the map, with average price increases from 1995 to early 2007 as high as 71 percent (in Hawaii, a state that did not restructure its electric industry), to as low as -8 percent (in Missouri — a state served by an RTO market, but that also did not restructure its electric industry to allow for retail choice). Figures 10 and 11 also suggest that "restructuring" has not had an easily discernable and consistent impact on prices across the various states. Rather, the differences in retail prices relate to a number of differences across states and regions, including — along with restructuring status and wholesale market design — such things as the availability of unique resources for generating power (e.g., hydro in the Pacific Northwest); regional differences in fuel costs (largely due to power generation mix and fuel transportation costs, as shown in Figure 3); the types of customers served; the size (or scale) of utilities; economic growth rates, and the need for new generation and transmission investment; the strictness of environmental requirements; a variety of differences in state-level regulations; taxes; and labor and materials costs.[26]

It is fairly well understood that for the most part, the states that pursued early efforts to restructure their electric industries were ones that already had high electricity prices during the 1990s. These were states where at the time, a number of features — rate increases associated with new power plant investment, cost overruns, expensive long-term contracts, combined with opportunities to build new generating capacity at costs lower than prevailing electricity prices — motivated large electricity consumers (and their political representatives) to complain about utilities' high price levels under traditional regulation and seek the option to buy power from the electricity supplier of their choice.

Fifteen of the 17 states that now[27] have higher-than-average retail electricity rates were also among the 19 states with higher-than-average rates on the eve of restructuring the electric industry in 1996.[28] Almost all of the high-priced states[29] in 1996 went on to restructure their industries during the 1990s, and several others[30] did so as well.

Notably, in 1995 the states that eventually restructured had electricity rates that were 22 percent higher (on average) than the other states (and 24 percent higher in 1997, on the eve of many restructuring laws);[31] by 2006, this gap had narrowed to 20 percent higher (having been as low as 12 percent higher in 2000, near the start of natural gas price increases).[32] Stated another way, electricity prices were higher in restructured states than in non-restructured states in 1995, but are less so in 2006. In fact, an important factor motivating states to implement restructuring were the high prices that prevailed during the 1990s and the potential for restructuring to achieve reductions in such rates relative to what they otherwise would have been.

4. DESPITE SOME NEW COSTS AND SLOW DEVELOPMENT OF RETAIL COMPETITION (EXCEPT FOR LARGE CUSTOMERS), RESTRUCTURED MARKETS HAVE PROVIDED MEASURABLE BENEFITS.

There were many motivations at the roots of past efforts to introduce competition into the electric industry: desires to produce and deliver power more efficiently; intentions to reduce the influence of utilities' preferences for investments that expanded rate-base even when such investments failed to provide commensurate consumer benefits; hopes to bring about innovation and improvements in risk management; and the goal of allowing consumers to make choices about their power suppliers. While many surely wanted "lower prices" and many promised this would be the result of restructuring, economists have reminded us that this was in effect a goal of having prices lower than they would otherwise be under traditional regulation. To date, some of these benefits have transpired; others have been less successful.[33]

Across the country in states that have allowed customers to choose their retail supplier of power, many large, sophisticated electricity customers including universities, factories, large and small department stores, and others, have opted to manage their own power supplies — determining their supplier, managing their demand, and hedging their price risks.[34] For the most part, even these actions have not prevented such customers from feeling the effect of the overall rise in the price of electricity and of the underlying fuels used to generate it, nor could they have avoided it under rate regulation. But it has enabled them to realize savings relative to what their prices would have been, had they continued to buy power from the utility. By contrast, small residential customers has been far less successful, when measured by the statistics showing that few small residential customers have chosen, or even had a feasible option, to buy power from a competitive retail supplier.[35] A major contributing factor to this slow development has been rate freezes and price caps implemented in many states as part of the restructuring plans which have shielded small customers from price increases for many years.

Many of the nation's power plants are now much more efficient than in the past. Just as in any competitive market, the opportunity to profit by producing at a cost below market prices — and to increase output through productivity gains — has created incentives for producers to undertake needed investments and improvements in operating practices to achieve such cost savings.[36] Plant divestiture combined with competitive conditions has led to operational improvements in existing plants that in one way or another have reduced their operating costs.[37] These improvements include: increases in the efficiency of fuel-consumption (i.e., heat rates) of fossil fuel-fired facilities;[38] decreases in the length of refueling outages, lower operations and maintenance expenses, and greater plant availability at nuclear facilities;[39] and decreases in labor and other non-fuel operations and maintenance costs across all facilities.[40] Improvements that increase plant availability are particularly valuable because they increase the quantity of power produced by less-costly power facilities. The cost savings from such increases in plant availability — as measured by the difference between the cost of facilities with improved availability and the most expensive generation that does not need to be dispatched — has been estimated by a number of studies.[41]

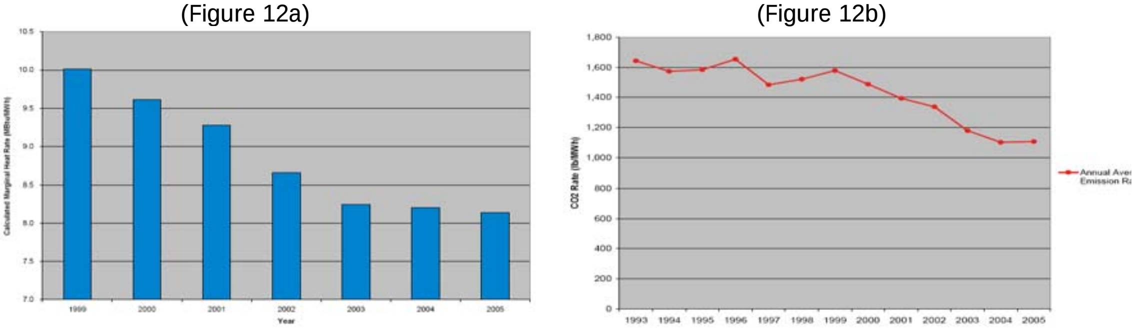
Another benefit of restructured markets is that they have improved the efficiency by which plants are "dispatched" (i.e., turned on and off) to meet consumer demand. In principal, all grid operators, whether operating in markets administered by RTO/ISOs or in a particular utility's "control area," attempt to dispatch the least-costly plants to meet consumer load. Restructuring has increased the efficiency of these decisions in a number of ways. It has facilitated the increased "geography" of dispatch decisions, which allows costs to decline by using lower-cost resources in one region to displace higher-cost power resources in another.[42] One study of geographic consolidation in New York which also examined the impact of reduced outage rates for nuclear and fossil fuel units, found benefits of between $100 and $200 million per year, which is roughly 5 percent of the system-wide production and fixed operation and maintenance costs.[43] Second, certain long-standing barriers to efficient trade across regions (e.g., "pancaked" layers of transmission rates needed to transport power across multiple regions) have been reduced or eliminated, helping to reduce the overall costs to supply power. Another study of the benefits of the recent expansion of

PJM to include the three Midwest utilities (AEP, ComEd, and DPL) found annual benefits of about $70 million in PJM and about $85 million when including regions outside of PJM.[44]

Other benefits have been attributed to improvements in wholesale electricity markets. Adding newer more efficient power production technology and dispatching the system more efficiently has led to reductions in air emissions from power plants in some competitive electric markets, as noted in studies of New England.[45] There, the region increased its power plant capacity by more than 40 percent (i.e., by nearly 9,800 MW) over the period from 1999 through 2005, with corresponding improvements in heat rates (with lower heat rate reflecting less fuel used to produce power) and overall emissions of carbon dioxide (as shown in Figures 12a and 12b, below).

Figure 12
Recent Improvements in Power Plant Efficiency & Emissions: New England Example

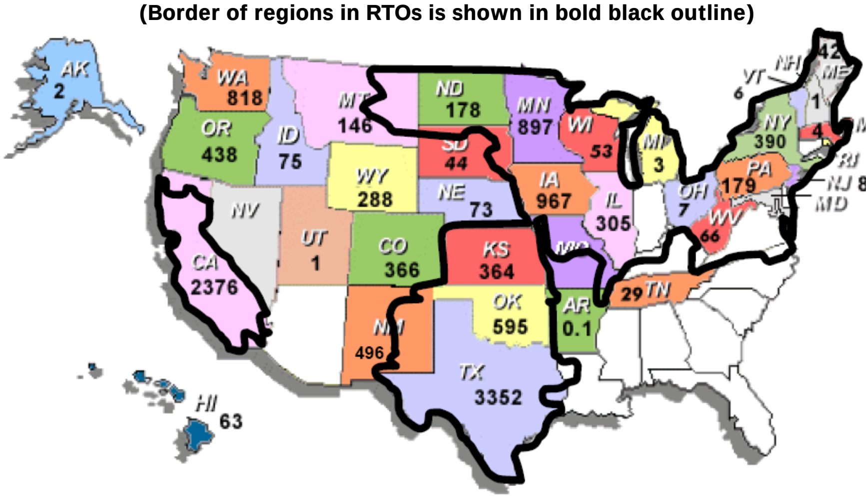
Heat Rate (MBtu per MWh) '99-'05 (Figure 12a) | **Emissions of CO2 (lb. per MWh) '93-'05** (Figure 12b)



Source: ISO-NE (2007), 2005 New England Marginal Emission Rate Analysis, Figures 5.1, 5.4.
Figures show the historically calculated heat rates and CO2 emissions of the marginal generator in all hours of the year.

