# COMMENTS
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A16

COMPETE

Electricity Competition Drives Innovation and Consumer Benefits

# CUSTOMER CHOICE IN ELECTRICITY MARKETS: FROM NOVEL TO NORMAL

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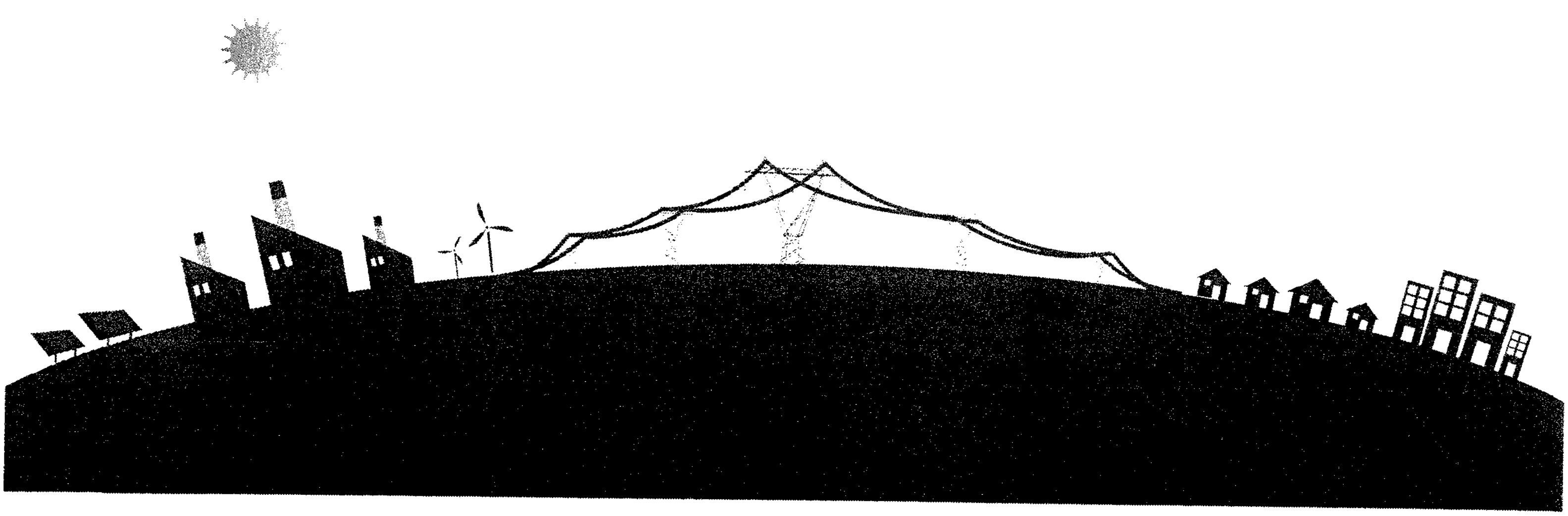
November 15, 2010



# CUSTOMER CHOICE IN ELECTRICITY MARKETS: FROM NOVEL TO NORMAL

*All truth passes through three stages. First, it is ridiculed. Second, it is violently opposed. Third, it is accepted as being self-evident.*
Arthur Schopenhauer [1]

## CUSTOMERS ACT WHILE THE DEBATE CONTINUES

The policy debate over opening state-regulated retail electricity markets to competition is more than two decades old.[2] Yet with a full decade of broadly based customer choice experience there remains an active debate over the wisdom of ending enforced monopoly in electricity supply. Similar debates have largely been put to bed for other formerly price-regulated industries.

As it was with natural gas and telecommunications, in electricity it is customers who are leading the way, insisting on and exercising the opportunity to choose a competitive supplier even as the debate in policy circles persists.

The prolonged debate over electricity market reform can be blamed in great part on the long shadow cast by the California experience in 2000 and 2001. California's "experiment" with customer choice was saddled with a deeply flawed market design that failed to require or allow utilities to properly hedge their electricity supply costs. Forcing utilities to rely mainly on the day-ahead market in the early stages of customer choice to meet their obligations paved the way for failure. It was not so much a market failure as a regulatory failure that deterred other states from enacting retail choice policies or from proceeding to implement previously passed laws. This occurred even though the market design flaw that contributed to California's fiasco was avoided in all the other states that soldiered on with retail competitive reforms. Those states had guarded against incorporating the California flaw, assuring flexibility and options for risk management.[3]

Today, retail customer choice in electricity is no longer an experiment - no longer a novelty. In 16 states and the District of Columbia, jurisdictions that account for over 40% of all electricity consumption in the continental United States,[4] customer electricity choice is well established and widely accepted.

Even as the policy debate has continued over opening retail electricity to competition, millions of customers are opting for electricity choice and dramatically changing the facts on the ground.

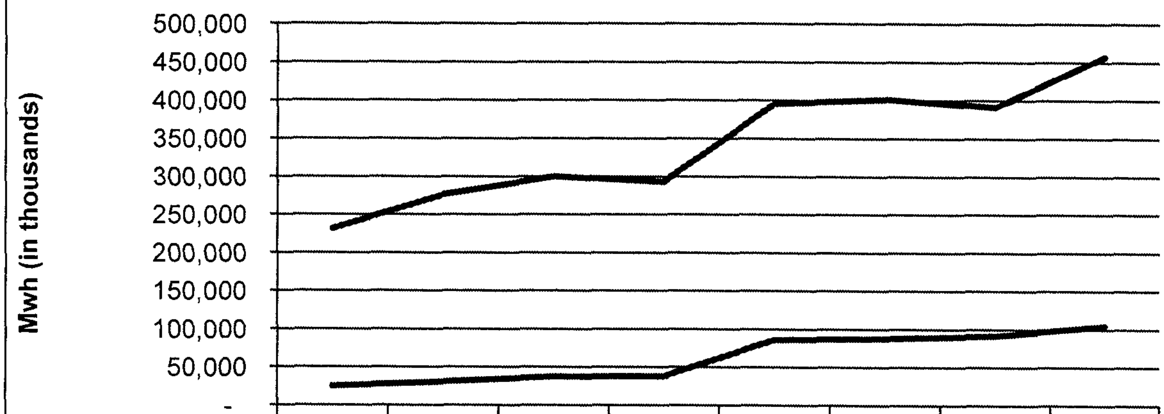
- Competitive volumes and accounts continue to increase, with nearly 9 million residential customers and over 1.8 million business and government customers exercising electricity choice in the 17 jurisdictions.
- Most jurisdictions that have elected competitive retail models have continued to move ahead, leading to a doubling of competitively served volumes between 2003 and 2010; and
- There is a growing awareness and understanding that electricity choice effectively accommodates and complements demand response, energy efficiency, integration of renewable resources and the emergence of the Smart Grid.

Meanwhile, outside the United States, developed economies around the world have been moving ahead with competitive restructuring and customer choice, including Canada, the European Union and United Kingdom, Australia, New Zealand, and parts of South America.[5] Restructuring policies that support retail choice are sustained because retail choice has satisfied customers, delivered efficiency benefits and provided a supportive framework for an intelligent grid that integrates our energy use with environmental improvement and sustainability.

**Chart 1:**
**U.S. Competitive Retail Power Accounts**
**2003-2010**


| | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | Q2 2010 |
|---|---|---|---|---|---|---|---|---|
| Residential | 2,309 | 2,587 | 2,838 | 2,809 | 6,777 | 7,111 | 7,547 | 8,791 |
| Non-Residential | 473 | 595 | 728 | 778 | 1,554 | 1,583 | 1,587 | 1,843 |

**Chart 2:**
**U.S. Competitive Sales Volume (MWH)**
**2003-2010**



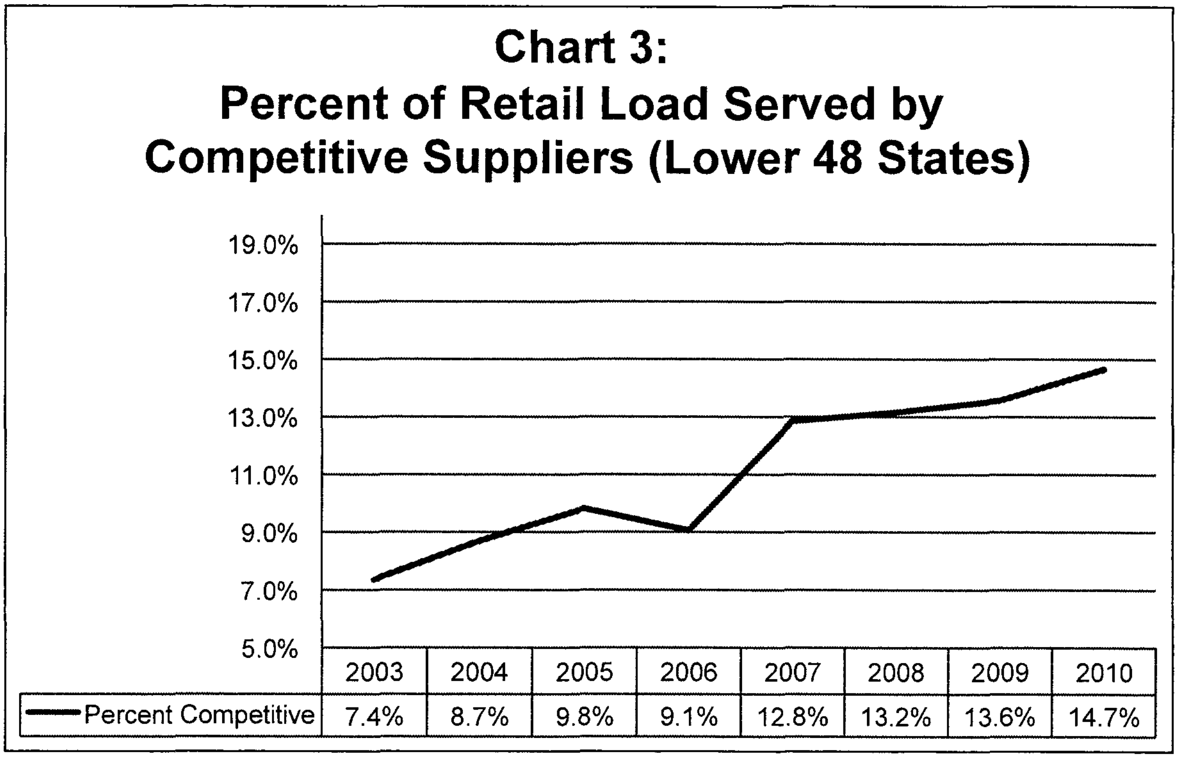

| | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | Q2 2010 |
|---|---|---|---|---|---|---|---|---|
| Non-Residential | 230,961 | 276,131 | 300,018 | 293,122 | 395,662 | 401,272 | 391,232 | 457,258 |
| Residential | 24,802 | 30,876 | 37,541 | 37,771 | 85,877 | 87,749 | 91,282 | 104,395 |

## THE CUSTOMER CHOICE SURGE

By the middle of 2010, more than 1.8 million commercial and industrial (C&I) accounts in states with competitive markets were buying electricity from competitive suppliers under bilateral contracts, reports KEMA, the leading firm in collecting data on the competitive retail electricity market.[7] Nearly 9 million residential customers were buying power from suppliers other than the traditional utility (Chart 1).[8] KEMA's figures suggest national growth rates in the number of customer accounts from 2009 to mid-2010 at 17% for C&I accounts and 17.2% for residential customers.

KEMA's statistics suggest a growth rate in estimated annualized competitive sales volume between 2009 and 2010 of 16.9% in the C&I sector and 14.4% for residential customers. KEMA estimates 2010 annualized demand for competitive C&I customers at nearly 460 million megawatt hours (MWh) for residential customers over 100 million MWh (Chart 2), for a total of 560 million MWH.

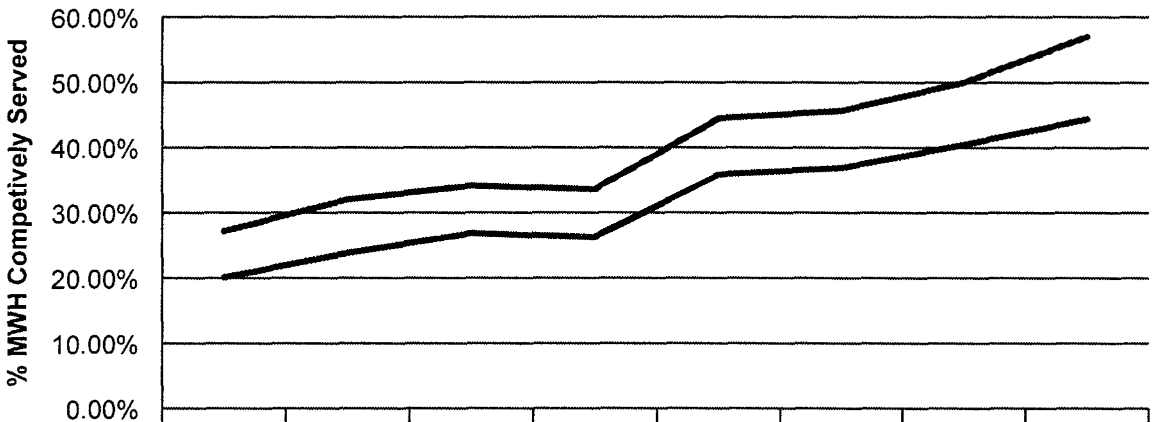
This aggregate annual demand of 560 million MWh represents almost 15% of electricity consumption in the lower 48 states (Chart 3). This is a doubling since 2003 of the share of total continental U.S. electricity sales volume accounted for by non-utility energy suppliers.




| Year | Lower 48 Total MWH (000's) | Competitive MWH (000's) | Percent Competitively Served |
|---|---|---|---|
| 2003 | 3,477,779 | 255,763 | 7.4% |
| 2004 | 3,530,959 | 307,007 | 8.7% |
| 2005 | 3,644,517 | 357,559 | 9.8% |
| 2006 | 3,653,169 | 330,893 | 9.1% |
| 2007 | 3,747,649 | 481,539 | 12.8% |
| 2008 | 3,715,647 | 489,020 | 13.2% |
| 2009 | 3,559,441* | 482,831* | 13.6% |
| 2010 | 3,708,938* | 543,797* | 14.7% |

The growth of the competitive share of national sales volumes from zero to 15% in the past decade understates the case. While more than one out of 7 MWh nationally is served competitively at retail, competitive providers are currently supplying more than 44% of eligible demand in the 17 competitive jurisdictions, having doubled from about 20% in 2003. Further, in the customer choice jurisdictions a majority of all eligible non-residential is served competitively, having more than doubled from 27% in 2003 to 57% in 2010 (Chart 4). The reality is that when given the opportunity to switch to competitive suppliers, customers do so in great numbers. They are seeking innovative energy products and solutions as they contribute to forging a more efficient market for everyone else as well.

**Chart 4:**
**Percent Retail Load Served Competitively**
**17 Competitive Jurisdictions**




| | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
|---|---|---|---|---|---|---|---|---|
| C&I | 27.18% | 32.02% | 34.13% | 33.59% | 44.47% | 45.63% | 49.99% | 57.01% |
| Total | 20.12% | 23.79% | 26.81% | 26.24% | 35.88% | 36.90% | 40.46% | 44.38% |

## CUSTOMERS SWITCH – FOR THE BENEFITS OF A COMPETITIVE MARKET

Much of the switching by customers to competitive providers over the past decade has been an unabashed search for energy cost savings. Larger customers led the way as factories, hospitals, schools, government facilities, office buildings and transit systems moved to reduce their operating costs. More recently, residential customers and small businesses have found savings opportunities. Competitive transition periods and utility default service options are now largely priced through market-based procurement processes, which has helped ensure a level playing field for comparison shopping, thus facilitating the analysis of retail choice alternatives.

The price distortion and cross-subsidies characteristics of traditional ratemaking are being left behind. After a decade of rapid development, customer choice is emerging as much more than an opportunity for lower kilowatt-hour prices. Customer choice is becoming the vehicle for customers to tailor supply and pricing contracts to their operating requirements and existing or desired usage patterns, replacing traditional regulated utility supply offerings that were "one-size-fits-all" tariffs customers were obliged to accept. Monopoly bureaucracies can never match the creativity and alacrity of customers and entrepreneurs interacting with one another.

Today, customer choice and supplier competition are delivering more accurate price signals – information of enormous value to customers, suppliers and policy makers alike. A large number of competitive suppliers are continually offering price information to customers and racing to design products based on feedback from customers.

A growing number of competitive suppliers, now on the order of a hundred or more, are operating across the nation's competitive jurisdictions. Some market exclusively to C&I customers or to residential and small business customers. Some operate in just a single state or on a regional basis while others have qualified for licenses in all or most competitive jurisdictions. Vigorously competing with one another, these suppliers offer a range of products that are constantly being refined and improved through the give and take between buyers and sellers routine in the rest of the economy.[9]

## CHOICE STORIES

If the proof of the pudding is in the eating, then the proof of electricity choice is in the choosing. What do customers do when given the opportunity to choose their electricity suppliers and what do they do once they have experienced the results of choosing their suppliers? The answer is found by looking at customer choice in individual states and within the utility delivery systems in those states.