In the past decade, renewable power resources (like wind projects) have been added principally in parts of the country served by RTO-administered markets, in large part because of the much-more-favorable transmission policies that enable suppliers to obtain delivery capacity, the visibility of prices by location and time of day, and the ability to sell into spot markets and/or multiple buyers. (See Figure 13.)

Figure 13:
Total Installed U.S. Wind Energy Capacity (MW in each state as of June 2007
(Border of regions in RTOs is shown in bold black outline)



Source: http://www.awea.org/utility/wind_overview.html (total wind capacity = 12,634 MW as of June 30, 2007)
http://www.ferc.gov/industries/electric/indus-act/rto/rto-map.asp (RTOs as of September 2007)

Another way that competitive power markets have led to innovation, efficiencies, environmental benefits, and reliable power supply is through "demand response." For example, on August 8th, 2007, retail customers in the PJM region voluntarily reduced their demand by 1,945 MW (roughly equivalent in size to two large nuclear power plants) in response to real-time price signals in PJM's wholesale market; these customers were participants in PJM's "demand response" program which allows these customers to be paid the same amount for reducing demand for electricity as generators are paid for supplying electricity.[46] Had these customers not provided power to PJM, other more expensive power supplies would have had to be dispatched, or PJM might have had to resort to involuntary disruptions of service to customers. PJM's wholesale market, like those in other regions like New England, New York, the Midwest ISO region, and California, provides the type of wholesale price transparency that enables such customer-response programs to operate. Further improvements in retail price transparency (allowing many customers to see prices as they change over time at different times of day), would further enhance these efficiency gains. The benefits associated with price transparency, improved access to transmission, and other effects have been identified, although (for many important technical reasons) it is exceedingly difficult to quantify these effects with precision.[47]

Of course, these benefits have been accompanied by incremental administrative costs incurred to start up RTOs and the markets they administer. These costs have ranged from $55 million for New England, to $137 million and $140 million for Texas and for PJM, respectively.[48] Recent indications are that as RTOs mature, their administrative costs have seemed to level off.[49] PJM, for example, the largest market, has recently begun to provide service under tariffs that involve commitments not to increase RTO administrative costs. Notably, one of the activities supported in these administrative costs at RTOs is a type of highly visible and active market monitoring function. Such functions are much more difficult to implement in bilateral markets (and therefore tend not to exist in the same way) without the kind of price transparency existing in RTO-administered markets.[50]

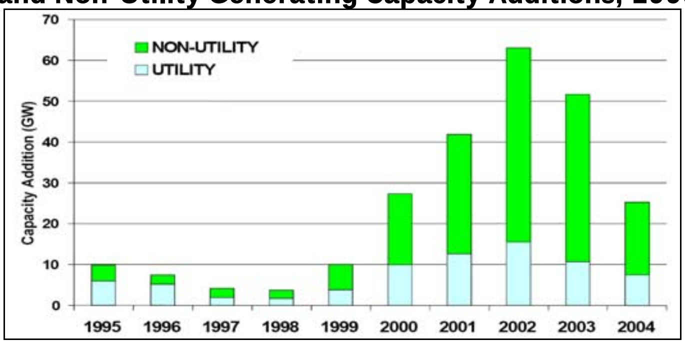
5. CONSUMERS AND SUPPLIERS HAVE BOTH SEEN BENEFITS.

Anyone who has studied the question of "who benefits" as a result of the introduction of competition in the electric industry over the past decades finds the technical and conceptual challenges daunting, to say the least. For example, a federal task force established by the Energy Policy Act of 2005 to "conduct a study and analysis of competition within the wholesale and retail market for electric energy in the United States"[51] avoids drawing bottom-line conclusions on this particular question,[52] in no small part due to the technical difficulties in doing so. As hard as it is to estimate "societal" benefits and costs associated with restructuring the electric industry, it is still more difficult to determine how (and whether) the net benefits of such reforms are shared across different parties — consumers, suppliers, investors, utilities, and so forth.

Clearly, many large sophisticated consumers of power who now arrange for their own electricity supplies have found it beneficial to have that option, even if they do not like the fact that electricity prices have increased in recent years. Anecdotal evidence suggests significant benefits to large, sophisticated electricity customers (like universities and other educational institutions, hospitals, hotels, factories, food stores, commercial office buildings, large retail chains), helping them control their costs and the prices of goods and services they provide to their own customers.[53]

Consumers have benefited from changes in the industry that have imposed greater risks on investors than was the case under traditional cost-based rate regulation. As shown in Figure 14, the vast majority of investment in generating units over the decade since 1995 has been made by non-utility entities,[54] with investors bearing risks of cost overruns and surplus capacity. Competitive market structures typically provide no assurances about future prices for power generated, so owners of such generating facilities are at risk to recover a return of and on their investment through competitive markets. This contrasts sharply with investment patterns in the prior decades, when most of the capacity additions were made by regulated electric utilities.[55] While utilities had to demonstrate that their investments were prudent, once such approvals were in hand, consumers have tended to repay for such investment costs, without regard to power plant operational performance.[56]

Figure 14
Utility and Non-Utility Generating Capacity Additions, 1995-2004



Source: Electric Energy Market Competition Task Force, "Report to Congress on Competition in Wholesale and Retail Markets for Electric Energy, Pursuant to Section 1815 of the Energy Policy Act of 2005," page 35, using FERC analysis of Platts PowerDat data.

As a result of these changes, for the most part, consumers have not borne the financial burden of the industry's over-supply of generating capacity that existed in many parts of the U.S. after the massive infusion of new generating capacity additions since 2000; investors have borne the cost of this surplus investment.[57] As noted previously, a rough, conservative estimate of the capital costs of the capacity added during 2000 through 2005 is $99 billion.

Clearly, some investors have done well under competition, while others have not. For example, a number of competitive power suppliers that have investments in low-cost power production facilities in RTO-administered markets (e.g., PJM, NYISO, ISO-NE, Texas) have seen significant returns in recent years, as high natural gas prices have driven up the prices in (and therefore the revenues for sales into) these wholesale spot markets. Much of this capacity — older and relatively efficient nuclear power plants, coal-fired power plants, and hydroelectric facilities — was acquired by investors during the utility divestitures and/or asset spin-offs that occurred over the past decade as part of restructuring plans. As such, these assets are not a part of the utility rate base where investment costs are recovered in regulated retail rates. Rather, revenues in markets are necessary to cover investment, operating and maintenance, fuel purchases and all other costs for such plants. While information on shareholder profits tied to individual power plants in competitive markets tends not to be publicly available, one study of profits earned by companies owning unregulated generating capacity in PJM indicated that returns have been higher than companies that remained entirely regulated.[58] Many of these companies are embarking on major capital investment programs for energy facilities.

Many investors in some regional markets — notably the Northeast — have also experienced relatively lean periods, as surplus capacity conditions and high fuel prices led to lower-than-anticipated utilization and poor financial performance for many new plants. Many of the competitive power generators operating in restructured markets were forced into bankruptcy after 2000, and others had speculative credit ratings for a number of years before restructuring their businesses more recently.[59] As market conditions have improved, some of these companies have reemerged from bankruptcy and restored some of their market value.[60]

So clearly, as in all markets, some investors have done well, and others less well. Some companies went through distressing periods, and disappeared altogether. In most regions — with the possible exception of California during the 2000-2001 electricity crisis — consumers were shielded from the effects of bankruptcies as power plants were required to remain operating even during periods of non-payment and bankruptcy to provide power supplies to homes, offices, hospitals, schools, and factories.

6. IT'S NOT HARMFUL TO CONSUMERS TO HAVE INVESTORS SEEKING ADEQUATE RETURNS IN THE ELECTRIC INDUSTRY. IT'S HOW THIS EXTREMELY CAPITAL-INTENSIVE INDUSTRY FINDS NECESSARY RESOURCES FOR RELIABILITY.

In the U.S. most — although not all — electricity is supplied by shareholder-owned companies. This means that a substantial portion of this extremely capital-intensive industry is supported by private investors. Stated otherwise, consumers around the country depend on the active interest and financial motivations of private investors. It is not a bad thing for electricity consumers, therefore, that investors find favorable returns in the electric industry. Given the future capital requirements needed in the electric industry, this will continue to be an important element of assuring reliable supplies of power in the future.

While 80 percent of generating capacity is owned by investor-owned companies — whether by utilities (40 percent) or by non-utility generators (40 percent) — not all of the power supplied in the US comes from privately owned companies. As an imprecise estimate, if 80 percent of the new electric investment required in upcoming years — whether for power plants, transmission lines, distribution systems, energy efficiency measures, other green technologies and pollution control equipment, advanced metering systems — were to come from private investors, this could amount to several hundred billion dollars, give or take many millions.[61] Needless to say, this is a capital intensive industry. For the U.S. electric industry to attract those kinds of investment dollars in future years — and for American consumers to get the value of the power supplied through those new investments — it will be extremely important to offer attractive returns. This will be essential, whether a particular region adopts a competitive or a regulated industry model.

7. NEITHER REGULATION NOR COMPETITION IS PERFECT. HOWEVER, LONG-TERM CAPITAL INVESTMENT WILL BE ATTRACTED TO PLACES WHERE THERE IS A STABLE REGULATORY FRAMEWORK.