A wide variety of competitive choice implementation strategies and timetables are represented in jurisdictions that have pursued industry restructuring. Some have achieved high levels of competitive choice among both the C&I and residential customers while others have seen competition primarily in the non-residential market. However, there is always the expected pattern seen in other liberalizing industries of larger customers being first movers.

Start-up problems, inexperience, regulatory uncertainties and sometimes incumbent resistance are gradually overcome by customer interest in competitive alternatives. The creativity of new entrants in devising and pricing products provides benefits that are attractive to customers. As the competitive market achieves widespread acceptance among larger customers, skepticism on the part of regulators and policy makers is assuaged, paving the way for smaller customers to pursue competitive choice.

As the retail choice market develops in a jurisdiction, the products and services desired by customers gradually become more diverse, moving beyond merely a discount to the utility tariff product. There are fixed-price products, both for the energy commodity and electricity bundled with load-following delivery. Other contracts provide a mix of fixed price supply and daily, hourly or other index-priced energy. Customers can take advantage of demand response programs offered through competitive wholesale markets and regional transmission organizations.

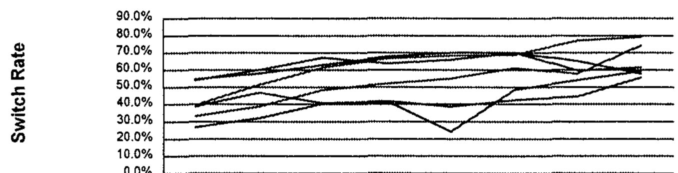
With clear price signals comes a more refined ability of customers to commit the capital and effort necessary for more efficient utilization of energy, resulting in cost savings and environmental benefits. No longer is product and rate design dictated by the seller or the regulator.

### New York

New York has implemented customer choice as successfully as any other state, doing so without a general restructuring law. The New York Public Service Commission (NYPSC) moved utility-by-utility to restructure the industry along competitive lines as it directed extensive divestment of generation and customer access to alternative suppliers.

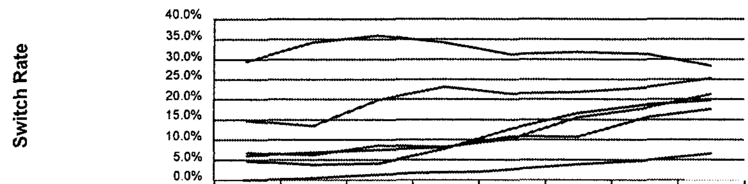
Retail competitive choice is now the predominant form of service across utilities in the Empire State's C&I sector (Chart 5). On a statewide weighted basis, two-thirds of eligible C&I electricity demand is currently being served competitively and a majority of that demand was served competitively as far back as 2003. Since 2008, the share of residential demand served competitively has generally trended upward, with about a fifth of all residential demand now being served competitively (Chart 6).

**Chart 5:**
**NY: Non-Residential Switch Rates: 2003-2010**




| | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2Q 2010 |
|---|---|---|---|---|---|---|---|---|
| Central Hudson Gas & Elec Corp | 26.8% | 32.0% | 40.4% | 41.4% | 24.2% | 48.4% | 54.1% | 59.2% |
| Consolidated Edison Co-NY Inc | 54.6% | 57.9% | 63.0% | 67.8% | 70.1% | 70.3% | 59.6% | 61.4% |
| New York State Elec & Gas Corp | 33.3% | 38.8% | 48.4% | 51.9% | 55.0% | 61.1% | 57.8% | 74.4% |
| Niagara Mohawk Power Corp | 54.0% | 60.0% | 67.3% | 63.7% | 66.0% | 70.1% | 65.2% | 57.7% |
| Orange & Rockland Utils Inc | 38.7% | 46.7% | 40.6% | 41.7% | 38.5% | 42.5% | 44.6% | 55.6% |
| Rochester Gas & Electric Corp | 39.5% | 51.2% | 61.5% | 66.6% | 68.5% | 68.9% | 77.2% | 79.1% |

**Chart 6:**
**NY: Residential Switch Rates: 2003-2010**




| | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2Q 2010 |
|---|---|---|---|---|---|---|---|---|
| Central Hudson Gas & Elec Corp | 0.0% | 0.3% | 0.8% | 1.3% | 1.5% | 3.9% | 4.8% | 6.5% |
| Consolidated Edison Co-NY Inc | 4.7% | 3.8% | 4.1% | 7.7% | 12.7% | 16.6% | 18.7% | 19.7% |
| New York State Elec & Gas Corp | 6.7% | 6.1% | 8.6% | 8.1% | 10.2% | 15.6% | 17.7% | 21.2% |
| Niagara Mohawk Power Corp | 6.1% | 6.8% | 7.5% | 8.1% | 10.8% | 10.7% | 15.4% | 17.5% |
| Orange & Rockland Utils Inc | 29.6% | 34.3% | 36.0% | 34.2% | 31.3% | 31.9% | 31.5% | 28.4% |
| Rochester Gas & Electric Corp | 14.7% | 13.5% | 19.9% | 23.1% | 21.3% | 21.8% | 22.9% | 25.2% |

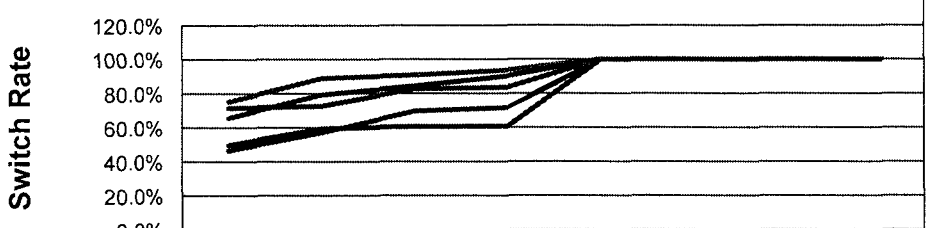
## Texas

The migration in Texas to industry restructuring and customer choice has taken place in a genuinely unique context. Unlike the other states in the continental United States, the State of Texas exercises authority over most of the wholesale market in the state because the market does not operate in interstate commerce and is therefore not regulated by the Federal Energy Regulatory Commission (FERC).[10] Rather, the Electric Reliability Council of Texas (ERCOT) manages the grid and is overseen by the Public Utilities Commission of Texas (PUCT). Unitary regulation has contributed to the ability of the Texas State Legislature and the PUCT to design and implement a restructuring game plan that coordinates competition in both wholesale and retail markets.

The Lone Star State was familiar with independent generation by the time of its 1999 restructuring law, having been the locus of numerous non-utility gas cogeneration facilities. Separating the generation and delivery functions in the electricity industry was something Texas felt confident in moving ahead with in the effort to seek competitive efficiencies.

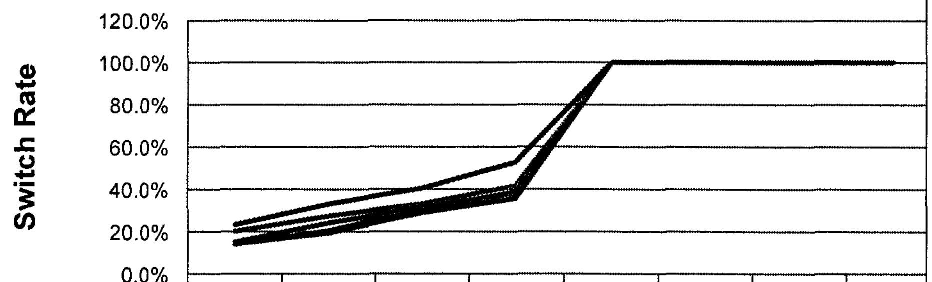
Texas has fully separated the supply and delivery functions. Since the end of the "Price-to-Beat" default service program, 100% of all C&I and residential demand in investor-owned utility delivery areas is being served competitively (Charts 7 & 8). While a substantial role is played by suppliers affiliated with distribution utilities, the market has attracted over 30 licensed residential suppliers and double that number in the C&I sector.

**Chart 7:**
**TX: Non-Residential Switch Rates: 2003-2010**




| | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2Q 2010 |
|---|---|---|---|---|---|---|---|---|
| Oncor | 46.4% | 57.0% | 69.5% | 71.7% | 100.0% | 100.0% | 100.0% | 100.0% |
| CenterPoint | 49.6% | 59.4% | 60.6% | 60.8% | 100.0% | 100.0% | 100.0% | 100.0% |
| AEP Central | 75.1% | 88.7% | 90.7% | 93.4% | 100.0% | 100.0% | 100.0% | 100.0% |
| AEP North | 65.6% | 79.3% | 84.4% | 90.1% | 100.0% | 100.0% | 100.0% | 100.0% |
| TNMP | 71.4% | 72.6% | 82.6% | 83.5% | 100.0% | 100.0% | 100.0% | 100.0% |

**Chart 8:**
**TX: Residential Switch Rates: 2003-2010**




| | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2Q 2010 |
|---|---|---|---|---|---|---|---|---|
| Oncor | 14.1% | 19.3% | 28.8% | 35.5% | 100.0% | 100.0% | 100.0% | 100.0% |
| CenterPoint | 14.0% | 20.4% | 30.4% | 38.8% | 100.0% | 100.0% | 100.0% | 100.0% |
| AEP Central | 20.2% | 27.3% | 33.0% | 41.7% | 100.0% | 100.0% | 100.0% | 100.0% |
| AEP North | 23.1% | 32.9% | 40.4% | 52.8% | 100.0% | 100.0% | 100.0% | 100.0% |
| TNMP | 15.1% | 24.0% | 31.3% | 38.2% | 100.0% | 100.0% | 100.0% | 100.0% |

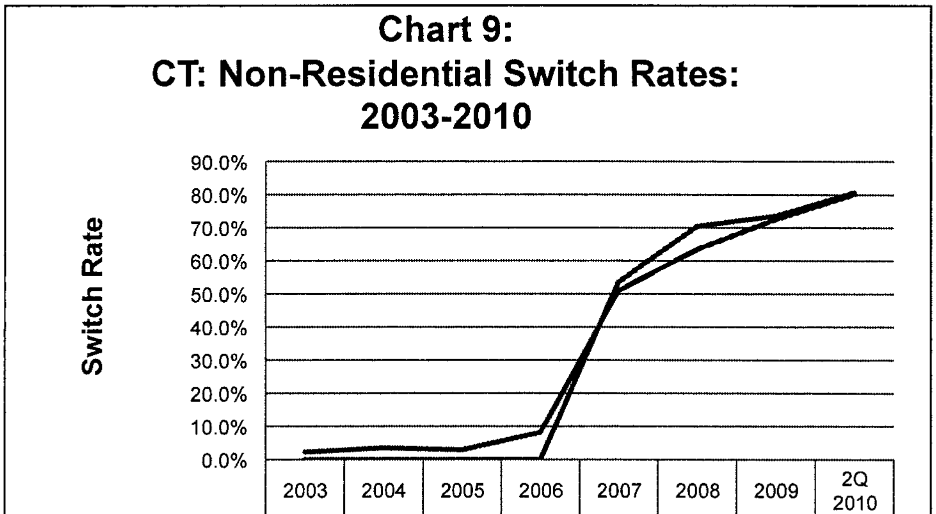
The PUCT has adopted an energy-only resource adequacy policy designed to encourage the introduction of 21st Century technologies such as renewables. Consistent with a customer-centric restructuring philosophy, the PUCT is working to ensure every customer in ERCOT competitive areas has a smart meter this decade. These meters are expected to spur a wide range of customer innovations along with dynamic price settlement on a 15-minute basis.

More than a solution to problems in traditional regulation, Texas has shown that customer choice and competitive industry restructuring involves the creation of opportunity for the future.

## Connecticut

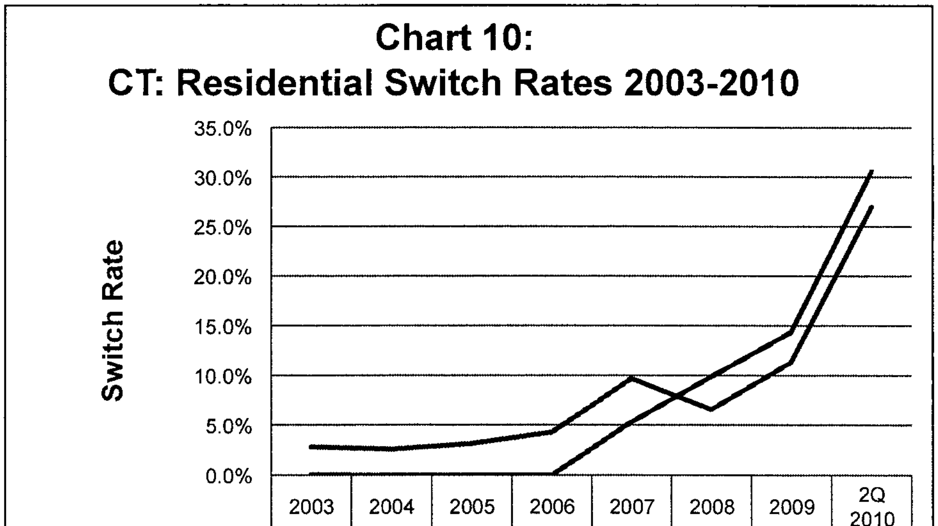
Connecticut's restructuring law provided all consumers the right to choose a supplier by July 2000. By the time that date arrived, Nutmeg State utilities had divested their generation assets. However, the Department of Public Utility Control (DPUC) recognized that generation divestment alone without other measures would not lead to the exercise of customer choice. As rate caps were about to expire at the end of 2006, the DPUC relied on existing authority to revise the rules of the game.

The DPUC instituted an auction-based procurement method for utility default service to customers who do not choose to purchase from a competitive provider. Since then, C&I choice has swung sharply upward. Over half of total electricity demand in the Nutmeg State's two investor-owned utility service areas has switched to one of the eight competitive suppliers operating in both utility areas. By mid-2010, the percentage of competitively served C&I demand in both utilities rose above 80% (Chart 9).




| | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2Q 2010 |
|---|---|---|---|---|---|---|---|---|
| CT Light & Power Co. | 2.2% | 3.5% | 2.9% | 8.1% | 51.0% | 63.6% | 72.5% | 80.2% |
| United Illuminating Co. | 0.0% | 0.0% | 0.0% | 0.0% | 53.6% | 70.5% | 73.6% | 80.7% |

The share of residential demand served competitively also has a steep trajectory, with almost one-third of residential electricity consumption served by competitive providers (Chart 10).




| | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2Q 2010 |
|---|---|---|---|---|---|---|---|---|
| CT Light & Power Co. | 2.8% | 2.6% | 3.1% | 4.3% | 9.7% | 6.6% | 11.3% | 27.0% |
| United Illuminating Co. | 0.0% | 0.0% | 0.0% | 0.0% | 5.3% | 9.9% | 14.3% | 30.6% |

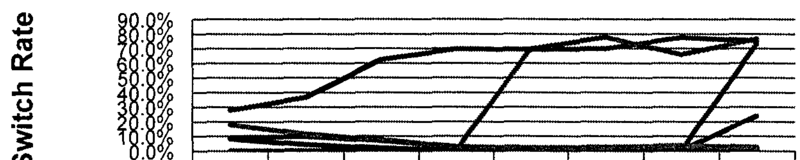
Connecticut can be seen as a microcosm of the generally successful rollout and performance of competitive choice in much of New England. A public opinion survey on a range of energy issues carried out for the New England Energy Alliance in April 2010 in the region's six states showed wide support favoring the opportunity to purchase electricity competitively. The results of the survey underscored the general theoretical support for market-based solutions to energy issues from climate change to energy pricing as well as practical acceptance of customer choice and competition in light of experience with electricity restructuring.[11]

## Pennsylvania

Until recently, customer choice in Pennsylvania has been a utility-by-utility phenomenon under legal settlements stemming from the state's general restructuring law. The Keystone State's 1996 legislation was one of the earliest in the nation and resulted in a large portion of utility-owned generation being divested. Competitive wholesale generators and distribution utilities became major participants in the successful development of PJM's competitive wholesale electricity market.

Pennsylvania illustrates the impact that differing rules for individual utilities can have within the same state even when there is a generally applicable restructuring law. C&I customers in two service areas among the state's seven investor-owned utilities, Duquesne Light and Penn Power, were able to move more quickly to take advantage of choice. Exercise of choice has expanded rapidly more recently with the end of transitional rate caps. C&I customers in the PPL service area have quickly moved nearly en masse from utility service to competitive suppliers, joining Duquesne and Penn Power in having about three-fourths of C&I electricity demand served competitively. C&I customers in UGI are beginning to exhibit a similar trend line (Chart 11).