Everyone who pays attention to issues in the electric industry has a running list of problems they've come across over the years. In recent years, in spite of the differences among the lists, many of them seem to have one thing in common: Either implicitly or explicitly, they tend to compare the industry as it exists in a real time and place with some idealized notion of what things would be like "if only" one or another thing occurred. These "if only" worlds tend to be idealized versions of realities the list-maker would like to see.

In the mid-1990s, when regulated prices seemed high and out of control, many observers envisioned what prices might be like in an idealized version of a market place. The idea was to tame costs and send better incentives for risk and reward through introduction of market forces into the electric industry. In many places — especially the ones with highest rates — the industry was restructured, with the changes accomplished through a myriad of compromises that seemed practical and necessary at the time but ended up with a variety of shortcomings in hindsight. The results are somewhat less than the idealized competitive outcomes that were imagined a decade ago, and have led to hybrid "market" designs in many places that fall somewhere between regulation and competition. While certainly some markets have developed more quickly and better reflect these idealized competitive outcomes than others, as a nation we learned that in some regions at least, the bargains and compromises produced some outcomes we never envisioned and clearly haven't liked.

Now, frustrated with today's high electricity rates in those regions, many people question whether the right road was taken and what reforms are now needed to bring things back on track. Some suggest a return to what they view as a more protective set of arrangements they associate with regulation of the past. With this in mind, however, it is worthwhile remembering that the efforts to restructure the industry a decade ago stemmed from desires to protect consumers from absorbing so much of utilities' investment risk.

Traditional regulation has had its notorious problems, just as today's version of competition has its own. Many scholars and industry experts have studied these issues, and most tend to conclude that we should remember that "in the good old days," we did not have perfect regulation any more than we have perfect competition today.[62] Today's debates that critique the imperfections of one approach or another could benefit from reminders that neither is ever as perfect as we imagine when we're comparing the realities we know with the "if only" reforms we're championing.

One of the challenges in this particular industry is that — for better or for worse — it is neither a pure monopoly, warranting regulation of all aspects of the industry, nor is it a pure market, allowing the full unleashing of market forces. Notably, even if it can be helpful to rely on market forces when we think it's useful, we can't seem to help ourselves from trying to fix things (like high prices) when they occur. This situation poses a fundamental challenge for the industry, allowing us to remain somewhere between a product with many commodity-like features and yet retaining a special character that causes politicians to want to intervene when markets are behaving in ways we find uncomfortable.

In light of this, a useful foundation for constructive discussions in this industry is the notion that neither regulation nor competition is perfect. This provides a basis for a reality-based dialogue — one that gravitates towards finding improvements in industry approaches in place in different regions (as described in the next section), rather than attempts to throw out the current industry model in hopes that the alternative will be something better. This will support the kind of stable regulatory environments that investors find attractive.

8. MARKET DESIGN ACTUALLY MATTERS, AND IS STILL EVOLVING.

While today's electricity markets are neither perfect nor fundamentally flawed,[63] there are still important elements of market design that would improve their performance. While the issues vary from region to region, and across retail and wholesale markets, there is hardly a regulator, a market administrator, a market participant, or an academic scholar familiar with wholesale and retail power markets in the U.S. who doesn't have ideas of how to improve their performance. FERC has many of these improvements actively on its radar screens.[64] And in states that have not aggressively restructured their electric industry, consumers would likely benefit from the introduction of greater competitive processes.

In regions with organized wholesale markets, for example, the suggested improvements differ by region, but there are some common themes. These include: [65] implementing clear capacity obligations and forward capacity markets (and/or allowing energy prices to reflect the "value of lost load"); further refining and deepening the demand-response side of the market; improving long-term regional transmission planning; allowing long-term financial transmission rights; improving specific ancillary service markets; establishing more precise and consistent definitions of what constitutes workably competitive markets, and sharing best practices for monitoring and mitigating markets consistent with those definitions; improving various "seams" issues at the borders of markets; allowing long-term contracting in ways that align well with organized market design; assuring greater information sharing; improving price signals to retail consumers so that many fewer see average prices in all hours; and better managing the costs to administer wholesale markets.

In regions with regulated vertically integrated utilities, improvements to wholesale markets tend to include: adopting better (e.g., more rigorous, disciplined and independently overseen) competitive resource solicitations to assure least-cost supply additions; assuring non-discriminatory access to transmission; improving regional transmission planning; designing more transparency in the price terms of bilateral contracts; using locational pricing as a tool for planning or for encouraging greater demand response, even if not an element of market structure *per se*; developing long-term transmission rights; developing more sophisticated means to hedge price risks; adopting regulatory policies that align utilities' financial incentives with adoption of cost-effective energy efficiency measures; and vigorous regulatory pursuit of instances of manipulation of prices in energy trading markets.

FERC and many states have had a number of these issues on their agendas for some time. There is strong support, for example, for ensuring that strong market oversight is needed in all regions, to build confidence that markets are functioning — whether organized or bilateral. There is strong agreement that it would be useful to encourage the development of more sophisticated financial markets to allow market participants to better hedge price risks — as has occurred in other energy markets. There are suggestions that FERC should use its rate authority over transmission so that all users of transmission in interstate commerce should pay the FERC-approved rates for transmission, regardless of whether transmission and electricity sales are bundled or not.[66]

Some industry observers are looking for much-more far-reaching changes, especially in state forums. Ever since electricity prices began to rise more visibly a few years ago, some "to do" lists include changes that *turn* or *reverse* direction, rather than make incremental changes. There are those in some restructured states that want to go back to traditional regulation, or to insert elements familiar to the regulated model into the state's industry structure. Some of these changes are certainly possible. Some of the changes being proposed are not sensible, however, because they risk creating an inconsistent set of messages to market participants about market rules and regulations, with the result of undermining the benefits of market forces and unduly shifting risk to consumers. While it is likely that all regions will retain some degree of hybrid forms, some combinations of pieces work together while others do not.

Stepping back from the detail of changes recommended in one place or another, it is useful to recall the "law of the instrument." Hammers are useful for solving some problems, but not others. We know from all sorts of examples in our daily lives, we can sometimes make things worse when we use the wrong tool or part to fix a problem. We may have in mind a regulatory remedy to try to fix a market design, but sometimes the details of how well the "fix" fits with other aspects of the market matter in terms of whether we'll end up with something better than we started. Just because you have some Toyota auto parts lying around doesn't mean that they'll work if you install them in the Prius. In the electric industry with its technical complexity, it's hard to adopt things that make things better, and unfortunately, it's often easier to make things worse.

The point is that in this industry, deciding whether a proposed remedy "fits" is sometimes just as important a decision as whether to do something at all. Policy makers should take care to look for regulatory stability and to choose their policy instruments with care. This admonition applies equally to states that have or have not adopted competitive industry structures.

States that have retained their traditional vertically integrated industry structures, for example, would be wise to adopt policies that afford their consumers the benefits of market forces. An illustration of this would be to adopt well-designed and disciplined competitive procurement processes that bind the utilities' plans and proposals to the same regulatory requirements as those to which third-party suppliers are held. Utilities are typically required to use competitive procurements for a wide variety of services (including contracting for goods and services), but typically are not required by regulators to submit binding bids covering the price and other terms at which they propose to supply new generating resources in the future. Doing so could introduce the discipline required of others when they submit their bids, and would protect consumers from cost overruns that often accompany large-scale construction programs not obliged to live within "not to exceed" cost caps.[67]

States with retail choice, on the other hand, would be wise to resist the temptation to add policies and regulatory approaches (such as an over-reliance on long-term power contracts, integrated resource planning or other complex resource portfolio obligations and responsibilities for local distribution utilities) that are better suited to a regulated industry framework in which retail consumers are not permitted to shop for power from an alternative electricity supplier. Imposing such obligations that shift financial and economic risk to consumers, while continuing to allow those customers to migrate to other suppliers seems like a formula for problems to arise in the future, should economic conditions change leaving the utilities' supplies priced above market rates.

Either type of regulatory environment can support policies that promote more aggressive targets for cost-effective energy efficiency, by the way, although the policies adopted in the two kinds of states should be mindful to design policies that align well with the incentives built into the overall industry structure.

9. TECHNOLOGY DOESN'T JUST HAPPEN IN THIS INDUSTRY WITHOUT THE INCENTIVES EMBEDDED IN MARKET RULES.

The electric industry is inherently technology-based. It has always operated through complex, enormously technical, engineered systems of generators, transmission lines, distribution systems, and a variety of control technologies. In some respects, the industry relies on tried-and-true technologies: a large portion of the power system's physical assets are older than the people running them. But in its highly interconnected systems today, the industry depends on modern technologies. And our economy with its increasingly high degree of reliance on electronic systems depends on assurance of adequate infrastructure and highly-reliable system operations into the future.

A common plea in this industry is that new technology is needed. New types of power plants are necessary for assuring that the next cohort of long-lived power plant investments are clean and efficient, so that (among other things) the carbon emissions from the electric industry begin to decline in ways that address the requirements of climate change. Technology is also required — and already available — for enhanced, more reliable and more secure transmission investments, allowing for a more robust electric system that positions the U.S. for the needs of the 21st century. Additionally, many of the technologies for enabling customers to better manage and make efficient use of electricity are already known, but have only been deployed in very limited contexts.

Achieving the economic, reliability and environmental benefits of technology adoption is critically important for the country, but depends upon the kinds of significant investment described above, and the kinds of paradigm shift described below. It won't just happen without the adoption of public policies and corporate decisions by industry leaders that result in greater spending on research and development and adoption of advanced technology.