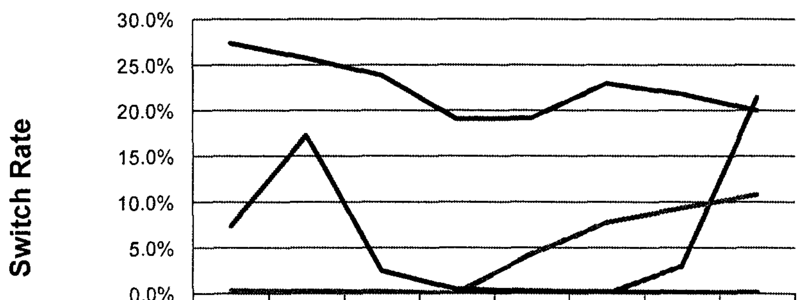
**Chart 11:**
**PA: Non-Residential Switch Rates: 2003-2010**




| | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2Q 2010 |
|---|---|---|---|---|---|---|---|---|
| Duquesne Light Co | 27.9% | 36.6% | 62.4% | 69.6% | 69.4% | 69.8% | 77.4% | 75.3% |
| PPL Electric Utilities Corp | 8.0% | 4.3% | 1.8% | 0.5% | 0.1% | 0.1% | 0.1% | 73.4% |
| Pennsylvania Power Co | 0.0% | 0.0% | 0.0% | 0.3% | 69.6% | 77.6% | 65.9% | 76.5% |
| PECO Energy Co | 9.1% | 9.8% | 7.0% | 2.7% | 2.2% | 1.8% | 1.5% | 1.4% |
| UGI Utilities, Inc | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.3% | 23.8% |
| West Penn Power Co | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 1.8% | 2.2% |
| Met-Ed/Penelec | 17.9% | 11.7% | 7.7% | 2.7% | 2.2% | 2.6% | 3.7% | 2.5% |

As has been customary, growth in residential choice has largely followed in the wake of surging C&I competitive supply. Duquesne has had fairly high residential participation (in the range of 19-27%) for a number of years. More recently, in tandem with their respective surges in C&I choice, Penn Power and PPL have seen an upswing in residential choice, with PPL rapidly coming to parity with Duquesne (Chart 12).

**Chart 12:**
**PA: Residential Switch Rates: 2003-2010**




| | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2Q 2010 |
|---|---|---|---|---|---|---|---|---|
| Duquesne Light Co | 27.4% | 25.7% | 23.8% | 19.1% | 19.2% | 23.0% | 21.8% | 20.0% |
| PPL Electric Utilities Corp | 0.1% | 0.1% | 0.1% | 0.0% | 0.0% | 0.0% | 3.0% | 21.4% |
| Pennsylvania Power Co | 0.3% | 0.3% | 0.2% | 0.0% | 4.3% | 7.7% | 9.3% | 10.8% |
| PECO Energy Co | 7.3% | 17.3% | 2.5% | 0.5% | 0.3% | 0.2% | 0.2% | 0.1% |

The Pennsylvania Public Utilities Commission has been steadily putting in place well-developed wholesale procurement programs for utility default service and retail market rules that address a broad range of conditions related to customer choice. Those policies and programs include enhanced data and information exchange between utilities and licensed competitive providers; a uniform eligible customer list; utility consolidated billing and purchase of receivables programs; uniform disclosure requirements for default service procurement results; a uniform price to compare; and various other measures.

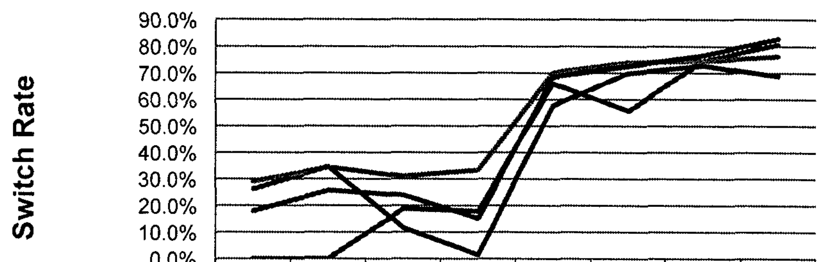
There are widespread expectations that both C&I and residential choice will develop rapidly as rate caps end at the end of 2010 for PECO, Penelec, Allegheny West and West Penn and level paying field conditions become the order of the day.

## Illinois

In late 2009, the Land of Lincoln marked a full decade of customer choice, by which time half of all electricity demand in the state was served by competitive suppliers. This growth in competition was accounted for entirely by the C&I sector. While there were some complex and contentious regulatory proceedings in the first several years of the transition period following the 1997 enactment of the restructuring law, the Illinois Commerce Commission (ICC) had delivery service rates and competitive rules in place for the commencement of choice in late 1999. Larger C&I customers were able to access the market for competitively provided power, even in the face of stranded cost charges.

From 2003 to mid-2006, the competitively served share of C&I demand varied somewhat by utility and year, but statewide was generally at about 30%. After mid-2006, C&I demand dramatically shifted toward choice with the end of stranded cost charges and the ICC declared additional C&I classes as "competitive." Utilities were obliged to provide only hourly priced service to C&I customers declared competitive. With more potential customers, new alternative suppliers entered the market to meet customer demand – two dozen in ComEd's northern Illinois area and a dozen in the downstate Ameren utilities. By mid-2010, three-fourths of all C&I demand was met under choice contracts, with only smaller business customers still taking utility bundled service (Chart 13).

**Chart 17:**
**IL: Non-Residential Switch Rates: 2003-2010**




| | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2Q 2010 |
|---|---|---|---|---|---|---|---|---|
| Central Illinois Light Co. | 0.0% | 0.0% | 18.8% | 18.0% | 66.0% | 55.6% | 74.4% | 80.7% |
| Central Illinois Pub Serv Co. | 26.1% | 34.6% | 11.6% | 1.5% | 57.8% | 69.8% | 72.8% | 68.8% |
| Commonwealth Edison Co. | 29.1% | 34.4% | 31.0% | 33.4% | 70.1% | 73.9% | 74.4% | 76.2% |
| Illinois Power Co. | 17.9% | 25.6% | 23.8% | 15.2% | 68.4% | 72.5% | 76.6% | 82.9% |

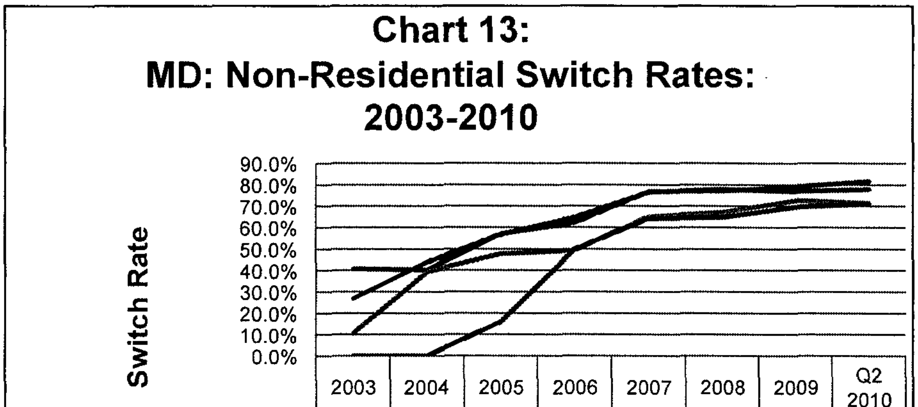
The success of the Illinois C&I market has set the stage for a surge in residential and small business customer choice. Over the past year and a half, utilities, customer groups and competitive suppliers have negotiated the details of purchase of receivables (POR) and utility consolidated billing (UCB) for residential and small business customers. Once implemented by the ICC in 2011 these rules are expected to fuel the exercise of choice by residential and small business customers.

## Maryland and the District of Columbia

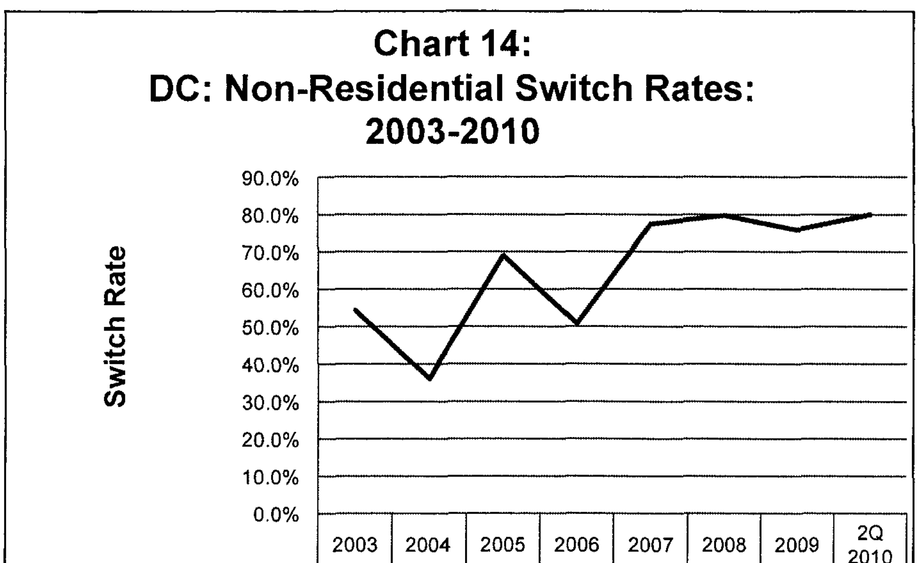
Maryland and Washington, DC, share a major utility, Potomac Electric Power Co. (Pepco), and both jurisdictions have adopted customer choice policies. They also share similar patterns in the vigorous exercise of choice by C&I customers. More recently, however, they have diverged in development of residential choice – something that may only be a temporary condition. Maryland and the District also offer the opportunity for many federal policy makers and regulators to directly observe electricity choice in action.

Maryland provides an interesting example of how an excess of caution in making the competitive transition can have unintended adverse consequences. In the case of Baltimore Gas & Electric (BGE) in 2006, as a pre-determined end of rate caps approached, wholesale electricity prices were being pushed higher by strong demand – particularly for natural gas, for which production in the Gulf of Mexico was sharply curtailed because of Hurricanes Katrina and Rita. The conjunction of a pre-set date for a procurement process and a spike in the market set the stage for a substantial rise in rates for utility default service to BGE's residential and small business customers. The problem was not customer choice or restructuring. A reluctance to promptly implement customer choice and to provide flexibility, especially when it came to smaller customers, resulted in rate shock and political repercussions.

The path of customer choice in the C&I sector has been roughly similar in all utilities serving Maryland and DC, with migration of 70-80% of all C&I demand to the market. Only smaller businesses have stayed with default supply from the traditional utility. In the District and its Maryland suburbs, federal government facilities have aggressively sought the savings available in the competitive market (Charts 14 & 15)



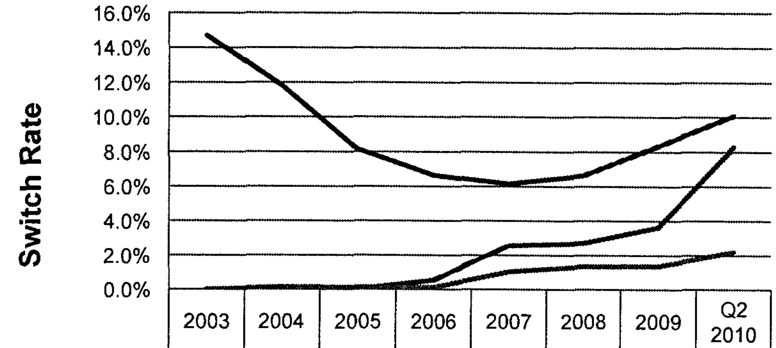

| | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | Q2 2010 |
|---|---|---|---|---|---|---|---|---|
| Potomac Electric Power Co | 40.7% | 40.1% | 57.1% | 62.1% | 76.8% | 77.0% | 79.1% | 81.6% |
| Baltimore Gas & Electric Co | 26.8% | 43.7% | 56.7% | 64.6% | 76.4% | 77.8% | 77.0% | 77.9% |
| Delmarva Power & Light Company | 10.5% | 39.3% | 47.6% | 49.4% | 65.0% | 67.0% | 72.6% | 71.4% |
| The Potomac Edison Co | 0.0% | 0.1% | 15.9% | 49.8% | 64.1% | 64.7% | 69.6% | 71.0% |




| | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2Q 2010 |
|---|---|---|---|---|---|---|---|---|
| Potomac Electric Power Co. | 54.3% | 36.1% | 69.0% | 50.6% | 77.4% | 79.7% | 75.8% | 80.0% |

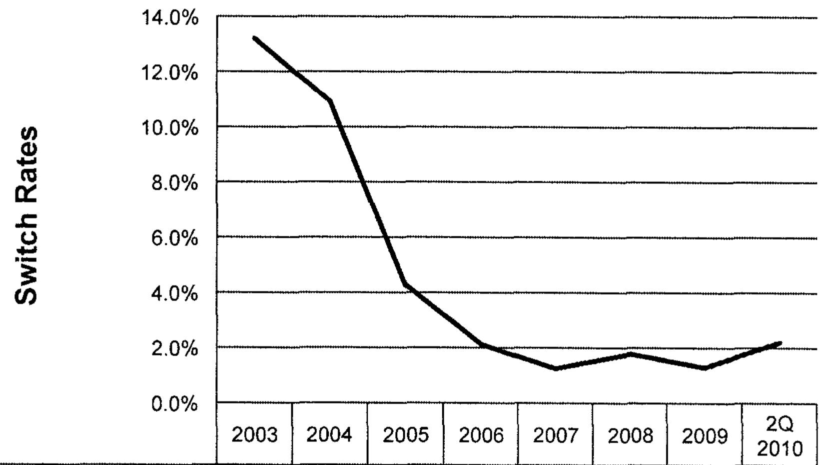
Maryland and District residential choice trend lines have differed markedly (Charts 16 & 17). In 2003, residential switching in the Pepco's District territory exceeded 13% but had fallen to about 2% by mid-2010. Things have gone the opposite direction in Maryland, not only in Pepco's territory but also in BGE's and Delmarva's. With the end of rate caps in 2006 in most of Maryland, residential choice rose by mid-2010 to over 10% of Pepco's demand. Similarly, in 2006 the share of residential demand served competitive suppliers in BGE was just under 1% but by mid-2010 that figure had risen to over 8%. Recent figures available from the Maryland Public Service Commission show the level of BGE's demand served competitively at nearly 13% and PEPCO's competitively supplied demand at over 12% in September 2010.[12]

**Chart 15:**
**MD: Residential Switch Rates: 2003-2010**




| | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | Q2 2010 |
|---|---|---|---|---|---|---|---|---|
| Potomac Electric Power Co | 14.7% | 11.8% | 8.1% | 6.6% | 6.2% | 6.6% | 8.3% | 10.1% |
| Baltimore Gas & Electric Co | 0.0% | 0.0% | 0.0% | 0.5% | 2.5% | 2.7% | 3.6% | 8.3% |
| Delmarva Power & Light Company | | | | | | | | |

**Chart 16:**
**DC: Residential Switch Rates: 2003-2010**




| | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2Q 2010 |
|---|---|---|---|---|---|---|---|---|
| Potomac Electric Power Co. | 13.2% | 10.9% | 4.3% | 2.1% | 1.2% | 1.8% | 1.3% | 2.2% |

The similarities and variations between Maryland and the District in competitive activity serve as a reminder that restructuring is not an identical process across jurisdictions. A great deal is being learned about how differing rules impact the process but that when given the opportunity under proper conditions, both C&I and residential customers avidly exercise choice.

## CUSTOMER CHOICE – LETTING IT WORK

### Experience has now demonstrated that

- Wholesale electricity markets can operate on a competitive basis;
- Market forces will produce efficiencies in the power industry;
- Multiple suppliers of electricity at retail can deliver savings and customized products to customers through bilateral contracts; and
- C&I and residential customers can and will choose among suppliers competing to satisfy their energy needs.

Experience has also clarified the conditions that contribute to effective competitive retail electricity markets.

### Two overarching conditions will be familiar since they are as important for the transition to choice as to the operation of a traditional regulated monopoly:

- ***Stable Regulation:*** A stable and predictable regulatory environment relies upon regulators and policymakers adhering to decisions and actions and otherwise keeping faith with the philosophy underpinning regulatory reform. In the case of customer choice systems, it is important that there is a commitment to market-based reforms and restraint in tinkering with the rules of the game in response to the up-and-down vagaries of the market.
- ***Clear Rules:*** The rules need to be clear and applied fairly. A competitive system based on customer choice in the market place will not function well if the rules are vague or if regulators or policy makers favor some competitors or customers over others.

### Three conditions are largely determined at the federal level:

- ***Wholesale Competition:*** Competitive wholesale markets are necessary for retail choice. Utilities, retail suppliers, wholesale generators and market intermediaries need to freely negotiate prices and contract terms, with adequate safeguards in instances of unavoidable market power such as reliability must-run generation units.
- ***Transmission Access:*** Bulk transmission grids that provide for non-discriminatory access and pricing provide the certainty needed for market-based wholesale transactions to carry through to delivery.
- ***RTOs:*** Regional Transmission Organizations are proving important in assuring fair transmission access and for the efficient pricing and procurement of ancillary services, real time supplies and the operation of various market mechanisms, such as bidding demand curtailment into the wholesale power market. States play a role by deciding whether to encourage or require their utilities to join RTOs or by allowing customers to participate in RTO markets.