10. CONSUMERS WILL BE BETTER ABLE TO REALIZE THE FULL BENEFITS OF COMPETITIVE WHOLESALE MARKETS IF THEY ARE BROUGHT OUT OF THE DARK.

As Americans look forward to continuing to enjoy the benefits of modern society, including the values afforded by reliable and cleaner energy supplies, it will be useful — if not necessary — to begin to make electricity more visible. Most customers — and virtually all small electricity consumers — only see average prices and billing statements showing only monthly energy use. Most consumers have no idea that it costs more to provide them with power in the middle of the day than during the evening hours, with prices spiking during the hottest hours of the year. Most customers do not know which appliance or electronic equipment uses more electricity than others. Few consumers are aware that many appliances that are turned off still draw electricity, or that many of those cell-phone chargers draw power around the clock whether or not the phone is in the docking station. Most electricity consumers — except perhaps those large electricity users for whom electricity constitutes a major budget item — simply make little connection between their patterns of electricity use and the size of their electricity bills.

Given the realities of today's electricity supply — that it is not cheap — Americans would benefit greatly by being brought out of the dark. Consumers' demand is driving investment requirements and costs to provide power. Consumers could better manage their own electricity bills if more light were shed on electricity realities.

There are ways to do this with technology, much of which already exists but awaits the regulatory incentives to be deployed into the hands of consumers. There are advanced meters and other "smart" equipment that allow customers to see how much it costs to supply power to different appliances at different times of day. There are devices and service providers who can offer relatively seamless ways to better manage customers' usage patterns — such as through cycling of air conditioners in ways that reduce the usage of a city's worth of air conditioners (and thus a significant amount of power requirements) without reducing comfort or convenience. Those who sign up can receive a check for their savings. Large sophisticated users of electricity are already adopting such devices and other ways to manage electricity and save money.[68] But small users who are shielded from knowledge of the prices to supply power at different times of day have weak (if any) motivation to pursue such devices. So, the technology may be there to keep them informed, but there is insufficient motivation to adopt it.

Enabling this kind of customer response to market conditions is critical to the performance of markets themselves, as well as to the ability of consumers to manage their energy use and electricity bills. The value of harnessing price signals to help supply resources to the system and to discipline prices through the operation of both supply and demand has been seen in recent years in many RTO-administered wholesale markets. This was noted previously with regard to the 1,945 MW of "customer-supplied" capacity provided through demand response program participants in PJM on August 8th, 2007. The NYISO operates demand-response programs in which (as of April 2007) approximately 2,000 customers had registered to provide demand-response capacity totaling approximately 1,600 MW.[69] As of August 2007, ISO-NE had registered 2,031 demand response "assets," totaling 1,149 MW,[70] equivalent to 4 percent of New England's highest electricity peak use (28,130 MW, which occurred in the summer of 2006).[71] It is no accident that these programs have moved quite aggressively in these markets in recent years, since the transparency of hourly wholesale prices has enabled the possibility of customers seeing electricity prices and making decisions for themselves about whether they prefer to curtail their usage when prices hit a particular threshold. Without this kind of price transparency — something that typically does not exist in regions without RTOs — these markets are significantly impeded and customers (those who participate in the programs, as well as other non-participants) would be paying much more for their electricity bills.[72]

In the future, leaders would do well to allow for the blinders to be taken off of consumers. This doesn't mean that everyone will have to move electricity issues to the top of their agenda. It does mean, however, that electricity has to be more visible in terms of prices, sending different kinds of messages to consumers than they get when they simply open the bill at the end of the month. Electricity is not cheap; it is more expensive at certain times of day. And electricity use can be *much better* managed, not just by large consumers but by smaller ones as well. Consumers can be empowered in terms of having better control over their electricity bills; but they won't be able to become empowered if they are kept in the dark and protected from the truth that electricity is more expensive and likely to remain that way for the foreseeable future.

Sending this message is essential, requires gumption, and needs to occur whether a region has adopted a competitive industry model or retained vertically-integrated monopoly utilities. It also requires recognition that in the electric industry — like so many other aspects of our economy — there are strengths in the competitive market structure, with benefits for consumers.

CONCLUSION

As much as one would like to conclude otherwise, relatively high electricity prices are likely to be the "new normal" in the electric industry. This is our new reality — whether consumers are served in regions with vertically integrated electric utilities under cost-based regulation, or in ones relying substantially on markets. This reality stems from fundamental economic forces tied to global markets for fossil fuels and other products, and to the need to address other critical economic and social challenges such as continued demand for power, aging infrastructure and global warming. There is nothing fun about any of this, but it is not entirely a "bad news" story.

Electricity continues to fuel a national economy that is increasingly dependent upon machines, systems, tools, and devices that rely on electricity. Americans enjoy some of the most reliable electricity supplies available anywhere in the world. Presuming a degree of regulatory and policy stability going forward, we can expect private investors to supply capital for the grid, for greater improvements in energy efficiency and in power production facilities. We can look forward to an electric sector producing lower pollution levels than in the past. All of this is good for consumers.

Moreover, by better use of market mechanisms, consumers may be better positioned than in the past to determine how much and when they use electricity. Many large and sophisticated customers are already taking advantage of systems and services to help them manage their electricity use and electricity bills. Other electricity users, including smaller commercial and residential consumers, may soon become more "empowered" to manage their supplies.

But to do so, policy makers will need to think differently about electricity. While it is a noble instinct of policy makers to want to protect consumers from surprises, from wrong deeds, and from flaws in the market place, it is another thing to want to keep consumers in the dark and to try to intervene to fix things with policy changes whenever prices move in unpleasant directions. Consumers will benefit from knowing the realities of the outlook for electricity supplies, so that they can make their own plans and actions to manage their bills as best they can. Part of helping consumers get there will be for policy makers to adopt policies giving consumers the tools they need — improved information, pricing signals and service provisions that overcome the "invisibility" inherent in today's electricity system. Many of these, in turn, are aided by competitive elements in the industry that allow for real-time pricing, innovation and a customer orientation.

Part of helping consumers is also applying care when adopting "fixes," so that the cure doesn't end up being worse than the disease. For an industry as complex as the electric industry, it seems particularly prudent to allow further evolution in the paths being taken in different parts of the country. This kind of regulatory stability — in the regions with vertically-integrated utilities, and in the regions with more competitive industry structures — will go a long way to providing the environment that will support our shared goals for an efficient, reliable and environmentally acceptable electricity system.

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ENDNOTES

[1] Source: Energy Information Administration ("EIA") "826" data, www.eia.doe.gov/cneaf/electricity/page/sales_revenue.xls

[2] In 2006, 41 percent of retail electricity sales in the U.S. were in states that had restructured their electric industries. EIA, 826 retail sales data (in megawatt-hour ("Mwh")) for 2006, for the following states (and the District of Columbia ("D.C.")), as compared to total retail Mwh sales in the U.S.: Arizona, Connecticut, D.C., Illinois, Maine, Massachusetts, Maryland, Michigan, Montana, New Hampshire, New Jersey, New York, Ohio, Pennsylvania, Rhode Island, Texas, Virginia.

[3] These data are average nominal electricity prices for all customer classes of electricity. Data source: EIA, Form 826 Data (using average annual retail electricity price (cents-per-kilowatthour) for all years except 2007 (for which the data represent the average for the January 2007-April 2007 period).

[4] EIA, http://www.eia.doe.gov/cneaf/electricity/epa/figes1.html .

[5] In recent years, many analysts and scholars have studied the relationship between fossil fuel prices and electricity prices. For example, analyzing several decades of annual price data for natural gas and electricity, MIT's Paul Joskow found that there is a close historical relationship between fuel costs and residential and industrial electricity prices. *See*, Joskow (2006). Young Yoo and Bill Meroney from the staff of the Federal Energy Regulatory Commission found relatively strong explanations for electricity prices increases based on changes in natural gas prices. (Yoo and Meroney (2005), analyzing daily prices in New England (2000 to 2003) and New York (2001-2003).) Ken Rose (2007) observes that natural gas prices have played a role in explaining electricity price changes. Rose states that there are other important factors in explaining prices, including the level of customer load (with high prices reflecting high periods of customer demand for gas and electricity during different seasons, and the existence of different generating technologies (with different power production efficiencies) as well). Greg Basheda et. al. (The Brattle Group), also find that *"Fuel and Purchased Power Cost Increases Have Been Enormous and Are the Largest Cause of Recent Electric Cost Increases.* On an industry-wide basis, our analysis finds that fuel and purchased power costs account for roughly 95 percent of the cost increases experienced by utilities in the last five years. The increases in the cost of these fuels have been unprecedented by historical standards, affecting every major electric industry fuel source." (Basheda et. al., page 2.)

[6] EIA, Coal prices delivered to the power sector. Delivered Price for 1990-2004 from EIA State Data Tables, United States Table 6; for 2005-2006 from June 2007 Electric Power Monthly, Table 4.1.

[7] An actual increase of 65,529 MW occurred from 680,941 MW (in 2000) to 746,470 MW (in 2005). Peak demand in 2007 was expected to be approximately, 760,840 MW in the U.S. Thus, an increase of approximately 80,000 MW was expected from 2000 through 2007. To put that in context, Texas' peak demand in the summer of 2006 was over 62,339 MW. Sources: EIA, Electric Power Annual (2006), Table ES1; North American Electricity Reliability Council, Long-Term Reliability Assessment, 2007, Table 32, ftp://www.nerc.com/pub/sys/all_updl/docs/pubs/LTRA2007.pdf, and NERC, "2007 Summer Assessment: The Reliability of the Bulk Power System in North America" (May 2007), page 11.)

[8] In ERCOT (the electrical system of Texas), summer peak demand was 62,339 MW in 2006. NERC, "2007 Summer Assessment: The Reliability of the Bulk Power System in North America" (May 2007), page 11.

[9] This "one large power plant a week" statement is based on the following: there are 392 weeks from the start of 2000 through July of 2007; Actual net additions of capacity in the US from the end of calendar year 1999 (i.e., the start of 2000) to August 2007 was approximately 210,480 MW. Dividing 210,480 MW by 392 weeks is 536 MW per week, equivalent to a medium-to-large power plant. EIA, Electric Power Annual (2006), Table 2.1 for end of year 1999 (785,927 MW), For capacity in August 2007 (996,410 MW): EIA, Electric Power Monthly, October 2007, Table ES3. New and Planned U.S. Electric Generating Units by Operating Company, Plant and Month, 2007 – 2008. http://www.eia.doe.gov/ cneaf/electricity/epm/epmxlfilees3.xls (accessed 10-21-07).

[10] Because most of this investment was made by non-regulated power companies, the actual investment costs are not publicly available. This rough calculation is based on the following: Assumed capital costs of $550/kW for combined cycle power plants, and $325/kW for combustion turbine power plants. These two technologies accounted for most of the power plant capacity added during calendar years 2000-2007. This capital cost estimates were from RDI's Outlook for Power in North America 1999 Annual Addition (2000). The estimate of capital costs here is based on these numbers, assuming 2/3rd of the capacity added was combined cycle capacity, and the other 1/3rd was combustion turbine capacity. By contrast, more recent estimates of capacity costs are

much higher. For example, 2001 estimates of capital costs were as follows: $616/kW to $800/kW for combined cycles, and CT (2001) of $400/kW to $600/kW for combustion turbines (from Barmack, Kahn, Tierney). A recent estimate of capital costs in 2007 is $800/kW to $1000/kW for combined cycles, and $500/kW to $700/kW (from ISO-NE Scenario Planning Initiative). These more recent capital-cost estimates were not used in this calculation. Sources: EIA, Electric Power Annual 2006, Table ESI; RDI - Outlook for Power in North America - 1999 Annual Edition; Barmack, Kahn, Tierney (2006); http://www.iso-ne.com/committees/comm_wkgrps/othr/sas/mtrls/apr302007/assumptions.pdf; U.S. Electric Energy Market Competition Task Force, Report (2007), page 39.

[11] Smith, Rebecca. "Court Decisions May Aid Some Utility Profits in Long Term." The Wall Street Journal Online. April 3, 2007. Available at: http://online.wsj.com/article/SB117556293661557706.html?mod=US-Business-News. Accessed August 24, 2007.

[12] NERC, "2006 Summer Assessment: The Reliability of the Bulk Power System in North America" (May 2006), page 15. This reflects additions of power lines at 230 kV and higher voltage levels.

[13] Utilities' investments levels were $14.1 billion in 2000, and $15.8 billion in 2003. These figures are for shareholder-owned electric utilities. Edison Electric Institute, http://www.eei.org/industry_issues/energy_infrastructure/transmission/Transmission-Investment-Expenditures.pdf (accessed July 28, 2007).

[14] EIA, Annual Energy Outlook 2007, page 41. As reported in the New York Times, " 'There's massive inflation in copper and nickel and stainless steel and concrete,' said John Krenecki, president and chief executive of GE Energy….'There's real sticker shock out there,' Randy H. Zwirn, president of the Siemens Power Generation Group, said in an interview. He estimated that in the last 18 months, the price of a coal-fired power plant has risen 25 percent to 30 percent. Part of the problem is huge price increases for the raw materials that plants are made from, including copper and nickel, which is what makes steel stainless. But the cost of finishing those commodities into components is also rising. 'There's a lack of production and manufacturing facilities in this country, and that may be partly to blame,' said Jason Makansi, a consultant with Pearl Street, a consulting firm in St. Louis that specializes in electric utilities. But, he said, 'the bigger culprit is the incredible demand in China and the rest of Asia.'…. Siemens, a supplier, gave some examples for a typical combined-cycle natural gas power plant, one that burns the fuel in a gas turbine to drive one generator, then makes steam from the exhaust to drive a second generator. The high-pressure piping for steam, used on a 293-megawatt plant, is up about 60 percent in the last two years, to about $1.12 million, according to the company. The equipment that uses exhaust heat to make steam, used at a 590-megawatt plant, is up about 40 percent in the last two years, $15.1 million in April of this year vs. $10.7 million in May 2005, according to Siemens. Simply moving a 435,000-pound turbine for a 198-megawatt plant from factory to the plant site now runs about $100,000, according to Siemens, up from about $50,000 two years ago." Matthew Wald, "Costs Surge For Building Power Plants," NY Times, July 10, 2007.

[15] EIA, Annual Energy Outlook 2007, page 36.

[16] The U.S. government has recently estimated that average "residential electricity prices are projected to increase by 2.9 percent in 2007 and by a slightly lower rate of 2.4 percent in 2008." EIA, Short Term Energy Outlook – July 2007, page 6. These projections are tied in large part to expected prices for fossil fuel prices, which are expected to remain high in the near term or longer term. According to EIA estimates, long-term electricity prices "follow the prices of fuels to power plants in the reference case, falling initially as fuel prices retreat after the rapid increases of recent years and then rising slowly. From a peak of 8.3 cents per kilowatthour (2005 dollars) in 2006, average delivered electricity prices decline to a low of 7.7 cents per kilowatthour in 2015 and then increase to 8.1 cents per kilowatthour in 2030. In the *AEO2006* reference case, with lower expectations for delivered fuel prices and the added costs of maintaining reliability, electricity prices increased to 7.7 cents per kilowatthour (2005 dollars) in 2030. Without adjustment for inflation, average delivered electricity prices in the *AEO-2007* reference case are projected to reach 13 cents per kilowatthour in 2030." EIA, Annual Energy Outlook 2007, pages 5-6. EIA's long-term price outlook for fossil fuels indicates the following for each fuel: Petroleum: long-term oil prices are likely to remain high, if slightly lower than in the past two years: "from a 2006 average of more than $69 per barrel ($11.56 per million Btu) to just under $50 per barrel ($8.30 per million Btu) in 2014 as new supplies enter the market, then rises slowly to about $59 per barrel ($9.89 per million Btu) in 2030." Natural Gas: "The average U.S. wellhead price for natural gas in the *AEO2007* reference case declines gradually from the current level, as increased drilling brings on new supplies and new import sources become available. The average price falls to just under $5 per thousand cubic feet in 2015 (2005 dollars), then rises gradually to about $6 per thousand cubic feet in 2030 (equivalent to $9.63 per thousand cubic feet in nominal dollars). Imports of liquefied natural gas (LNG), new natural gas production in Alaska, and production from unconventional sources in the lower 48 States are not expected to increase sufficiently to offset the impacts of resource decline and increased demand." Coal: As a result of higher minemouth prices and higher transportation costs for coal, the "average delivered price of coal to power plants is projected to increase from $1.53 per million Btu ($30.83 per short ton) in 2005 to $1.69 per million Btu ($33.52 per short ton) in 2030 in 2005 dollars, 7.0 percent higher than in the *AEO2006* reference case. In

nominal dollars, the average delivered price of coal to power plants is projected to reach $2.72 per million Btu ($53.98 per short ton) in 2030." EIA, Annual Energy Outlook 2007, pages 4-5.

[17] EIA's Annual Energy Outlook (2007) "assumes that, for the purposes of long-term planning in the energy industries, costs will revert to the stable or slightly declining trend of the past 30 years." (page 36). Further, a "total of 258 gigawatts of new capacity is expected between 2006 and 2030, representing a total investment of approximately $412 billion (2005 dollars). If construction costs were 5 to 10 percent higher than assumed in the reference case, the total investment over the period could increase by $21 billion to $41 billion." EIA, Annual Energy Outlook 2007, page 41.

[18] "All told, investment in the transmission system is projected to add more than 7,122 miles of new transmission through 2009, and nearly 12,484 miles added during the 2005-2014 time period….Averaging $14 billion per year over the next 10 years, expected distribution investment is almost triple the size of projected transmission spending." Edison Electric Institute, "New Investments for Transmission and Distribution Systems Are Needed," September 2006.

[19] These are estimates of annual costs to comply with the Clean Air Interstate Rule, the Clean Air Mercury Rule, and the Clean Air Visibility Rule, parts of which begin to go into effect in 2010 with several compliance phases in the subsequent years. These annual costs compare to projected health benefits of approximately $63 to $72 billion in 2010 and $91 to $106 billion in 2015. The net present value of capital investment in pollution controls is estimated to be approximately $19.8, with costs for investment in both pollution controls and generating capacity to make up power production needs totally $23 billion (1999 dollars). (EPA, October 2005), http://www.epa.gov/airmarkets/progsregs/cair/docs/cair_ camr_cavr.pdf, page 30.

[20] Brattle Group, "The Economics of U.S. Climate Policy: Impact on the Electric Industry," prepared in collaboration with FPL Group, March 2007, page 8. Notably, the costs associated with a carbon control program represent a way to internalize into the price of coal-fired power production the costs imposed as a result of burning this cheaper fuel in power plants.