### Five other conditions reside at the state level:

- ***Cost-Based Delivery Rates:*** : Delivery service rates and the terms and conditions for electricity delivery should be competitively neutral and neither favor nor disadvantage some customers or suppliers over others. Delivery rates should be cost-based and must not include generation-related costs, either for power assets retained by utilities or as a means of creating customer cross-subsidies within competitive procurement processes.
- ***Market-Based Default Service:*** To the extent the conventional distribution utility continues to provide tariffed supply as the "provider of last resort" (POLR), pricing should be determined in competitive procurement programs.
- ***Customer Data & EDI:*** Customers should have fair access to their own usage data and should have the right to provide access for alternative suppliers in a usable form for marketing, product design, pricing and billing. Electronic Data Interchange standards and processes are necessary for proper data sharing.

- ***UCB & POR:*** Effective implementation of choice for residential and small business customers should include minimizing transaction costs through such mechanisms as reasonable arrangements for utility consolidated billing (UCB) that combines delivery and competitive supply charges and for purchase of receivables (POR) of competitive suppliers by utilities. These provisions may prove to be temporary arrangements as smart grid and other Internet-based developments facilitate data sharing among utilities, customers and suppliers.

- ***Customer Education & the Promotion of Choice:*** With the Internet, information can be made available to customers more easily and usably than ever before. Regulators and utilities have a special role to play in providing access to information, including links to suppliers, and clearly explaining the market rules to consumers accustomed to monopoly service.

## RE-SET THE CHOICE DEBATE

***The retail choice debate needs a re-set. But from what to what?***

The retail choice debate we have been familiar with has had three central points of contention.

First has been price comparison. Dueling studies purport to show either that competitive prices are higher or lower than in regulated monopoly regimes. There are also the studies that compare current competitive rates with hypothetical regulated rates that might have prevailed absent restructuring. While interesting, price comparison is ultimately unsatisfying and indeterminate. The partisans in the debate will disagree on study time frames and the samples used, suspecting the other of choosing favorable ground to argue from. The record of customers exercising choice would indicate that customers themselves see cost savings opportunities and other benefits in choice.

Second, there has been a focus on imperfection in customer choice systems, including the possibility of market power in the hands of some market participants, with the proposed cure a return to conventional regulation and the recreation of vertically integrated local monopolies. This criticism ignores the comprehensive regulatory oversight framework that characterizes both the competitive wholesale market and the retail market. Indeed, there is a strong argument to be made that resources formerly devoted to ritualistic processing of the minutiae of pricing generation and designing commodity rates can be put to better use. FERC, state utility regulators and compliance teams of regional transmission organizations consistently exhibit high degrees of professionalism and awareness in the regulation of restructured wholesale and retail markets.[13]

Third, some opponents of customer choice have argued that too many customers are not in a position to make decisions that will benefit them, that information is insufficient, or that a competitive market may limit the ability of regulators and policy makers to achieve social or environmental goals. These contentions appear contrary to experience so far. Customer choice has not proven an obstacle to assisting low-income customers or to developing state-based renewable portfolio standards. If anything, the jurisdictions in the northeastern quadrant of the country where choice is very extensive appear to have taken more initiative in these areas than states that remained with traditional regulation. And in the main, customer choice jurisdictions have strong records of operating low-income energy assistance programs and have shown no inclination to back away from them.

Experience has rendered the old debate obsolete. The electricity industry is now characterized by competitive wholesale markets and transmission access, a major role for non-utility generation and retail customer choice as a *fait accompli* for vast areas of the country. The debate should now concentrate on anticipating the future rather than on turning back the clock. The central question for the future is whether the traditional monopoly regulatory model can perform as well in achieving important goals as will customer choice and retail competition.

## The Smart Grid

Transforming the electricity grid from its electro-mechanical past to a digital, solid-state future will take years and a significant infusion of dollars. Whether the smart grid investment results in merely incremental improvement or revolutionary change will depend less on its capabilities than on how an intelligent network is used. Will the smart grid be a tool mainly for better command and control by delivery system operators, or will it also help buyers and sellers interface with one another to tailor service, convey price signals and invent efficiencies? One of the key considerations for utilities and regulators in proceeding with billions of dollars in smart grid investment will be the value of using a digital, information-based network to expand choices for customers rather than to reinforce traditional monopoly protections. The smart grid is fast being understood as key to integrating innovative applications such as electric vehicles and smart appliances into the network.

Smart Grid means that the underlying diversity among consumers can be addressed. Retailers, in order to develop and maintain profitable niches, will try to meet the varying preferences of consumers. This development goes beyond traditional demand response, for example. Various forms of active energy management will be tried and improved as time goes on. While market outcomes cannot be predicted with precision, we can anticipate that customers and service providers will innovate to the point that energy savings and efficiency in utilization will exceed anything that could be either imagined or effectuated by regulators and lawmakers whose template is the old utility model with consumers in a far more passive status.

## Clean Energy

The interest in lower carbon intensity in energy production and use has evolved in parallel with the implementation of customer choice. The two movements share some common roots. The introduction of non-utility generation by the Public Utility Regulatory Policies Act of 1978 (PURPA) was motivated in part by the belief that regulated monopolies were insufficiently motivated to develop more efficient power plants, especially smaller units. The sense that there were electricity efficiencies to be found outside the traditional vertically integrated monopoly protected model was equally the animating spirit among early advocates of industry restructuring and customer choice. Nonetheless, an opinion about customer choice does not dictate an opinion one way or the other about wind, solar, carbon emissions, emissions cap-and-trade programs, clean coal, next-generation nuclear, plug-in hybrid electric vehicles or net metering. The question is whether customer choice and a commitment to competition and the power of price signals will make for better decision making and more efficiency in considering the full range of clean energy options.

## Demand Response

No matter the opinions about clean energy sources and the value of reducing carbon emissions, there is recognition of the obvious – each incremental kilowatt-hour produced during peak demand costs more than a kilowatt-hour at low demand. In customer choice systems, these widely differing costs can be reflected in dynamic prices and customers can choose to shift energy use from high-demand, high-priced periods to low-demand, low-priced periods. In traditional retail regulated systems, even when there is wholesale competition, prices are routinely averaged for customers whether they like it or not, concealing the true price signals reflecting time-based and seasonal costs of production and use.

## Satisfying Customers

It is impossible to look at the larger economy and deny that the driving force in every industry sector is the contest to satisfy increasingly discerning buyers of services and products. Consumers increasingly insist on tailoring products to meet their own tastes, doing so through ubiquitous communications modalities. Characteristic of the digital information revolution now finding its way into the electricity industry by way of the smart grid is the impatience of consumers with intermediaries who usurp the role of the individual in making choices. By its very nature, traditional regulation inhibits the give-and-take between buyers and sellers. Rather than being a welcome protector by simplifying and averaging, a system that seeks to control prices and service offerings comes into conflict with customers who regard themselves as discerning and capable.

The one thing that can be said about customer satisfaction is that the bar is ever rising. Customer choice, whether in electricity or any other sector, has embedded in its reason for being the expectation that the bar should rise as fast as innovation can drive it. Traditional regulation proceeds from the principle that the primary arbiters of what will and should satisfy are experts operating through an administrative process. This is where the debate is at its sharpest.

## LOOKING AHEAD

A decade of customer choice has played out well in the century since Thomas Edison, George Westinghouse and Nicola Tesla vigorously promoted their competing visions for an electric future. A massive, capital-intensive and technology-driven industry emerged that enriched billions of lives around the world.

The sense of electricity as magic gave way to its being taken for granted, mundane in its sameness but with a marvelous versatility that makes it the energy source that drives modernity and the good life. It is easy to forget that the electricity industry has undergone transformational change throughout its history. The railroad regulatory model was imposed years into the replacement of gas lighting with electricity. Federal involvement came with the New Deal in the 1930s. Bulk transmission and nuclear power wrought their own transformations of the industry, as did the deregulation of wellhead gas prices and the opening of access to interstate pipelines. In 1978 PURPA paved the way for a competitive merchant generation sector. The industry has never been static. Competition and customer choice are one more important step.

As the debate continues, the issues addressed here will be revisited. More data will come in. Residential choice will increase. C&I customers will adjust their purchases as the economy recovers. Customer choice will continue to challenge regulatory prescription. It is vitally important that state and federal policy makers allow this next step in the electricity industry's evolution to continue, and not entertain proposals to roll back competitive reforms, else they jeopardize important economic and environmental benefits for consumers from the innovation that Smart Grid and other technological advances will provide.

## Endnotes

[1]This quotation is popularly attributed to the German philosopher Arthur Schopenhauer (1788-1860)

[2]The electricity restructuring debate was initiated in the mid-1980s by a number of state utility regulators informed by their experiences in the implementation of customer choice and price decontrol in telecommunications, natural gas, railroads and trucking. The Illinois Commerce Commission issued a series of papers in 1984 and 1985 suggesting that a movement to competitive generation and customer choice of supplier could address dysfunction in state electric utility regulation.

[3]California limited utilities to buying power supplies in the day-ahead, centrally operated spot market, denying them the ability to hedge volatile spot-market prices by purchasing under long-term fixed-price contracts. Other competitive jurisdictions avoided this anti-market construct by permitting buyers and sellers substantially more flexibility in contracting. See the FERC staff report http://www.ferc.gov/industries/electric/indus-act/wec.asp.

[4]For purposes of this paper, 17 states and the District of Columbia are regarded as having active markets (CA,CT,DC,DE,IL,MA,ME,MI,MT,NH,NJ,NY,OH,OR,PA,RI,TX). California, where substantial demand is still served by competitive providers, is considering easing its near decade-long suspension of new enrollments; Michigan currently limits competition to 10% of electricity demand for each of the state's investor-owned utilities; and Oregon and Montana have significant obstacles to the exercise of choice. Yet all four states still show appreciable portions of demand being served competitively. The U.S. Energy Information Administration maintains a website that is periodically updated to reflect new developments in electricity restructuring. http://www.eia.doe.gov/cneaf/electricity/page/restructuring/restructure_elect.html. EIA reports 2008 total electricity sales in the lower 48 states at 3.72 billion MWh with 1.56 billion MWh sold in the seventeen choice jurisdictions (1.56/3.72 = 41.9%) http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html

[5]For a review of the origins, comparative performance of North American and European electricity restructuring see "The Grand Experiment," by Terrence L. Barnich and Philip R. O'Connor, Public Utilities Fortnightly, February 2007.

[7]The charts in this paper rely on data reported in the quarterly "KEMA Retail Energy Outlook." KEMA, a Netherlands-based consulting firm with its U.S. operations headquartered in Burlington, MA, is widely regarded as an authoritative provider of information about trends in competitive retail electricity markets. KEMA utilizes EIA and state utility commission data bases and its own estimating methodologies to develop final estimated figures.

[8]A small number of accounts and MWh were competitively served in Nevada and Virginia in most years.

[9]KEMA and the Energy Retailer Research Consortium (ERRC) both produce periodic reports on competitive supplier populations, market shares, acquisitions and mergers, market entry and exit and estimated operating cost structures and operating margins. KEMA publishes Retailer Landscape every six months and the monthly Retail Market Monitor. ERRC publishes the Annual Baseline Assessment of Choice in Canada and the United States (ABACCUS).

[10]Most of Texas is served by a grid operating within state boundaries and without exchanges with systems in other states. ERCOT carries out its work under the auspices of the State of Texas. Outside of Texas, FERC has fostered wholesale power competition but does not directly correlate its actions at wholesale with state-regulated retail power markets. Therefore, the issues of FERC jurisdiction in wholesale markets versus state authority in retail matters have not arisen in Texas.

[11]The full NEEA survey conducted by Opinion Dynamics Corporation can be found at http://www.newenglandenergyalliance.org/downloads/neea_charts_2010_energy_survey_results%20(1).pdf

[12]MPSC Monthly Choice Enrollment Reports can be found at http://webapp.psc.state.md.us/Intranet/CaseNum/submit_new.cfm?DirPath=\\Coldfusion\Electric Choice Reports\\2010 Electric Choice Enrollment Reports&CaseN=Electric Choice Enrollment Monthly Reports

[13]In September 2010, the COMPETE Coalition published a comprehensive review of the regulatory framework in which the electricity industry, both traditional monopoly and competitively restructured, operates: Regulation and Oversight of the Electric Power Industry http://www.competecoalition.com/files/Regulation%20and%20Oversight%20of%20the%20Electric%20Power%20Industry.pdf

### Note on Author

Philip R. O'Connor is a former utility regulator who served as Chairman of the Illinois Commerce Commission (1983-1985). He was an early advocate of competitive solutions in telecommunications, natural gas, electricity and power plant emissions reductions. O'Connor has been appointed by five consecutive Illinois Governors to numerous positions in Illinois State Government including Director of Insurance and member of the State Board of Elections. He earned his doctorate in political science from Northwestern University and in 2007-2008 served in the U.S. Embassy in Baghdad as an advisor to the Iraqi Ministry of Electricity.

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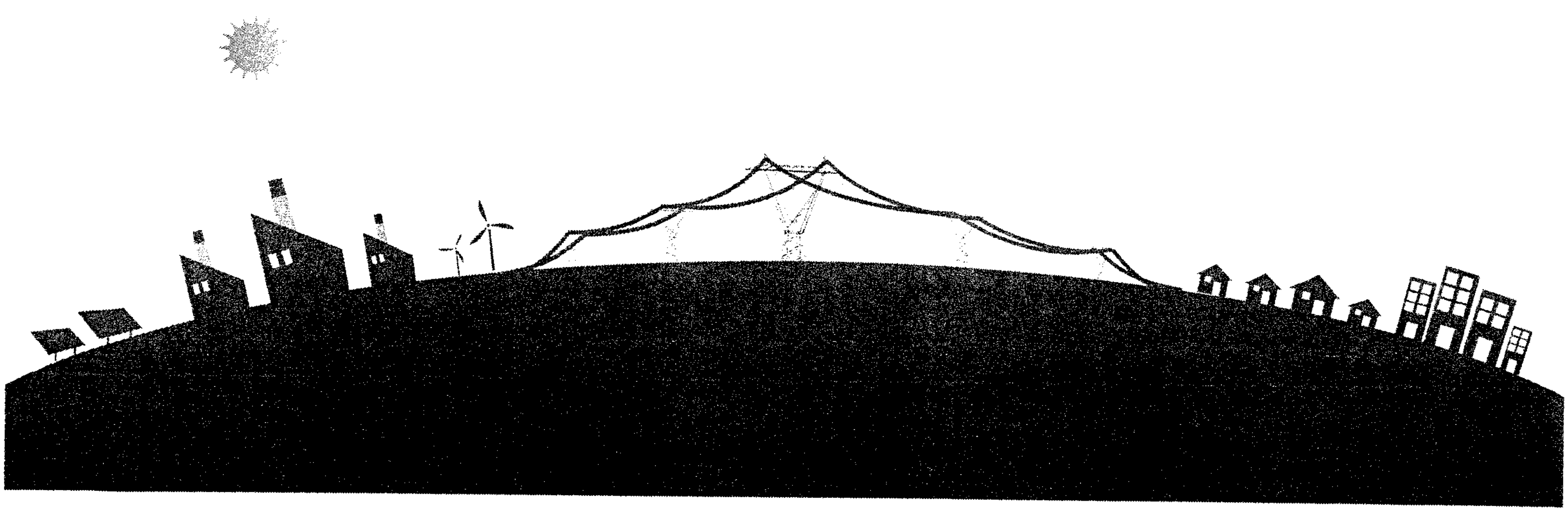


A17

nationalgrid

Thomas R. Teehan
Senior Counsel

January 22, 2010

**VIA HAND DELIVERY & ELECTRONIC MAIL**

Luly E. Massaro, Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02889

**RE: Docket 4041: Standard Offer Scrvice Procurement Plan Compliancc Filing**

Dear Ms. Massaro:

On behalf of National Grid,[1] I am filing ten copies of the Company's report regarding its review and analysis of procurement methods for Rhode Island. This filing consists of the report as well as supporting analysis as attachments. This filing is made in compliance with the Commission's direction in Commission Order 19839 that the Company file a report regarding the Company's review of procurement options and discussing the relative merits of a managed portfolio approach and an FRS approach including a comparison of gas and electric procurement activities and also including an analysis of administrative cost considerations. The Company intends to incorporate the results of this supply procurement analysis as it attempts to balance the relative strengths and weaknesses of the various procurement methods in fashioning a recommended approach for Commission consideration in the Company's upcoming Standard Offer Service filing on March 1, 2010.

Thank you for your attention to this transmittal. If you have any questions, please feel free to contact me at (401) 784-7667.