[21] Per-capita consumption of electricity among Americans increased by 13 percent from 1990 to 2003 (the most recent data available). (13242.8 kwh per person per year in 2003, as compared to 11687.2 kwh per person in 1990). Source: Basheda et. al., "Why are Electricity Prices Increasing?" 2007, Appendix A.

[22] It is not hard to overstate the inherent difficulty that exists in studying these issues. Any attempts to assess empirically the impact of restructuring on consumer electricity rates must address a number of issues that complicate such an analysis. "The electric industry" varies for electric utilities within states, across states within regions, and even customer classes within individual utilities. Some states started restructuring under conditions of surplus capacity; others did just the opposite. Some had short-lived rate freezes; other still have them in place. Some allowed for retail customer choice for several years, and then switched gears. Some allow pass-through of fuel costs and expenses on a quarterly basis; others allow such costs to be recovered only if there are extraordinary increases. Some have long-term fuel contracts supporting a significant portion of fuel supply; others have contracts whose prices are indexed continuously to changing prices. Some RTOs have experienced several phases of market design since they began operation; others have just recently started to operate their markets. Even with a single RTO, the changes in market rules over time have created different types and degrees of incentives.

All in all, even if one wanted to conduct a carefully designed study of the effects of fuel prices, or the impact of restructuring, or one or another other factor of interest, it would be difficult at best to do so. Analyses of the performance of restructuring must be careful not to lump together the early and widely recognized failures of the restructuring in California with the more successful development of centralized markets in eastern RTOs. And in the end, it is worth recalling that the initiatives for restructuring the electric industry were largely embarked upon as a way to reduce rates — but to do so relative to what prices would otherwise be in the absence of restructuring. Neither approach to structuring the electric industry — whether traditional regulation or competitive approaches — can assure "lower" rates in absolute terms. There is ample support for that proposition.

Sufficient information exists, also, to encourage thoughtful observers to avoid cherry-picking data points and drawing sweeping generalizations from them. For example, comparisons of rates between 2005 and 2006 do not become a reliable basis for assessments of the success or failure of restructuring, particular when changes in rates between these years reflect the expiration of rate caps that have artificially kept prices below market rates and may well have kept rates below those that consumers would have faced under the traditional cost-of-service models. Similarly, anecdotes reporting dramatic changes in consumer rates may misrepresent the impact of restructuring if they fail to consider the stringency of those caps and the level of rates that would have prevailed had consumers continued to be served by the cost-of-service regulated utilities, or even ignore the reality of significant rate increase in historical periods when large utility investments with cost-overruns began to roll into traditional rates or when significant increases in fuel prices rolled into rates on a dollar-for-dollar basis under fuel-adjustment clauses.

[23] Retail choice commenced in different years in the states that adopted it. For example, several states began retail choice in 1997. The end date April 2007 is the last full calendar month for which data were available as of the writing of this report

[24] Over this period, average retail prices in states that restructured their electric industries rose 30 percent, compared to 26 percent in the states that retained traditional regulation

[25] The RTOs (CAISO, PJM, NYISO, ISO-New England, ERCOT, SPP, and MISO) were actually established in different years after that. The end date April 2007 is the last full calendar month for which data were available as of the writing of this report.

[26] A number of studies have attempted to control for such state-by-state or utility-by-utility differences, and thus provide an estimate of the impact of restructuring holding all of these other factors constant. Joskow, for example, controls for fuel prices, the type of generation technologies relied upon, and average customer size when analyzing consumer rates from 1970 to 2003. (Joskow (2006). Joskow also controls for the average return on utility bonds, which do not vary across states, and the share of electricity generation from facilities that sell their power through terms regulated by the Public Utilities Regulatory Policies Act (or, PURPA).) Joskow found that industry restructuring leads to a 5-to-10-percent decrease in prices to residential customers (and about 5 percent to industrial customers), while wholesale competition leads to a roughly 1-to-0.5-percent reduction in residential prices for each 10-percent increase in power supplied by independent power producers. (Wholesale competition is measured by the share of electricity provided by independent power producers, rather than in relationship to participation in centralized RTO/ISO markets.) Another recent study by Harvey, McConihe, and Pope found that participation in the centralized New York ISO and PJM markets reduced average rates by $0.50 to $1.80 per megawatt-hour. (Harvey, McConihe, and Pope (2006).) These studies, however, represent a starting point, rather than the final word regarding analysis of the impact of electric industry restructuring on consumer rates. Joskow acknowledges that his study is "the first, admittedly crude, empirical analysis to examine more systematically the effects of cost drivers and competitive policy reforms on retail prices across states and over time." (Joskow, 2006, page 28.) The Harvey, McConihe, and Pope study examines only a fraction of market entities (municipal utilities and cooperatives) within two similar RTO/ISO markets (NYISO and PJM). (Harvey, McConihe, and Pope (2006).) Further, several other studies have concluded that restructuring has either increased or had no effect on consumer rates. (Taber et al. (2006) find that deregulation increases prices in certain ISO markets, although the study suffers from a number of methodological and sample issues that make results suspect. Fagan (2006) finds that restructuring did not have a statistically significant impact on price to industrial consumers.) Consequently, despite the many promising signals including demonstrated reductions in costs and reliable statistical analyses finding reductions in consumer rates, further analysis is needed before definitive conclusions can be reached about the impact of restructuring on consumer electricity prices. Even so, these studies provide useful support for the notion that restructuring has not been the spoiler often pointed to by its critics.

[27] Data reflect prices as the end of 2006 (2006 data from EIA, Form 876 data)

[28] In 1996, the 19 states (including DC) with above-average electricity rates were (in order, from highest to lowest): Hawaii, New Hampshire, New York, Connecticut, New Jersey, Rhode Island, Alaska, Massachusetts, Vermont, California, Maine, Pennsylvania, Illinois, Arizona, DC, Florida, Michigan, Maryland, and Delaware. In 2006, the higher-than-average-priced states included all of those states (except Pennsylvania, Illinois, Arizona, and Michigan), as well as Texas and Nevada. Note that two high-priced states in 1996 and that restructured their electric industries after then were Pennsylvania and Illinois; both of these were still under rate caps at the end of 2006, and had relatively low rates at the end of 2006. All of the high-priced states except Hawaii and Alaska, Florida, and Delaware restructured their electric industries during the past decade. Note that two high-priced states in 1996 and that restructured their electric industries after then were Pennsylvania and Illinois; both of these were still under rate caps at the end of 2006, and had relatively low rates at the end of 2006. 1996 and 2006 data from EIA, Form 876 data.

[29] Except Hawaii, Alaska, Florida, and Delaware.

[30] Texas, Ohio, Montana, and Virginia also restructured their electric industries.

[31] These percentages are calculated as the ratio of the average price in restructured states to the average electricity price in non-restructured states. Restructured states were considered to be: Arizona, Connecticut,

District of Columbia, Illinois, Maryland, Maine, Massachusetts, Michigan, Montana, New Hampshire, New Jersey, New York, Ohio, Pennsylvania, Rhode Island, Texas, and Virginia. Data are from EIA, Form 876 data.

[32] This trend has also been observed in the research carried out by Howard Axelrod, David DeRamus and Collin Cain and published in "The Fallacy of High Prices," *Public Utilities Fortnightly* (November 2006), page 59: "Perhaps even more interesting has been the effect of competition on regional price differentials. While a number of important factors — including fuel mix, labor costs, taxes, and cost of living — drive regional electricity prices, the gap between the PJM area, traditionally a high-cost area, and the Southeast, traditionally a low-cost area, has been shrinking. Our research shows that retail rates in five Southeastern states [footnote in original] rose 23.7 percent from 1998 to 2005, while rates in four "classic" PJM states [footnote in original] rose only 7.8 percent over that same period.[footnote in original] The 7.8 percent increase for the PJM states reflects continued rate caps for some customers in 2005, but the corresponding increase for New Jersey, which has had retail electricity rates set competitively since 2003,was just 9.6percent (*see Fig. 3*). There are limits to how far one can extend such a comparative analysis of rates across different regions of the country. … For example, the state of Maryland recently was engulfed in a significant political controversy when bids to provide standard-offer service to Baltimore Gas & Electric (BG&E) residential customers were 72 percent higher than the then current retail rates, which had been frozen since 1999 at a 6.5 percent discount to rates in effect since 1993. Obviously, if one were to compare Maryland's retail electric prices with prices in the Pacific Northwest (PNW), one would observe that PNW retail prices are significantly lower. Does that prove that there are not any benefits from competition? The answer is clearly no, since prices in the PNW reflect abundant, federally subsidized hydroelectric capacity not available in Maryland, which makes direct price comparisons between the two regions irrelevant and misleading. To account for the difficulties inherent in a cross-regional comparison, we performed an econometric analysis of the effects of competition over a broad cross-section of the United States, using data for the years 1980 through 2004 for all states east of the Mississippi to estimate the effects of wholesale competition and state restructuring on the retail cost of electricity. We controlled for a number of factors influencing electricity prices, including generation mix, concentration of independent power producers, and capital costs. This specification of an econometric model allows us to derive a preliminary estimate of the benefits of wholesale competition and retail access, controlling for differences in fuel mix and other factors. Again, it is our view that a more robust estimate of the benefits of competition will require additional time, as many of the benefits of competition are inherently long-term in nature. Nevertheless, despite the relatively short time period since electricity restructuring was implemented, our econometric analysis indicates that the introduction of wholesale competition has resulted in an average reduction in the price of electricity by $6.50/MWh for all retail customers. Considering Maryland alone, as the state in which recent price increases arguably have caused the most political controversy, our analysis shows that the benefits of wholesale competition to Maryland consumers are more than $300 million per year."