Very truly yours,

Thomas R. Teehan

Enclosure

cc: Docket 4041 Service List
Leo Wold, Esq.
Steve Scialabba, Division

[1] National Grid d/b/a Narragansett Electric Company ("National Grid" or "Company")

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS

RHODE ISLAND PUBLIC UTILITIES COMMISSION

| | | |
|---|---|---|
| National Grid<br>Standard Offer Service<br>Procurement Plan | ) | Docket No. 4041 |

## NATIONAL GRID'S REPORT REGARDING ITS COMPREHENSIVE REVIEW OF STANDARD OFFER SERVICE PROCUREMENT STRATEGIES

National Grid [1] submits this report in compliance with Commission Order #19839 regarding its comprehensive review of Standard Offer Service procurement strategies.

## Introduction

During the course of this docket, the Rhode Island Public Utilities Commission ("Commission") has prompted, and the parties have begun to engage in, a discussion regarding the advisability of a transition to a fully managed portfolio approach ("MPA") to procure energy supply for mass market customers (residential and small commercial). The Company indicated that it would conduct a review and analysis of its procurement methods in Rhode Island, taking into account its experience with different procurement methods in its affiliates' service territories, to determine the best procurement approach for its customers. As part of its analysis, the Company also considered the balance between the key goals associated with Standard Offer Service, including rate stability and

[1] The Narragansett Electric Company d/b/a National Grid hereinafter referred to as "National Grid" or "Company."

low rate level. This report summarizes the analysis of various procurement approaches and is responsive to the following inquiries, as ordered by the Commission:

(1) an assessment of the comprehensive review;

(2) empirical proof of savings of the managed portfolio approach or the full requirements service ("FRS") approach;

(3) the merits or lack thereof of a managed portfolio approach;

(4) an in-depth, detailed comparison of procurement of natural gas and electricity, reviewing symmetries and differences that might drive different policy approaches for each commodity; and

(5) an administrative cost analysis.

## 1. Assessment of the comprehensive review

The Company has completed an extensive study of procurement approaches, from which the strengths and weaknesses of the different approaches can be evaluated and insights can be developed. The Company engaged The NorthBridge Group ("NorthBridge"), a consulting firm with extensive expertise regarding electricity market pricing and standard offer service procurement, in order to assist with the comprehensive review of procurement approaches for Standard Offer Service for mass market customers. Specifically, NorthBridge analyzed the costs and risks associated with various procurement approaches. NorthBridge's quantitative analysis utilized a Monte Carlo simulation approach to replicate market uncertainty based on actual market data, including the prices for many different standard offer service products recently solicited by different utilities. Exhibit A is a presentation of the NorthBridge analysis as it relates to Rhode Island. Each procurement approach was evaluated using various metrics that pertain to objectives with respect to Standard Offer Service, including expected rate level, supply cost surprise, and rate volatility. Numerous portfolio approaches were reviewed, but three representative approaches were identified in order to illustrate conclusions drawn from NorthBridge's analysis:

(a) "Spot" Procurement: 100% spot market purchases;

(b) "Full Requirements" Product Procurement: 100% full requirements contracts (one-year contracts, half procured every six months); and

(c) "Block and Spot" Managed Portfolio: Targeted procurement quantities consisting of 25% spot market purchases, and 75% fixed-price predetermined-quantity (i.e., "block") contracts (equally split into 6-month, 2-year and 4-year contracts).

## 2. Empirical proof of savings of the MPA or FRS approach

As discussed above, the NorthBridge analysis is based on actual market data, rather than conjecture about the relative merits of various procurement approaches; therefore, it represents empirical evidence of the relative benefits of different procurement approaches. Furthermore, the analysis involves a comparison of standard offer service approaches against several metrics that pertain to various objectives with respect to Standard Offer Service, and therefore allows for an assessment of the tradeoffs with respect to key objectives, such as rate stability and low rate level.

The NorthBridge analysis indicates that the expected standard offer service rate under the Spot Procurement approach would be about \$2-3/MWh lower than the expected rate under different procurement approaches, but that the Spot Procurement approach would expose mass market customers to high levels of unexpected changes in supply costs, on the order of \$26/MWh on average in the top 10% of market scenarios. By comparison, the "Block and Spot" Managed Portfolio approach involves an expected standard offer service rate that is about \$2/MWh higher than under the Spot Procurement approach, but the level of supply cost uncertainty is cut significantly, to about \$10/MWh on average in the top 10% of market scenarios. Finally, the Full Requirements Product approach involves an expected standard offer service rate that is about \$1/MWh higher than under the "Block and Spot" Managed Portfolio approach, but the level of supply cost uncertainty is about \$3/MWh on average in the top 10% of market scenarios, which is much lower than the supply cost uncertainty value associated with the "Block and Spot" Managed Portfolio approach.

### 3. Discussion of the merits or weaknesses of a managed portfolio approach

The managed portfolio approach has advantages with regards to the inclusion of spot market purchasing. The Company believes that the utility should stay engaged in the power markets in order to provide the least cost supply that maintains rates within a reasonable degree of volatility. This level of engagement in the energy markets can be achieved by the Company's conducting some level of spot purchases through the ISO-NE, as it is doing currently since January 1, 2010. This direct involvement in the power markets also allows the Company to retain the ability to purchase replacement power in the event of a supplier default.

As indicated above, however, an approach that is entirely reliant upon purchases from the spot market involves a level of supply cost uncertainty (on a \$/MWh basis) that is arguably too large for mass market Standard Offer service customers. The "Block and Spot" managed portfolio involves much less supply cost uncertainty, because the purchased structured products help to reduce the risks associated with spot market purchases, but this comes at a higher expected rate. On the other hand, a procurement approach based solely on full requirements products significantly reduces the supply cost uncertainty as compared to the "Block and Spot" approach. This reduction in supply cost uncertainty results because full requirements suppliers are responsible for assuming, managing, and covering costs and risks (such as those associated with customer migration, transmission congestion, usage patterns, changes in laws and regulations, etc.), rather than leaving these risks to be managed by the Company on behalf of customers and exposing customers to the uncertain supply costs incurred by the Company. Although the full requirements product approach involves a higher expected rate, the analysis shows that the difference in the expected rate under the full requirements product approach versus under the "Block and Spot" approach is small (i.e., about \$1/MWh). In summary, the higher costs for full requirements products was found to be relatively small compared to the lower supply cost uncertainty and therefore added value for mass market customers.

## 4. Comparison of procurement of natural gas and electricity

The following section reviews the symmetries and differences that might drive different policy approaches for natural gas and electricity commodity. The differences in the gas and electric procurement activities performed by the Company are attributable to the differences in their respective wholesale markets. There are two key differences that affect the Company's procurement practices for these two commodities. First, the ability to store gas commodity is a key difference from electric commodity and changes the procurement approach. Second, electric wholesale markets are administered by regional Independent System Operators ("ISOs") that ensure the day-to-day reliable operation of the region's bulk power generation and transmission system, by overseeing and ensuring the fair administration of the region's wholesale electricity markets, and by managing comprehensive, regional planning processes. Due to the existence of the ISO, the Company's role is to engage in electricity purchases that balance competing concerns, such as rate stability and low rate level. By comparison, in the natural gas market, there is no analog to the ISO, so the Company's role also directly involves ensuring sufficient gas transmission capacity, storage, and peak supplies.

### A. Description of the Rhode Island Gas Portfolio

The fundamental goal of the Company's gas supply planning process is to ensure that there are adequate gas supplies to reliably meet the needs of customers under design winter conditions. In order to meet the load requirements under such conditions, the Company maintains a resource portfolio consisting of supply contracts, pipeline transportation, underground storage and peaking resources. In addition to pipeline capacity, the Company relies on underground storage capacity to meet fluctuations in customer requirements throughout the winter season. Similarly, peaking resources are used to meet winter requirements not met by pipeline and underground storage resources. Peaking resources are composed of both third-party delivered supplies as well as the Company's on-system liquefied natural gas ("LNG") facilities. In addition to serving as a supply source, the on-system LNG facilities are a critical resource used to meet hourly load fluctuations and to balance pressures across portions of the distribution system during periods of high demand.

In addition, the Company manages the gas supply cost to Rhode Island customers through a hedging program. The Company is required to hedge 60% of forecasted normal weather gas purchases for April and October and 70% of the forecasted purchases the remaining ten months. These are mandatory hedge volumes which are a regulatory requirement of the Gas Procurement Incentive Plan. In addition to the mandatory purchases the Company is required to hedge incremental discretionary volumes.

The management of the gas supply portfolio provides opportunities to optimize the value of the assets when they are not being fully utilized to meet customers' peak demand. The value derived from these optimization efforts is shared between the customers and the Company.

### B. Comparison of Gas to the Electric Portfolio

Unlike the gas business, long-term electric supply adequacy is the responsibility of the regional ISO and not that of the individual utility. The ISOs address this requirement by ensuring that there is adequate generation capacity and interconnecting markets that can meet the potential demand. It is the responsibility of the New England ISO ("ISO-NE") to determine the installed capacity requirements for the New England region, which includes Rhode Island. The ISO-NE is also responsible for the administration of comprehensive regional system planning processes to identify reliability needs, consider and evaluate potential solutions, and establish market rules for ensuring resource adequacy. National Grid, on behalf of its affiliates, is active in these planning processes. In contrast, as noted, the natural gas market involves no regional ISO or Regional Transmission Organizations, and thus reliability is the primary concern of the individual utility, which must acquire all resources in order to meet customer requirements.

In summary, there are two primary goals for the gas supply portfolio. First, on the delivery side, the goal is to reliably meet the design load requirements in a least-cost manner with a portfolio of resources including transmission capacity, storage assets and peaking supplies. The second goal is to reduce monthly volatility while providing the customer with low monthly gas supply costs. On the electric side, the Company has the primary goal of providing Standard Offer Service mass market customers with a supply portfolio that balances the level and volatility of rates, striving to keep both as low as can be reasonably achieved, consistent with the directive of least-cost procurement.

## 5. Administrative Cost Analysis

It is National Grid's experience that certain characteristics of a supply portfolio will drive the overall administrative costs, such as solicitation frequency and the regulatory approval process. On the other hand, portfolio size and contract types are minor drivers of administrative costs (i.e., there is no difference in administrative costs to conduct solicitations for full requirements versus block contracts). More resources may be required for specific aspects of the supply portfolio, such as:

- Increased quantity of contracts (i.e., how many contracts are layered in each month);
- Increased variation in the type of contracts (i.e., all one type or a mixture of products);
- Performing load bidding into the ISO for any portion of specific customer groups;
- The frequency of the solicitations, as well as conducting the solicitation separately from other National Grid distribution company solicitations; and
- The frequency of regulatory approvals (i.e., are individual contracts approved or are the final retail rates approved).

These characteristics not only increase the efforts required by the Electric Supply staff to procure Standard Offer Service, but will also increase the labor costs associated with the support necessary from accounting and risk management staff. In addition, increased uncertainty in cost recovery and prudency reviews would require more legal and regulation-related staff activity, as well as increased senior management involvement.

The range in administrative costs could vary significantly depending on the procurement approach. Table A, Estimation of Standard Offer Service Administrative Costs, shows the estimated annual costs of labor and supervision associated with administering various supply portfolios. The administrative costs for procuring Standard Offer Service under a FRS approach, based on semi-annual solicitations for FRS contracts, are estimated to be $340,000, or $0.055/MWh on a unitized basis (using the estimated 2010 deliveries related to Standard Offer Service of 6,200 GWh). Table A also shows a preliminary estimate for the administrative cost associated with a Block and Spot managed portfolio approach for mass market customers. This managed portfolio would include spot purchases (ISO-NE load bidding) and quarterly solicitations for block contracts, in addition to monitoring and reporting. The estimated costs of $450,000, or $0.072/MWh on a unitized basis, also include an increased level of activity required from support staff.

## Table A

### Estimation of Standard Offer Service Administrative Costs

| Different procurement approaches | Annual administrative cost estimate | Unitized cost per MWh |
|---|---|---|
| FRS approach | $340,000 | $0.055 |
| "Block and Spot" MPA approach | $450,000 | $0.072 |

## Conclusion

The Company, with the assistance of an experienced electric-market consulting firm, has completed an analysis of the various procurement methods available for obtaining electric supply for the Rhode Island mass market customers. This analysis has addressed the dual procurement goals of commodity cost and cost volatility. The Company also considered procurement methods that would best allow for continued or increased Company engagement in the energy markets.

As a general statement, the spot market approach produced the lowest expected supply rate while the FRS approach best controlled price volatility. However, the increase in expected supply rates for FRS products was relatively small as compared to the MPA or even to the spot approach, particularly when considering the much lower supply cost uncertainty. The Company also determined that spot market purchasing is effective in continuing to keep the Company engaged in the energy markets. The Company intends to incorporate the results of this supply procurement analysis as it attempts to balance the relative strengths and weaknesses of these procurement methods in fashioning a recommended approach for Commission consideration in the Company's upcoming Standard Offer Service filing on March 1, 2010.

# Exhibit A

**Analysis of Standard Offer Service Approaches for Mass Market Customers**

**by The Northbridge Group**

# Analysis of Standard Offer Service Approaches for Mass Market Customers

Prepared for National Grid

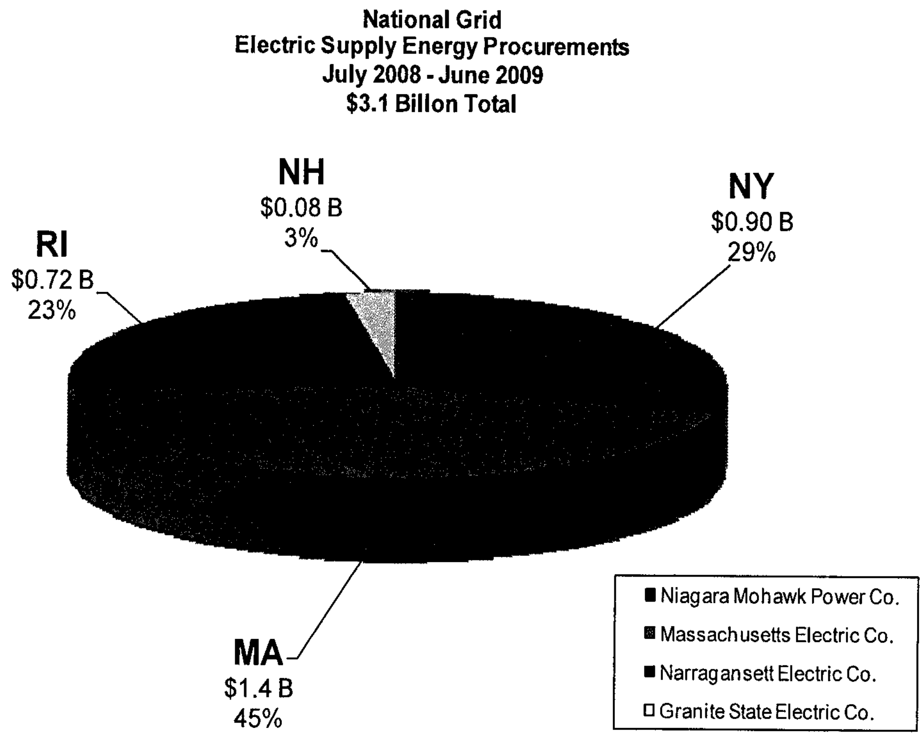
Re: RI PUC Order #19839

January 2010

NORTHBRIDGE

*This report presents an analysis of the relative costs and risks of different approaches to serve mass market standard offer service customers, and how different approaches could impact customers' standard offer service supply rates. While this report depicts potential future supply costs and rate levels, it is not intended to provide a prediction of absolute levels in the future associated with any particular approach for standard offer service supply procurement and ratemaking. As market prices and conditions change over time, expected absolute supply costs and rate levels would also change.*

Electric standard offer service (SOS) supply procurement decisions impact many customers and involve substantial amounts of money:




- Currently spending about $3.1 billion annually for 38,000 GWh
- The need for SOS is likely to continue for the foreseeable future

Our forward-looking quantitative analysis of SOS procurement approaches reflects mass market customer load in Rhode Island.

## Full Requirements Products

Most electric utilities in restructured states primarily use full requirements products to secure SOS supply for residential customers:

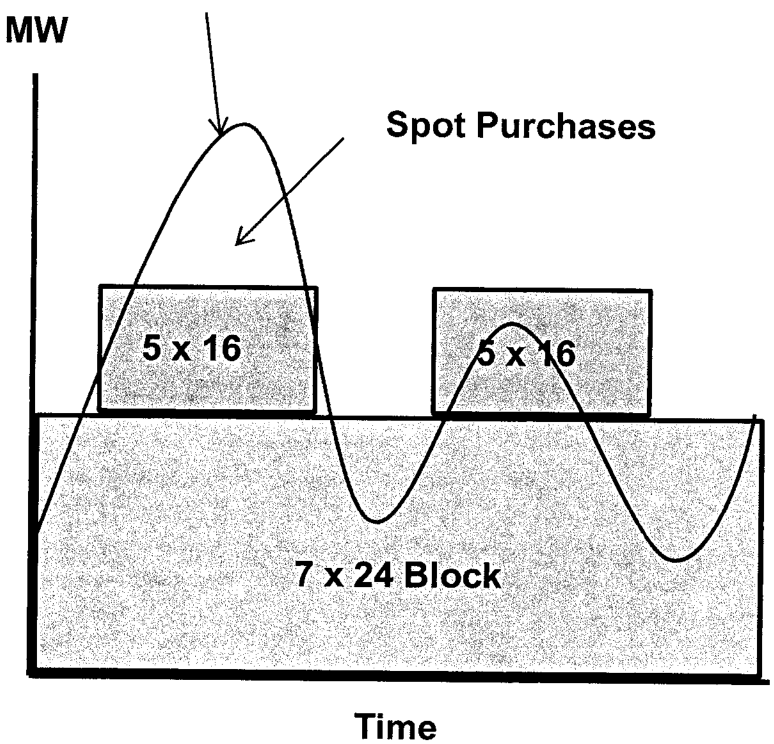
| State | Utility |
|---|---|
| CT | CLP, UI |
| DC | PEPCO |
| ME | BHE, CMP |
| MD | AP, BGE, DPL, PEPCO |
| MA | NG, NSTAR, WMECO |
| NJ | ACE, JCPL, PSEG, RECO |
| PA | FE, PPL, PECO, WPP |

### Key Features

- RFP/auction process
- Bundles energy, capacity, ancillary services, and often RECs
- Third party supplier assumes volume, price, and regulatory risks during the contract period
- Contracts vary in length and are typically "laddered" to provide rate stability
- Details regarding the procurement process, products, and timing are pre-approved
- Cost recovery process is approved by the Commission in advance
- Results are approved within 1-3 business days of solicitation
- Products do not require utility to post collateral
- Usually no significant cost deferrals
- Relatively easy to implement
- Sellers require compensation for the costs and risks that they bear

## Managed Portfolio

Another approach to SOS procurement involves the use of a "managed portfolio," which generally entails purchases of component products of the full requirements supply obligation, most commonly involving block products for energy supplemented with spot market purchases:



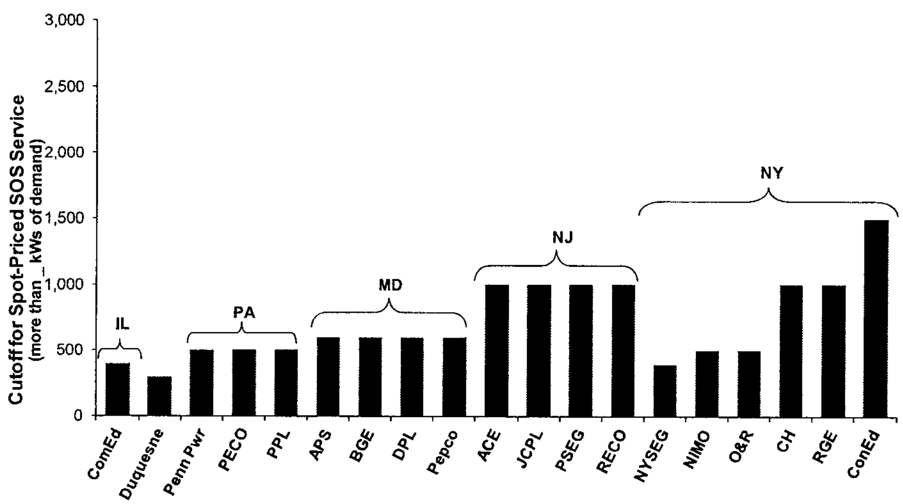

**Key Features**

- Utility purchases component products
- Customers assume a degree of volume, price, and regulatory risks
- Contracts vary in length and are typically "laddered" to provide rate stability
- Cost recovery process is approved by the Commission in advance
- Standard NYMEX block products may require utility to post collateral
- Potential mismatch of supply and demand (i.e., "too much" or "too little"), especially when unfavorable

Note: Some parties consider some portfolios that include full requirements products to be "managed portfolios." For the purpose of clarity in this presentation, the term "managed portfolio" here refers to portfolios that do not include full requirements products and that are not entirely based on spot procurement.

Spot market procurement and pricing based on customer-specific hourly usage has become more prevalent for large C&I customers:

Utilities with Spot-Priced SOS Service for Large C&I Customers

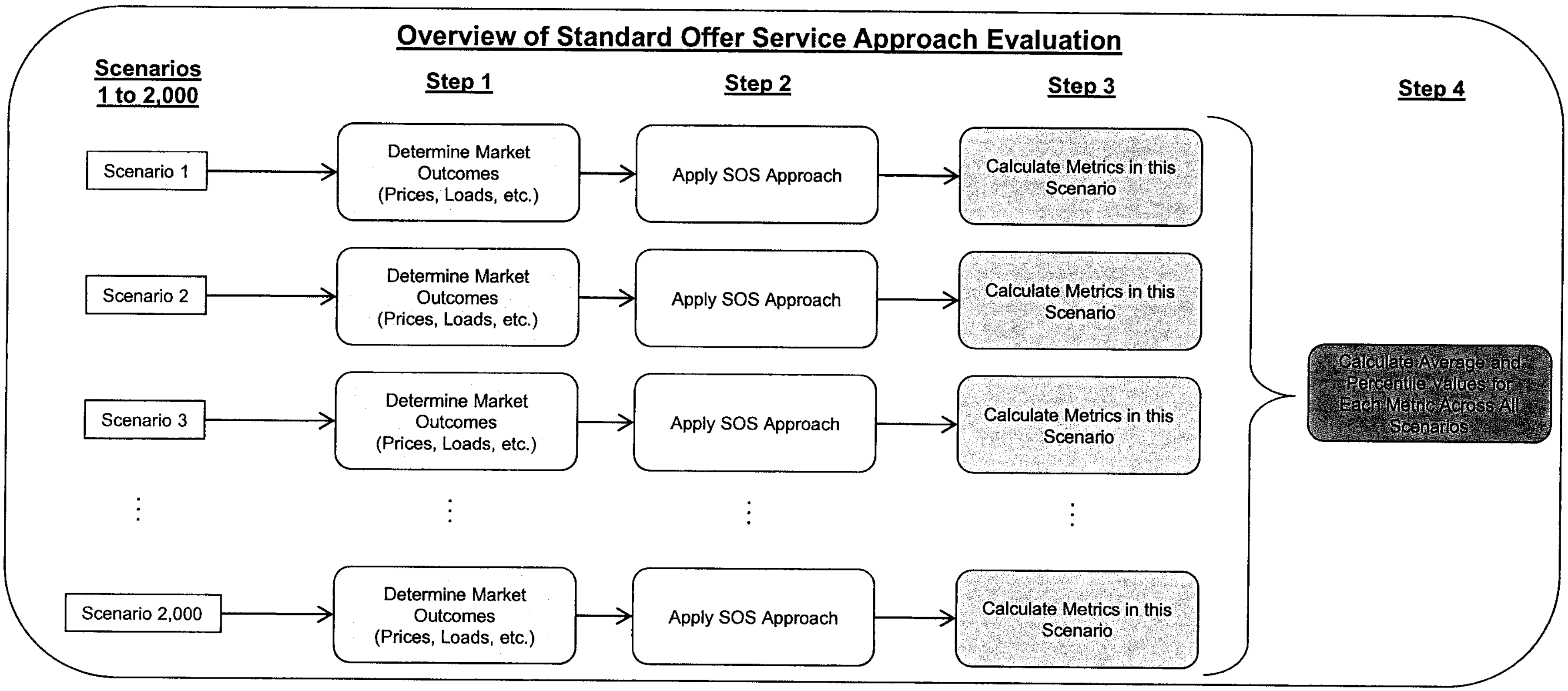



Note: For the purposes of this chart, "spot" includes both day-ahead and real-time pricing.
Note: PECO's spot-priced service has been approved, but is not yet effective.

Key Features

- Real-time or day-ahead energy spot prices
- Promotes efficient customer consumption decisions (e.g., EE and DR)
- Supports retail market development
- Usually no significant cost deferrals
- Generally not considered "acceptable" for small customers due to rate volatility concerns
- Not feasible absent metering / communications / data management

In order to analyze various SOS approaches for mass market customers, we utilized a proprietary Monte Carlo simulation approach to replicate market uncertainty based on actual market data, and modeled and measured the performance of the various SOS approaches:




As part of this analysis, we studied bid prices and component costs for SOS products recently solicited by different utilities.

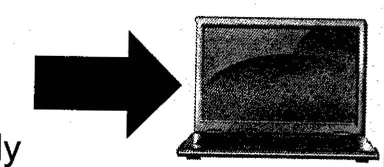
## Application Of Approaches

Our model allows for evaluation of a wide variety of SOS procurement and cost recovery approaches, including:

← Procurement → | Linkage | ← Cost Recovery →

| Product Duration | Product Type | Hedge Target | Laddering* | Retail Rate Adjustments | Deferral Balance Accruals |
|---|---|---|---|---|---|
| 20 yr. | Mix of Products | 100% | 100% | Annually or Longer | Annually |
| 3 yr. | Full Requirements | 75% | | | |
| | | 50% | 50% | Quarterly | |
| 1 yr. | Block | | 33.3% | Monthly | Monthly |
| 6 month | | | | | |
| Hourly | Spot | 0% | 0% | Hourly | None |

Recovered over X months @ Y% interest with or without deferral recovery cap



* Amount of supply procured at any point in time.

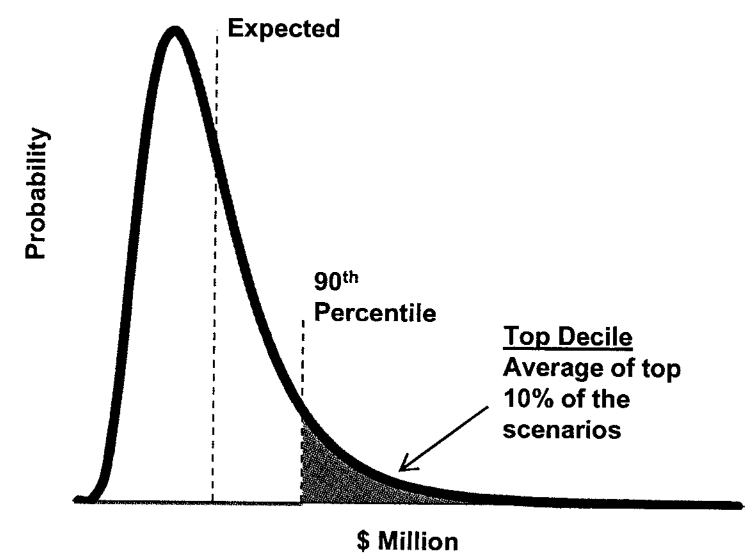
Procurement events, rate adjustments, customer switching decisions, and deferral balance recovery can be modeled to occur at different times.

Each SOS approach was evaluated using the following metrics:

| Category | Metric |
|---|---|
| Metrics Directly Related to Rates | **Expected Rate Level**<br>Average SOS rate level across scenarios |
| | **Supply Cost Surprise**<br>Distribution of difference between actual (ex post) and forecasted (ex ante) supply costs ($MM, $/MWh, %) |
| | **Rate Volatility**<br>Distribution of SOS rate movements:<br>• From one year to the next<br>• "Coefficient of variance" (similar to New York) |
| Metrics Directly Related to Financing/ Liquidity | **Deferral Account Balance**<br>Distribution of accumulated under/(over) collections due to differences between SOS rates and actual supply costs |
| | **Mark-to-Market Exposure**<br>Exposure on block energy contracts (how far fixed-quantity commitments are out-of-market; also potentially relevant to credit requirements) |

- To assess risks, distributions of the metrics were analyzed:

**Deferral Account Balance**




Note: Rates in this presentation refer to the rate for the supply procured, not including gross-ups for line losses, retail taxes, and other administrative costs.

## OUR ANALYSIS — Representative Approaches

While we analyzed many specific SOS approaches/portfolios, our findings can be conveyed through a discussion of three representative SOS approaches/portfolios:

| Type of Approach | Description | Standard Offer Service Rate Determination | Treatment of Deferrals |
|---|---|---|---|
| **Full Requirements** | 1-year full requirements products, in which 1/2 is procured every 6 months | Rates reset every 6 months (ex ante) | No deferrals; rates based on actual costs |
| **Managed Portfolio (Block and Spot)** | Block energy 25% 4-year (1/4 per year), 25% 2-year (1/2 per year), 25% 6-month, Spot (25%) | Rates reset every 6 months (ex ante) | Prior month balance recovered with 2 month lag; $5/MWh recovery cap (i.e., deferral rate adjustment in any month cannot exceed $5/MWh) |
| **Spot** | Procurement based entirely on spot | Rates reset each month (ex post) | No deferrals[1]; rates based on actual costs |

[1] Deferrals may exist to the degree that RTO settlement adjustments are not available when customers' bills are sent.

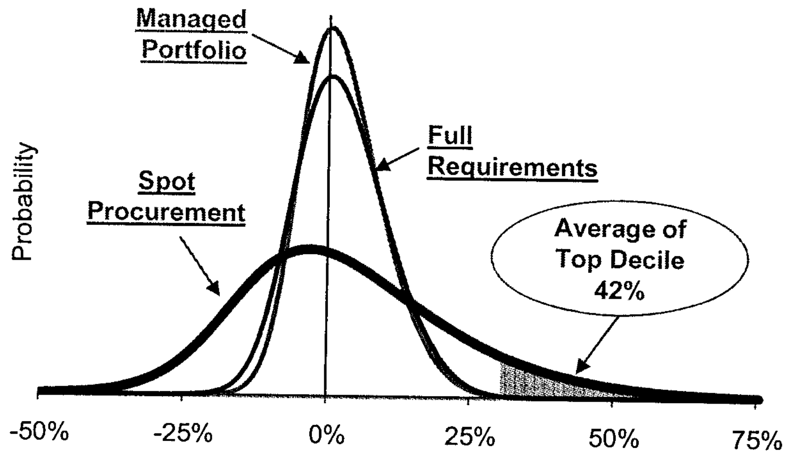
## SUMMARY OF FINDINGS — Spot Procurement

The expected SOS rate under spot procurement is about $2-3/MWh lower than under other approaches, but spot procurement exposes customers to significant rate volatility – annual rate increases across 10 percent of the market scenarios average over 40%:

**Expected Rate Levels**

| Approach | Expected Rate ($ / MWh) | Difference Versus Spot |
|---|---|---|
| Spot | $86.01 | NA |
| Managed Portfolio | $88.22 | +$2.21 |
| Full Requirements | $88.94 | +$2.93 |

**Spot Procurement – High Rate Volatility**
Distribution of Annual Rate Changes (%)




**Spot Procurement**

| | |
|---|---|
| Top Decile Supply Cost Surprise ($MM) | $123 MM |
| Expected Coefficient of Variance (%) | 17% |
| Top Decile Coefficient of Variance (%) | 28% |

Most regulators and small customer representatives consider 100% spot procurement for mass market customers to be “unacceptable”:

- Our studies indicate that no U.S. utilities only offer spot-priced SOS without some form of hedging for mass market customers
- “Unacceptable rate increases” for mass market customers with few competitive alternatives could result in significant cost deferrals

## SUMMARY OF FINDINGS



Both managed portfolio (MP) and full requirements (FR) approaches can reduce customers' exposure to rate volatility, but key differences exist:

| Key Differences | Managed Portfolio | Full Requirements |
|---|---|---|
| **Risks Allocated to Customers** | **Higher**, cost of mistakes/bad market outcomes borne by customers | **Lower**, cost of mistakes/bad market outcomes borne by FR suppliers during delivery period |
| **Expected Rate Level** | **Lower** | **Higher**, by about $1/MWh |
| **Supply Cost Surprise** | **Higher**, supply costs exceed ex ante forecasts by over $40 MM on average across 10 percent of the scenarios due to unhedged positions and load uncertainty | **Lower**, FR suppliers assume more risks |
| **Deferral Account Balances** | **Higher**, could become large ($50 MM or more) depending on several key variables | **Minimal** (if no spot included) |
| **Effect of Additional Costs and Risks Not Modeled** | **Higher**, would increase costs and risks of an MP approach (e.g., uncertainty regarding capacity, ancillary services, and RPS costs, greater-than-assumed customer switching, etc.) | **Lower,** risks assumed by FR suppliers |
| **Internal Resources** | **Higher**, may require additional staff to manage portfolio and ongoing Commission oversight | **Lower**, risk management functions put out for competitive bid |

## Allocation Of Risks

SOS costs and risks remain in either approach, but who bears these costs and risks is different in each approach:

**Standard offer service involves many costs and risks:**

- Mismatch between revenues and supply costs
- Customer migration
- Unexpected congestion
- Uncertain load and price levels
- Uncertain load and price shapes
- Adverse selection (competitors can select who they serve; SOS supplier cannot)
- Collateral requirements (potentially)
- Potential changes in laws and regulations
- Administrative expenses