[33] Many observers have commented on the fact that states adopted a complex and often internally inconsistent packages of policies when they adopted as part of the "restructuring" package, with some of these policies – such as multi-year retail rate freezes established at levels below prevailing prices in markets – inhibiting the ability of competitive retail markets to develop over time. On the other hand, such policies were part of the political bargains made to assure decision makers that there would be benefits for all consumers associated with adoption of policies to restructure the industry. See, for example, Ashley Brown, "Retail Procurement: Default Service vs. Monopoly Service Considerations," Presentation to Harvard Electricity Policy Group, October 5, 2007.

[34] See, for example, the November 2005 letter from seven companies (including Federated Department Stores, WalMart, 7-Eleven, and JC Penny) representing nearly 14,000 facilities and over $2 billion in annual electricity costs as commercial consumers of electricity. http://www.competecoalition.com/1115comments.pdf

[3535] The U.S. Electric Energy Market Competition Task Force's Report to Congress on Competition in Wholesale and Retail Markets for Electric Energy (April 2007) provides a good summary of the difficulties experienced in many "retail choice" states in implementing workable competitive markets for small electricity customers.

[36] By comparison, under traditional regulation utilities typically do not share in any of the financial gains from improved operating efficiencies. Under cost-of-service regulation, utilities generally recover their operating expenses but are not allowed to share in the savings they might create by increasing operating efficiency to reduce fuel costs or reducing other components of costs. While utilities might be able to share in some savings under certain circumstances (e.g., incentive regulation or due to lags between regulatory proceedings), the fact that savings are shared and often transitory create only partial incentives for utilities to undertake actions to improve plant productivity. Incentive regulation, which allows regulated utilities to share in the savings produced when plants exceed pre-determined performance benchmarks, creates similar incentives to those created by plant divestment. Lags between regulatory proceedings may allow regulated utilities to profit from cost savings until they are incorporated into rates in future periods.)

[37] One of the techniques used in many states to enhance such incentives for competition was divestiture of power plants, which in some cases allowed for firms to specialize in the operation of particular types of facilities (such as nuclear plant operations).

[38] Bushnell and Wolfram (2005).

[39] Global Energy Decisions (2005); Barmack, Kahn, and Tierney (2006). *See*, also, Cain and Lesser (2007), who found a 5- percent improvement in nuclear output, with a total efficiency benefit in PJM East's region of approximately $450 million in annual savings.

[40] Fabrizio, Rose and Wolfram (2006). *See*, also, Shanefelter (2006). For example, one study estimated improvements in fossil-fuel plant efficiency of roughly 2 percent, while another study found reductions in labor and operations costs of 3 to 5 percent. (Bushnell and Wolfram (2006) estimate approximately a 2 percent improvement in plant heat rates, which Wolfram (2003) estimates would generate savings of roughly $3.5 billion annually. Fabrizio, Rose and Wolfram (2006) estimate a 3 to 5 percent reduction in labor and operations costs, which, based on estimates provided by Wolfram (2003), would produce savings of at least $1 billion annually.) Improvements in the operation of nuclear facilities — where availability and output are estimated to have increased by 10 percent — appear to be largely the result of such consolidation. Although these improvements may not appear dramatic, when aggregated across all facilities, the combined annual savings could be in the billions of dollars.

[41] For example, Tierney and Kahn (2007) estimate the savings from increased plant availability in addition along with savings from other elements of restructuring, such as the consolidation of the multiple geographic areas that had previously used for economic plant dispatch.

[42] Restructuring has facilitated geographic consolidation in a number of ways. One is through the integration of dispatch (or, "unit commitment") decisions that had previously been made within individual sub-regions, such the integration of New York Power Pool sub-regions into the New York ISO. Geographic consolidation also includes integration of regions that were previously in separate RTO/ISOs or dispatch zones, such as the formation of PJM and the recent integration of American Electric Power ("AEP"), Commonwealth Edison ("ComEd"), and Dayton Power and Light ("DPL").

[43] Tierney and Kahn (2007).

[44] Global Economic Decisions (2005). The $85 million annual savings reflects savings across the entire Eastern Interconnect, which spans the majority of the eastern and mid-west states.

[45] For example, Souce: ISO-NE, Capacity Energy Loads and Transmission Reports ("CELT" Reports) for each year from 1999 through 2006. Capacity data in the table in SECTION I - Summaries Summer - NEPOOL and Total New England August Capabilities and Summer Peak Load Forecast (MW).

[46] http://www.pjm.com/contributions/news-releases/2007/20080810-demand-response-record.pdf

[47] See Electric Energy Market Competition Task Force, Appendix C. "The Task Force reviewed roughly 30 cost-benefit analyses [of electric industry restructuring developments] in an attempt to better understand what they reveal. Based on this review, together with a review of the recent DOE Report (J. Eto, B. Lesieutre, and D. Hale, "A Review of Recent RTO Benefit-Cost Studies: Toward More Comprehensive Assessments of FERC Electricity Restructuring Policies" (December 2005) [hereinafter Eto]), the Task Force has made the following observations: (1) Many of the existing studies address only the benefits of restructuring proposals. ...(2) The benefits associated with some of the most significant motivations behind restructuring — the maintenance of system reliability and the facilitation of lowest-cost electricity production (via incentives for innovation and low-cost construction) - are very difficult to quantify using current technology and are often left out of benefit assessments. "It is important that technically limited studies not be interpreted to suggest that impacts that they do not analyze are not significant." Eto at 21. (3) Existing methods and models used to estimate benefits are limited in what they can measure. ...(4) Modeling energy transmission and markets necessarily requires making a great deal of assumptions given the significant limitations in data needed to "feed" these models. Thus, outputs of RTO modeling attempts vary widely based on the assumptions made by the parties doing the modeling — assumptions as to transmission configurations, weather, imports/exports, market behaviors, generation costs, etc. ...(5) Another limitation of the studies is that they often only estimate the benefits to society as a whole. Determining the distribution of benefits and costs - who wins and who loses, or who wins the most - is an important piece of the decision making puzzle. Unfortunately, it is much more difficult to measure the distribution of benefits than it is total social costs. ...(6) Characteristics of the best restructuring cost-benefit studies, given existing technology/data, include: Provision of clear and precise descriptions of assumptions, data sources, methods and technical detail; Where econometric models are used, study write-ups should provide regression methods and equations, goodness of fit measures,

and results of any tests done to detect analytical flaws; An attempt to address all potential costs and benefits; An effort to address the distribution of impacts."

See also the analysis of John Kwoka, "Restructuring the U.S. Electric Power Sector: A Review of Recent Studies," Prepared for the American Public Power Association, November 2006.

[48] Tabors Caramanis & Associates. "RTO West Benefit/Cost Study: Final Report Presented to RTO West Filing Utilities. March 11, 2002.

[49] See ISO/RTO Council, "The Value of Independent Regional Grid Operators," November 2005. The report states on page 37 that "Thus, industry average costs per MWh have been fl at since 2003." The data for the individual ISO/RTOs are shown in Appendix A, which states that "Figure A-1 shows ISO/RTO costs as a function of revenue requirement per unit of load served. This shows that while per-unit costs increased in the early years as each ISO/RTO began building its capabilities and experience, those costs have leveled off or dropped as the organizations and their offerings are stabilizing. It also shows a marked distinction between the ISOs and RTOs serving relatively smaller footprints and loads (New England, New York and California) relative to those providing grid and market services to large footprints and loads (ERCOT, Midwest ISO and PJM)." Page 43.

[50] In a recent report exploring different methods for monitoring wholesale power market monitoring in the Western Interconnection outside of California and Alberta, the authors noted the following: "By market monitoring, we mean the systematic analysis of market behavior and outcomes to identify behavior that is inconsistent with well-functioning competitive markets. Such behavior may include the exercise of market power, e.g., withholding supply from the market in order to raise price. [footnote in the original] In the U.S., Regional Transmission Organizations (RTOs) with "Day 2" functions [footnote in the original] generally have dedicated market monitoring functions. The market monitors may be RTO staff members, independent consultants, or both. The Federal Energy Regulatory Commission (FERC) treats applications to sell at market-based rates from suppliers in markets with the full complement of "Day 2" functions, including formal market monitoring, more leniently than other applications. [footnote in the original] While we fully acknowledge the wide range of views on the costs and benefits of RTOs, it is simply a fact that market monitoring in RTOs is easier—primarily because of the voluminous amounts of data produced in the centralized "Day 2" markets administered by RTOs. RTO market monitors typically have access to data on the hourly operations of individual units, their bids into various centrally administered, bid-based markets —including markets for both energy and ancillary services, estimates of units' variable costs, hourly prices at multiple locations and for multiple products, detailed information on transmission constraints, and other data not typically available in non-Day 2 RTOs and other bilateral markets, such as exist in the Western United States. Because of the absence of publicly and/or centrally collected data for the Western U.S. wholesale power markets outside of California, it is generally infeasible to replicate the analyses performed by market monitors in Day 2 RTOs. [footnote in the original] Therefore, it is necessary to approach market monitoring in a different way than has been done in organized markets." This particular article examines, among other methods, the use of econometric models to assist in informing observers about the performance of wholesale markets in the West. See, Matthew Barmack, et. al (2006) "A Regional Approach to Market Monitoring in the West," Lawrence Berkeley National Laboratory (October 2006), page 1.