**These costs and risks remain in either approach.**

**Full Requirements**
**Suppliers bear costs and risks during the delivery period, but require compensation to do so**

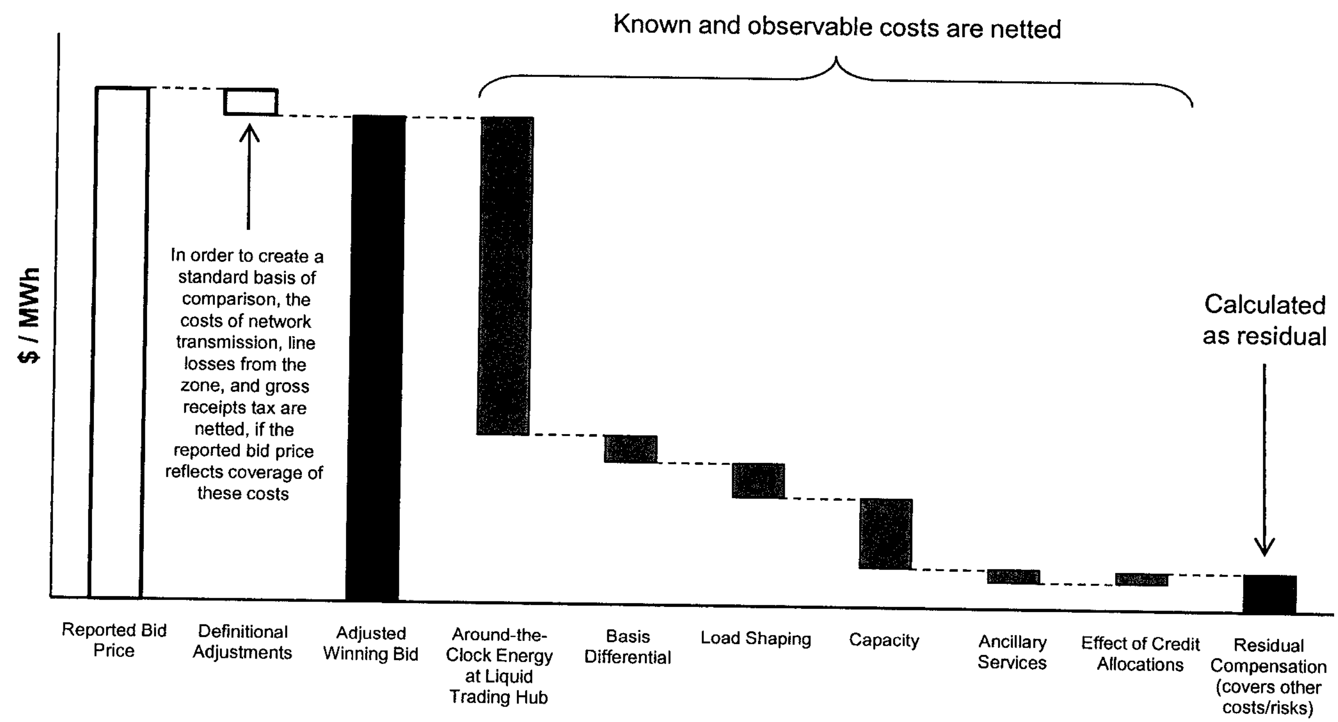
**Managed Portfolio**
**Customers are exposed to costs and risks to a higher degree**

Our analysis involved a thorough look at the trade-off between compensation and risk.

## FULL REQUIREMENTS — Modeling FR Product Pricing

In order to incorporate full requirements product pricing in our analysis, for full requirements SOS supply products recently solicited by different utilities, we used market information to develop estimates of expectations (at the time of the solicitation) regarding the costs of components of the full requirements supply product and compared these costs to the actual prices of the full requirements product:

**Illustrative Full Requirements Product Price Analysis**

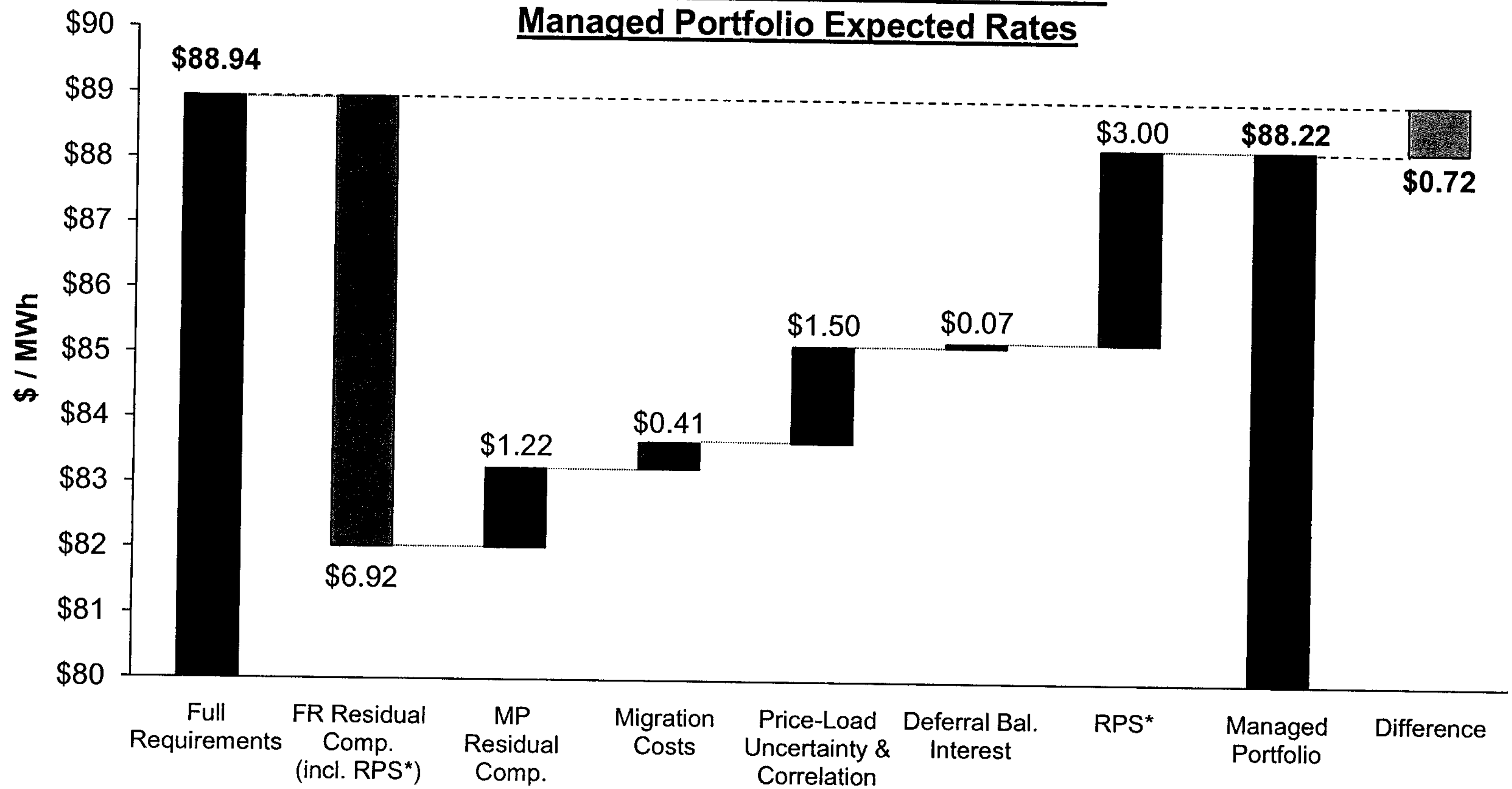



The residual compensation required by full requirements product suppliers, observed through this study of actual product solicitations, was incorporated in our quantitative analysis of SOS approaches.

The difference between the expected SOS rate under the FR approach versus under the MP approach is about $1/MWh:

**Comparison of Full Requirements and Managed Portfolio Expected Rates**



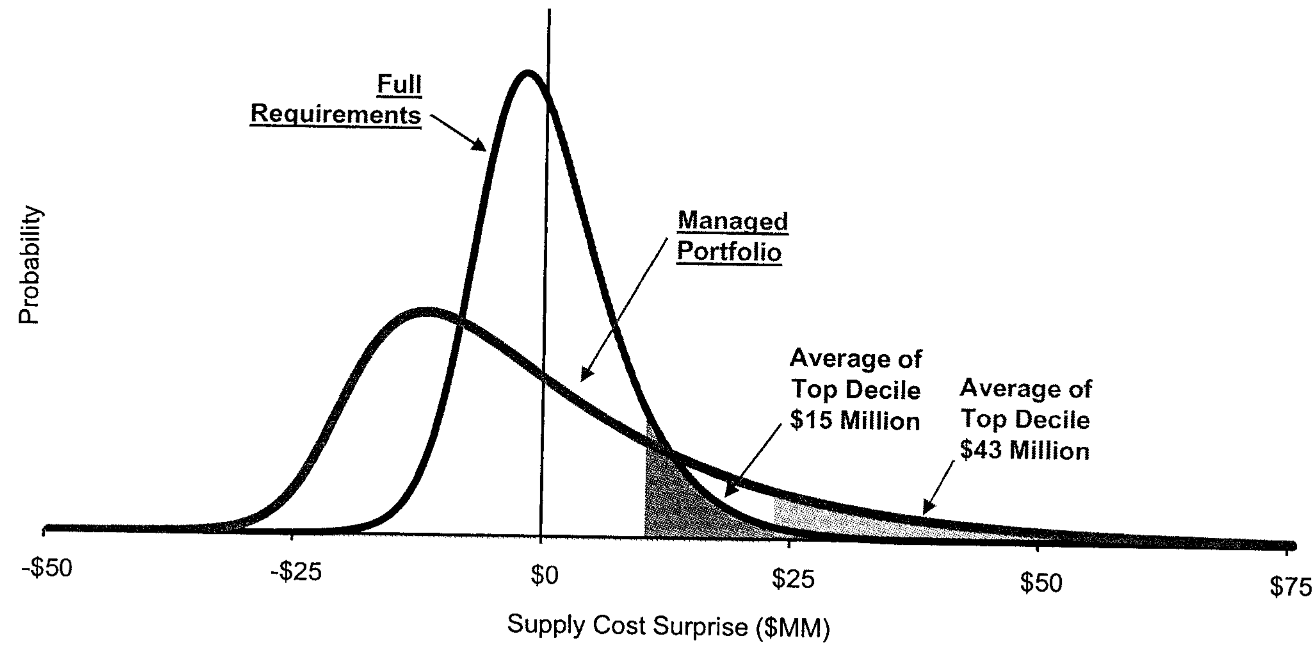

* Under *all* of the procurement approaches that were modeled, the model adjusts the pricing of the supply procured to reflect an RPS cost of $3/MWh *going forward*.

## MP vs. FR

## Supply Cost Surprise

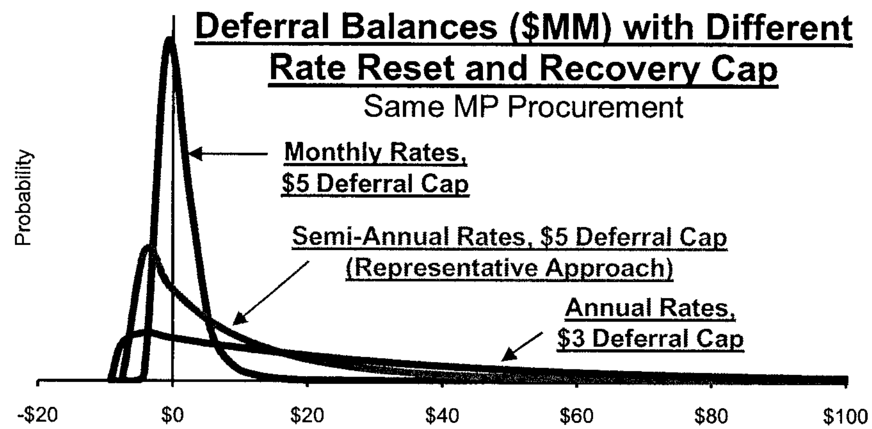
But the MP approach could result in higher unexpected increases in SOS costs, due to unhedged positions and/or unpredictable SOS load levels:

**Distribution of Supply Cost Surprise ($MM)**




For example, risks associated with price movements such as the 2000 price spikes in California or the 1998-1999 price spikes in the Eastern U.S. would be absorbed by FR suppliers during the supply product delivery period, but customers would absorb more of this risk under an MP approach.

MP approaches also involve deferral balances that could become large, and are impacted by how the deferral recovery mechanisms are designed, approved, and implemented:




| Deferral Account Balances ($MM) | Semi-Annual Rates, $5 Deferral Recovery Cap | Annual Rates, $3 Deferral Recovery Cap | Monthly Rates, $5 Deferral Recovery Cap |
|---|---|---|---|
| Expected Value ($MM) | $10 MM | $28 MM | $1 MM |
| Average of Top Decile ($MM) | $57 MM | $113 MM | $9 MM |

**Key Variables in Mechanism Design**
- Frequency of rate reset (based on forecasted future costs)
- Frequency of rate reconciliation (based on actual costs and revenues)
- Recovery period
- Interest on deferral balances
- Deferral recovery cap
- Maximum deferral balance

**Wellsboro Example**
- Based on its unexpected costs incurred under its MP approach in early 2008, Wellsboro Electric reported that supply rates could be twice expected levels without deferrals. As a result, the period for recovery of the unexpected costs was extended from three to twelve months.

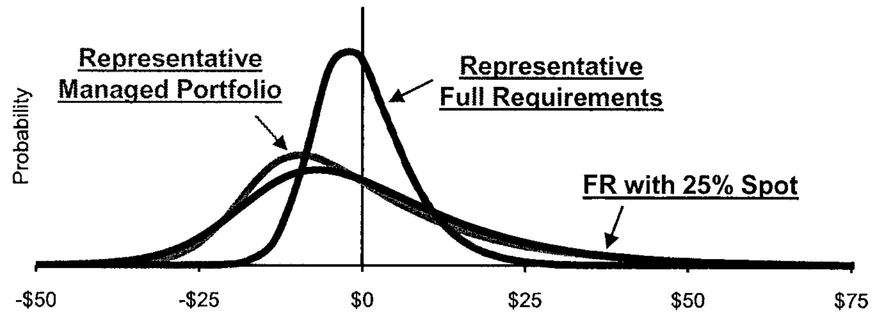
Using an FR approach, supply costs are known when rates are established, therefore no (or minimal) deferrals are required unless spot purchases are also included in the plan.

# MP vs. FR — FR with Spot

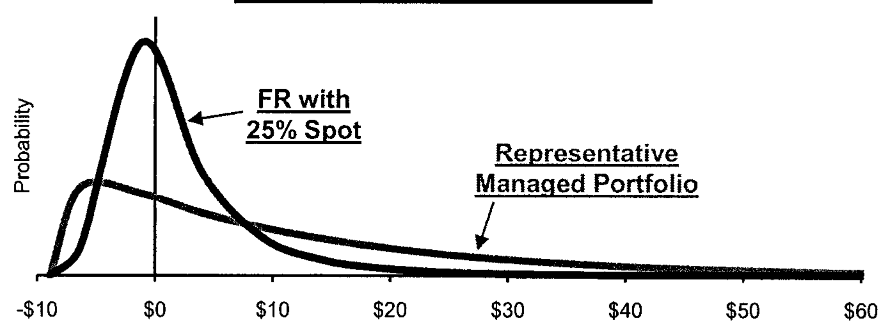
If the FR approach were modified to include 25% spot purchases, the expected rate level would decrease, but the risk associated with supply cost surprise and deferral balances would increase:

| Expected Rate Level ($/MWh) | |
|---|---|
| Approach | Average of Top Decile |
| Representative MP | $88.22 |
| Representative FR | $88.94 |
| FR with 25% Spot | $88.21 |

Supply Cost Surprise ($MM)




Deferral Balances ($MM)




| Supply Cost Surprise ($MM) | |
|---|---|
| Approach | Average of Top Decile |
| Representative MP | $43 MM |
| Representative FR | $15 MM |
| FR with 25% Spot | $37 MM |

| Deferral Account Balances ($MM) | |
|---|---|
| Approach | Average of Top Decile |
| Representative MP | $57 MM |
| Representative FR | $0 MM |
| FR with 25% Spot | $18 MM |

Some utilities have adopted an approach involving a mix of full requirements products and spot purchases (although 25% spot is higher than levels generally adopted for mass market customers).

## Additional Risks

There are additional costs and risks that were not modeled in the quantitative evaluation that would increase the costs and risks of an MP approach:

- Increased administrative costs (e.g., portfolio management staff and systems, regulatory proceedings and/or interaction with regulators, etc.)
- Uncertainty regarding capacity, ancillary services, and RPS costs[1]
- Greater-than-assumed customer switching (e.g., due to additional potential for new technologies, regulatory policies, opt-out customer aggregation, etc.)
- Imputed debt costs

In contrast, full requirements product suppliers compete on price to manage these and other risks, and absorb the costs of any mistakes.

[1] The model assumes constant \$/MWh capacity, RPS, and ancillary services costs across all scenarios. Modeling uncertainty around these other variables would make an MP approach less attractive relative to what was quantified in this presentation.