[51] Energy Policy Act of 2005, Section 1815.

[52] Electric Energy Market Competition Task Force, "Report to Congress on Competition in Wholesale and Retail Markets for Electric Energy, Pursuant to Section 1815 of the Energy Policy Act of 2005," April 2007, page 92.

[53] See, for example, the November 2005 letter from seven companies (including Federated Department Stores, WalMart, 7-Eleven, and JC Penny) representing nearly 14,000 facilities and over $2 billion in annual electricity costs as commercial consumers of electricity. http://www.competecoalition.com/1115comments.pdf Another anecdotal example can be found in a recent presentation by a provider of "total energy management" services (Enernoch) who recently listed its customers as including such companies as Xerox, Kraft, Corning, Dresser-Rand, SBC, Pitney Power, Level 3 Communications, GE, AT&T, Adobe, Tufts, MIT, Albertsons, Stop LL& Shop, Big Y, Price Chopper, Partners Health Car, Pfizer, Westin Hotels, Marriott Hotels, Sheraton Hotels, Hampton Inn and Suites, Hilton Hotels, and a wide variety of cities, towns and state governments. Tim Healy, Enernoch, "Demand Response: An Underutilized Capacity Resource Whose Time is Now," presentation to the Harvard Electricity Policy Group, *March 2, 2006,* http://www.ksg.harvard.edu/hepg/Papers/Healy_Demand_Response_0306.pdf

[54] As of 1991, 91 percent of U.S. power was produced at plants owned by regulated electric utilities. By contrast, between 1996 and 2004, roughly 74 percent of electricity capacity additions were made by non-utility power producers. Electric Energy Market Competition Task Force Report, page 35.

[55] Electric Energy Market Competition Task Force Report, page 35.

[56] Electric Energy Market Competition Task Force Report, page 35.

[57] One study of a region (New England) with a substantial post-2000 investment boom compared system power production and investment costs against a counterfactual scenario in which such capacity surplus had not occurred (i.e., under a supposed case in which traditional regulation had occurred). The study estimated that the addition of the more efficient generating capacity in New England produced modest long-term system benefits for the region, and at-least short-term transfers of benefits from investors to consumers. Barmack, Kahn, Tierney (2006).

[58] Edward Bodmer, "The Electric Honeypot: The Profitability of Deregulated Electric Generation Companies," prepared for APPA (January 2007).

[59] Mirant Corporation declared bankruptcy in 2003 (See Mirant Corporation 10-K For the Fiscal Year Ended December 31, 2003). NEGT (formerly PG&E NEG) filed for Chapter 11 bankruptcy protection on July 8, 2003 (See PG&E Corporation 10-K For the Fiscal Year Ended December 31, 2003). On May 14, 2003 NRG and 25 direct and indirect wholly-owned subsidiaries commenced voluntary petitions under chapter 11 of the US bankruptcy code (See NRG Energy, Inc. 10-K For the Fiscal Year Ended December 31, 2003). Calpine filed for bankruptcy protection in December 2005. (http://www.cfo.com/article.cfm/5347314, accessed August 25, 2007.) AES Corp had its credit rating downgraded by Moody's from Baaa3 to Ba1 on May 26, 1999, from Ba1 to Ba3 on June 27, 2002, and from Ba3 to B3 on October 11, 2002. Standard and Poor's downgraded AES Corp from BB to BB- on June 6, 2002 and from BB- to B+ on October 3, 2002. AES Corp's credit ratings have subsequently increased from both rating agencies. (Source: Bloomberg, accessed on August 24, 2007)

[60] For example, NRG emerged from bankruptcy on December 5, 2003. The company now states that it has "a significant presence in major competitive power markets in the United States" and that it plans to "maintain and enhance the Company's position as a leading wholesale power generation company in the United States." (See NRG Energy, Inc. 10-K For Fiscal Year Ended December 31, 2006)

[61] This is a back-of-the-envelope calculation based on the EIA estimate of $412 billion estimated to be needed for new power generation investment (between 2006 and 2030), the $14 billion per year expected for distribution systems ("triple the size of projected transmission spending"), and the scores of billions of dollars of investment in pollution control costs associated with existing federal air regulations. See the discussion and references in the section above titled "1. Electricity is not too cheap to meter."

[62] See, for example, the recent paper by Lester Lave et al., "Deregulation/Restructuring, Where Should We Go from Here?" (7-18-07), and Paul Joskow, Prepared Remarks before the FERC, Conference on Competition In Wholesale Power Markets, Docket No. AD07-7-000 (February 27, 2007). See also, the separate comments of Linda G. Stuntz, John Rowe/Elizabeth Moler, presented to the FERC Conference on Competition in Wholesale Markets, Docket No. AD07-7-000, February 27, 2007.

[63] Saying that power markets are not perfect is different from saying that they are fundamentally flawed. As observed by Paul Joskow of MIT in February 2007, "The markets in the Northeast and Midwest organized around an LMP model and managed by an Independent System Operator (ISO) now work very well in almost all dimensions. These markets are extremely competitive under almost all contingencies. The wise use of independent market monitors and thoughtful market power mitigation mechanisms have largely mitigated potential market power problems when the few remaining contingencies arise. No market is textbook perfectly competitive and it is unreasonable to set that goal as a standard for wholesale electricity markets to meet." Paul Joskow, Prepared Remarks before the FERC, Conference on Competition In Wholesale Power Markets, Docket No. AD07-7-000 (February 27, 2007). Additionally, pursuant to FERC requirements (and state requirements in the case of ERCOT), the various RTOs have market monitors to watch and evaluate the performance of markets, to screen conditions and look for anomalous behavior or pricing outcomes, and to flag problems for regulatory investigation when problems are detected, and to screen conditions. Tierney and Hibbard, Market Monitoring at U.S. RTOs: A Structural Review, March 2007.

[64] See, for example, FERC Order 890, 18 CFR Parts 35 and 37 (Docket Nos. RM05-17-000 and RM05-25-000; Order No. 890) Preventing Undue Discrimination and Preference in Transmission Service (Issued February 16, 2007); and FERC's Advanced Notice of Proposed Rulemaking, "Wholesale Competition in Regions with Organized Electric Markets, AD07-7-000 (Item E-3), dated June 21, 2007.

[65] This list of suggestions is based on a variety of sources, including comments made by participants at FERC conferences on wholesale market performance. See, for example the comments of John Shelk of the Electric Power Supply Association (http://www.ferc.gov/EventCalendar/Files/20070228110115-Shelk,%20EPSA.pdf.), William Massey of Covington & Burling (http://www.ferc.gov/EventCalendar/Files/20070314144339-Massey,%20Covington%20&%20 Burling.pdf.), John Rowe and Elizabeth Moler of Exelon (http://www.ferc.gov/EventCalendar/Files/20070227090732-Moler%20and%20Rowe,%20Exelon.pdf), and Paul

Joskow of MIT (http://www.ferc.gov/EventCalendar/Files/ 20070228090000-Joskow,%20MIT.pdf). (All accessed August 25, 2007).

[66] See comments of Linda G. Stuntz, at FERC Conference on Competition in Wholesale Markets, Docket No. AD07-7-000, February 27, 2007. See also Baldick, et. al. (2007), "A National Perspective on Allocating the Costs of New Transmission Investment: Practice and Principles."

[67] And doing so would be consistent with the decades-old advice of Professor James Bonbright — often considered one of the "grandfathers" of principles of regulation of utilities — that the purpose of regulation is to replicate the results that the competitive market system would achieve in the way of reasonable prices and profits: "Regulation, it is said, is a substitute for competition. Hence its objective should be to compel a regulated enterprise, despite its possession of complete or partial monopoly, to charges rates approximating those which it would charge if free from regulation but subject to the market forces of competition. In short, regulation should be not only a substitute for competition, but a closely imitative substitute." See James Bonbright (1966) page 3, as quoted in Roger A. Morin, Ph.D., *New Regulatory Finance,* Public Utilities Reports, Inc., 2006 (page 1).

[68] One demand-response provider company, Enernoc, indicated in 2006 that its customers for "total energy management" programs include a "who's who" of large industrial firms, commercial office buildings, educational, groceries, department stores, health care facilities, hospitality and other light industrial facilities. See http://www.ksg.harvard.edu/hepg/Papers/Healy_Demand_Response_0306.pdf

[69] David Lawrence, "NYISO's Demand Response Programs," Presentation to the New York Market Operating Committee, 2007, http://www.nyiso.com/public/webdocs/services/market_training/workshops_courses/nymoc/demand_response 0507.pdf

[70] http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/dr_wkgrp/mtrls/2007/aug12007/intro_dr_working_ group _meeting_08_01_2007.ppt#280,3,Demand Response (as of August 1, 2007).

[71] http://www.iso-ne.com/committees/comm_wkgrps/othr/sas/mtrls/elec_report/scenario_analysis_final.pdf, page 4.

[72] See, for example, the study of the Community Energy Cooperative (of the Center for Neighborhood Technology) which calculated that as more customer loads participate in demand-response programs, the savings to other, non-participating programs increase as well, due to reduction in wholesale market prices and price volatility, avoidance of electric utility costs, and mitigation of market power. Anthony Star, "Can Real-Time Pricing Be The Real Deal?", presentation to the Harvard Electricity Policy Group, Community Energy Cooperative, March 15, 2007. http://www.ksg.harvard.edu/hepg/Papers/star_demand_31507.pdf