# SUMMARY OF FINDINGS

- 100% spot procurement would expose mass market customers to significant rate volatility and is not acceptable to most regulators at this time
- Both a managed portfolio and a full requirements approach can reduce customers' exposure to rate volatility, but key differences exist:

| Key Differences | Managed Portfolio | Full Requirements |
|---|---|---|
| Risks Allocated to Customers | Higher | Lower |
| Expected Rate Level | Lower | Higher |
| Supply Cost Surprise | Higher | Lower |
| Deferral Account Balances | Higher | Minimal (if no spot included) |
| Effect of Additional Costs and Risks Not Modeled | Higher | Lower |
| Internal Resources | Higher | Lower |

# Appendix

# SUMMARY OF METRICS

# More Approaches

| Description of Approach | | | | Comparison of Performance Metrics | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Product Kind | Product Type | Hedge Ratio (%) | Rate Period | 2012 SOS Rate Levels ($/MWh) | Supply Cost Surprise ($MM) | Supply Cost Surprise ($/MWh) | Supply Cost Surprise (%) | Deferral Account Balance ($MM) | Annual Rate Movement (%) | Coefficient of Variation (%) | Customer Switching (%) | Mark-to-Market Exposure ($MM) |
| Ten-Year Laddered | Block Energy | 100% | Annual | $92.37 ($84.06 / $105.89) | $0 (-$14 / $29) | $0.00 (-$4.03 / $10.51) | 0.0% (-4.5% / 11.8%) | $9 (-$1 / $51) | 1.8% (-3.7% / 8.8%) | 2.0% (0.0% / 3.5%) | 16% (0% / 57%) | -$31 (-$421 / $213) |
| Five-Year Laddered | Block Energy | 100% | Annual | $89.90 ($76.28 / $108.77) | $0 (-$13 / $28) | $0.00 (-$3.48 / $8.63) | 0.0% (-4.0% / 10.0%) | $7 (-$1 / $41) | 2.0% (-5.2% / 10.6%) | 2.1% (0.0% / 3.6%) | 12% (0% / 44%) | -$5 (-$169 / $113) |
| | | 75% | Annual | $88.60 ($72.41 / $111.25) | $0 (-$23 / $43) | $0.00 (-$6.00 / $10.14) | 0.0% (-6.5% / 11.4%) | $14 (-$4 / $77) | 2.1% (-6.6% / 13.2%) | 2.7% (0.0% / 5.3%) | 11% (0% / 40%) | -$4 (-$126 / $84) |
| Three-Year Laddered | Full Requirements | 100% | Annual | $92.19 ($71.87 / $118.74) | $0 ($0 / $0) | $0.00 ($0.00 / $0.00) | 0.0% (0.0% / 0.0%) | $0 ($0 / $0) | 1.8% (-7.2% / 12.4%) | 0.0% (0.0% / 0.0%) | 13% (1% / 36%) | $0 ($0 / $0) |
| | | 75% | Annual | $90.65 ($69.47 / $119.18) | $0 (-$20 / $29) | $0.00 (-$5.33 / $6.46) | 0.0% (-5.6% / 7.0%) | $3 (-$4 / $24) | 1.9% (-8.8% / 14.0%) | 3.3% (0.5% / 5.7%) | 10% (1% / 31%) | $0 ($0 / $0) |
| | Block Energy | 100% | Annual | $89.61 ($69.67 / $115.89) | $0 (-$12 / $27) | $0.00 (-$3.20 / $8.09) | 0.0% (-3.7% / 9.2%) | $7 (-$1 / $39) | 1.8% (-8.2% / 13.1%) | 2.1% (0.0% / 3.6%) | 10% (0% / 38%) | $4 (-$82 / $74) |
| | | 75% | Annual | $88.63 ($67.69 / $116.87) | $0 (-$22 / $43) | $0.00 (-$5.65 / $10.03) | 0.0% (-6.2% / 11.3%) | $14 (-$3 / $77) | 2.1% (-8.4% / 14.9%) | 2.7% (0.0% / 5.1%) | 11% (0% / 41%) | $3 (-$61 / $55) |
| One-Year Laddered | Full Requirements | 100% | Semi-Annual | $88.94 ($65.66 / $121.55) | $0 (-$11 / $15) | $0.00 (-$2.91 / $3.46) | 0.0% (-3.3% / 3.7%) | $0 ($0 / $0) | 2.0% (-11.2% / 17.0%) | 2.1% (0.2% / 5.6%) | 8% (0% / 24%) | $0 ($0 / $0) |
| | | 100% | Annual | $88.99 ($65.43 / $122.45) | $0 (-$11 / $15) | $0.00 (-$2.87 / $3.47) | 0.0% (-3.2% / 3.7%) | $2 (-$3 / $15) | 2.1% (-12.8% / 20.2%) | 2.3% (0.3% / 4.7%) | 8% (1% / 24%) | $0 ($0 / $0) |
| | | 100% | Monthly | $88.94 ($65.66 / $121.55) | $0 (-$11 / $15) | $0.00 (-$2.91 / $3.46) | 0.0% (-3.3% / 3.7%) | $0 ($0 / $0) | 2.0% (-11.2% / 17.0%) | 2.1% (0.2% / 5.6%) | 8% (0% / 24%) | $0 ($0 / $0) |
| | | 75% | Semi-Annual | $88.21 ($64.12 / $121.76) | $0 (-$26 / $37) | $0.00 (-$6.94 / $8.30) | 0.0% (-7.6% / 9.2%) | $2 (-$4 / $18) | 2.1% (-12.7% / 18.7%) | 4.1% (1.9% / 7.3%) | 6% (0% / 21%) | $0 ($0 / $0) |
| | Block Energy | 100% | Semi-Annual | $88.02 ($64.75 / $120.65) | $0 (-$17 / $30) | $0.00 (-$4.25 / $7.03) | 0.0% (-4.9% / 7.7%) | $4 (-$1 / $26) | 2.0% (-11.3% / 17.2%) | 3.3% (1.3% / 6.6%) | 6% (0% / 25%) | $6 (-$27 / $37) |
| | | 75% | Semi-Annual | $87.59 ($63.51 / $121.02) | $0 (-$28 / $49) | $0.00 (-$7.11 / $10.90) | 0.0% (-8.0% / 12.4%) | $11 (-$3 / $62) | 2.2% (-12.2% / 19.1%) | 4.0% (1.1% / 7.2%) | 8% (0% / 35%) | $5 (-$20 / $28) |
| Spot | None | 0% | Monthly Ex Post | $86.01 ($56.77 / $127.32) | $0 (-$90 / $123) | $0.00 (-$21.36 / $25.78) | 0.0% (-23.7% / 29.8%) | $0 ($0 / $0) | 3.5% (-26.0% / 42.1%) | 16.9% (9.4% / 27.6%) | 0% (0% / 0%) | $0 ($0 / $0) |
| | | 0% | Monthly Ex Ante | $86.03 ($56.68 / $126.55) | $0 (-$87 / $118) | $0.00 (-$21.37 / $25.81) | 0.0% (-23.8% / 29.9%) | $8 (-$4 / $34) | 3.6% (-26.3% / 41.2%) | 19.0% (10.6% / 29.9%) | 3% (0% / 15%) | $0 ($0 / $0) |
| | | 0% | Quarterly Ex Ante | $86.11 ($56.74 / $125.11) | $0 (-$82 / $108) | $0.00 (-$21.41 / $25.89) | 0.0% (-23.8% / 30.0%) | $18 (-$9 / $76) | 3.6% (-24.7% / 40.1%) | 16.1% (6.0% / 29.9%) | 9% (0% / 42%) | $0 ($0 / $0) |
| Hybrid / Mixed | Block Energy[1] | 75% | Semi-Annual | $88.22 ($66.68 / $117.88) | $0 (-$23 / $43) | $0.00 (-$5.92 / $9.83) | 0.0% (-6.6% / 11.1%) | $10 (-$3 / $57) | 2.2% (-9.0% / 16.1%) | 3.6% (1.1% / 6.5%) | 9% (0% / 36%) | $5 (-$47 / $47) |
| | Block Energy[1] | 75% | Annual | $88.23 ($66.58 / $117.88) | $0 (-$22 / $42) | $0.00 (-$5.76 / $9.83) | 0.0% (-6.5% / 11.0%) | $16 (-$4 / $86) | 2.3% (-9.7% / 16.9%) | 2.6% (0.0% / 5.5%) | 12% (0% / 46%) | $5 (-$46 / $46) |
| | Block Energy[1] | 75% | Monthly | $88.04 ($66.63 / $117.86) | $0 (-$24 / $44) | $0.00 (-$5.89 / $9.59) | 0.0% (-6.5% / 10.8%) | $1 (-$2 / $9) | 2.2% (-8.8% / 16.6%) | 5.9% (2.6% / 10.8%) | 5% (0% / 18%) | $5 (-$48 / $49) |
| | Block Energy[2] | 75% | Annual | $88.98 ($70.98 / $114.13) | $0 (-$24 / $42) | $0.00 (-$6.42 / $9.85) | 0.0% (-7.1% / 11.0%) | $16 (-$3 / $85) | 3.6% (-9.3% / 19.0%) | 3.4% (0.6% / 6.6%) | 14% (0% / 56%) | -$7 (-$129 / $78) |

[1] 25% four-year block energy, 25% two-year block energy, 25% six-month block energy, 25% spot.
[2] 25% ten-year block energy, 25% four-year block energy, 25%, one-year block energy, 25% spot.

## MARKET OUTCOMES

## Monte Carlo Approach

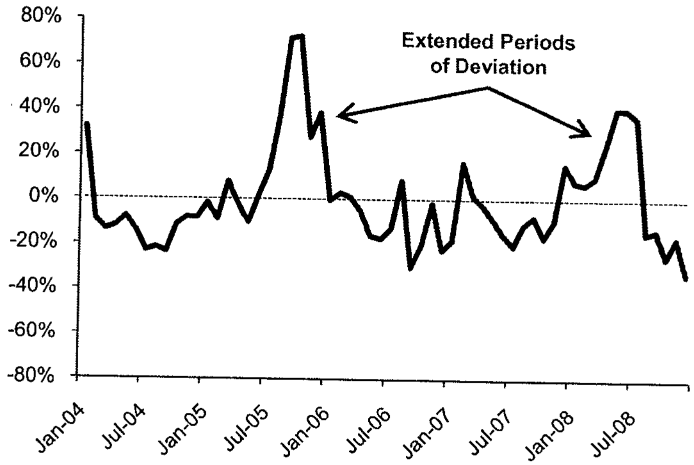
- Each SOS approach is evaluated by examining how the approach would perform under a wide variety of market conditions
- Creating these potential 'states of the world' is a critical part of the evaluation process
  - NorthBridge utilizes a proprietary Monte Carlo simulation approach to replicate the types of uncertainty in energy prices, total load, and load-weighting gross-ups we have seen historically[1]
  - This approach generates correlated[2] scenarios of potential outcomes for energy prices, total load, and load-weighting gross-ups to which we can apply different SOS approaches and observe the range of risks and benefits
- Scenarios of market outcomes are centered around current forecasts or expectations for energy prices, total load, and load-weighting gross-ups, but the intent behind the quantitative evaluation of SOS approaches is to illustrate the relative differences in cost and risk between different approaches rather than identify the precise costs associated with a specific approach

[1] Capacity prices, ancillary services costs, and RPS costs were not modeled to be uncertain in this analysis.
[2] Correlations between energy prices, total load, and load-weighting gross-ups are based on historical relationships.

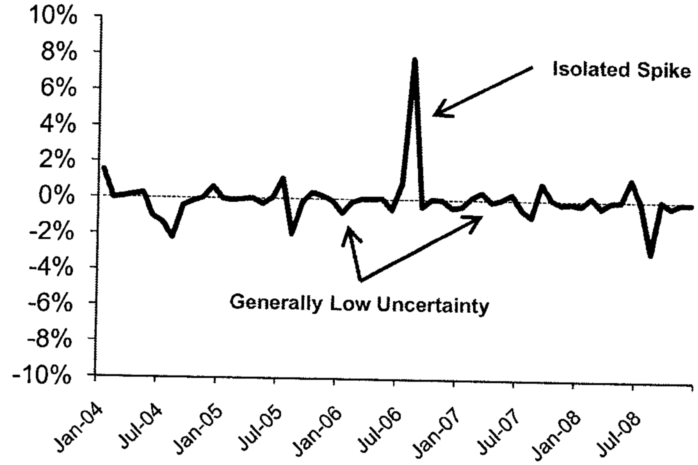
# Characteristics of Volatility

- We generate scenarios to help us observe how different SOS approaches would perform under different conditions (i.e. what sort of rate volatility, rate levels, deferral balances, etc. would they yield?)
- We need scenarios to exhibit the same types of characteristics (e.g. volatility and mean reversion) we have seen in the past:

**% Deviation of the Monthly Mass-Hub Peak Energy Price From Seasonal Pattern and Long-Term Trend**




**% Deviation of the Monthly Mass-Hub Peak Load-Weighting Gross-Up From Seasonal Pattern and Long-Term Trend**




- Energy prices tend to be quite volatile and may take considerable time to mean-revert back to a long-term trend
- Gross-up levels are generally far less volatile and mean revert to long-term trends very quickly, but can also exhibit some extreme 'events'

- In order to create scenarios of what might happen in the future, we use a model of how the underlying process (i.e. prices or load) evolve over time
- The model used in this analysis is a three factor mean reverting model with stochastic volatility, and is a variant of the Random Walk / Geometric Brownian Motion (GBM) model commonly used in quantitative finance

Stochastic Differential Equations Defining the Underlying Processes[1]

$$dP = (P - \overline{P}) \cdot h_p \cdot dt + \sigma_p \cdot V \cdot P \cdot dW + drift$$

$$dV = (V - \overline{V}) \cdot h_v \cdot dt + \sigma_v \cdot V \cdot dZ$$

$$r(dW, dZ) = \beta$$

(*dW* and *dZ* are correlated normally-distributed random variables)

$dP$ = Change in price
$P$ = Price in prior period
$\overline{P}$ = Long term average price
$h_p$ = Rate of mean reversion of price
$dt$ = Time elapsed since prior period
$\sigma_p$ = Basecase marginal volatility of price
$dW$ = Normally distributed random variable
$dV$ = Change in volatility
$V$ = Volatility in prior period
$\overline{V}$ = Long term average volatility
$h_v$ = Rate of mean reversion in volatility
$\sigma_v$ = Basecase marginal volatility of volatility
$dZ$ = Normally distributed random variable
$\beta$ = Correlation between $dW$ and $dZ$

- NorthBridge has developed a proprietary set of tools using a maximum likelihood estimation technique to ‘fit’ the model above to match price / load characteristics and properties observed historically

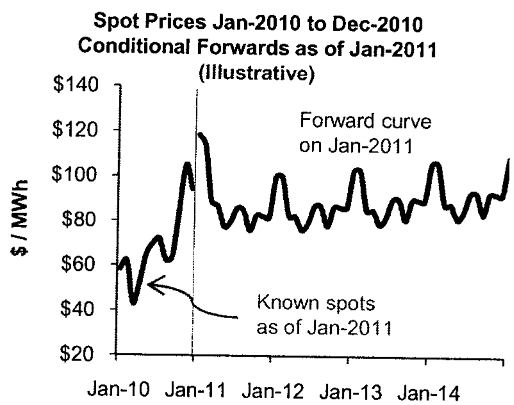
[1] This model is a variation of the Dixit-Pindyck mean-reverting random walk model used for simulating commodity price movements. The principal difference is the addition of the term for stochastic volatility.

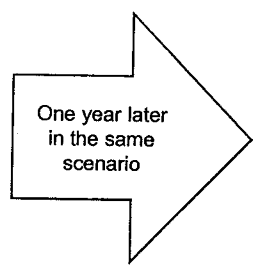
# MARKET OUTCOMES

## Scenario Components

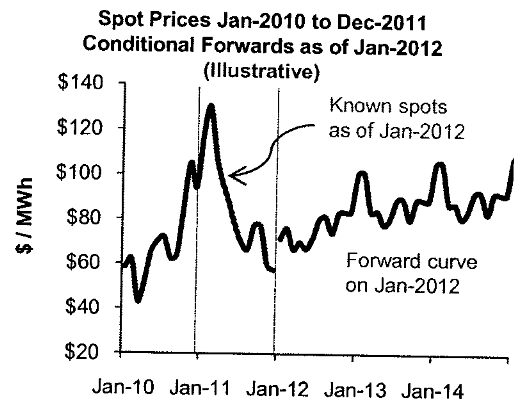
- Scenarios illustrate the uncertainty associated with variables such as wholesale market prices, total load levels, and load-weighting gross-up factors
- Each scenario consists of (1) a time-series of ultimate spot outcomes, and (2) conditional forecasts (i.e. in a given scenario, what would most likely be the forecast at a specific observation date for future delivery periods)

- We might observe spot prices from Jan-2010 through Dec-2010 and then ask what the forward curve might look like as of Jan-2011:



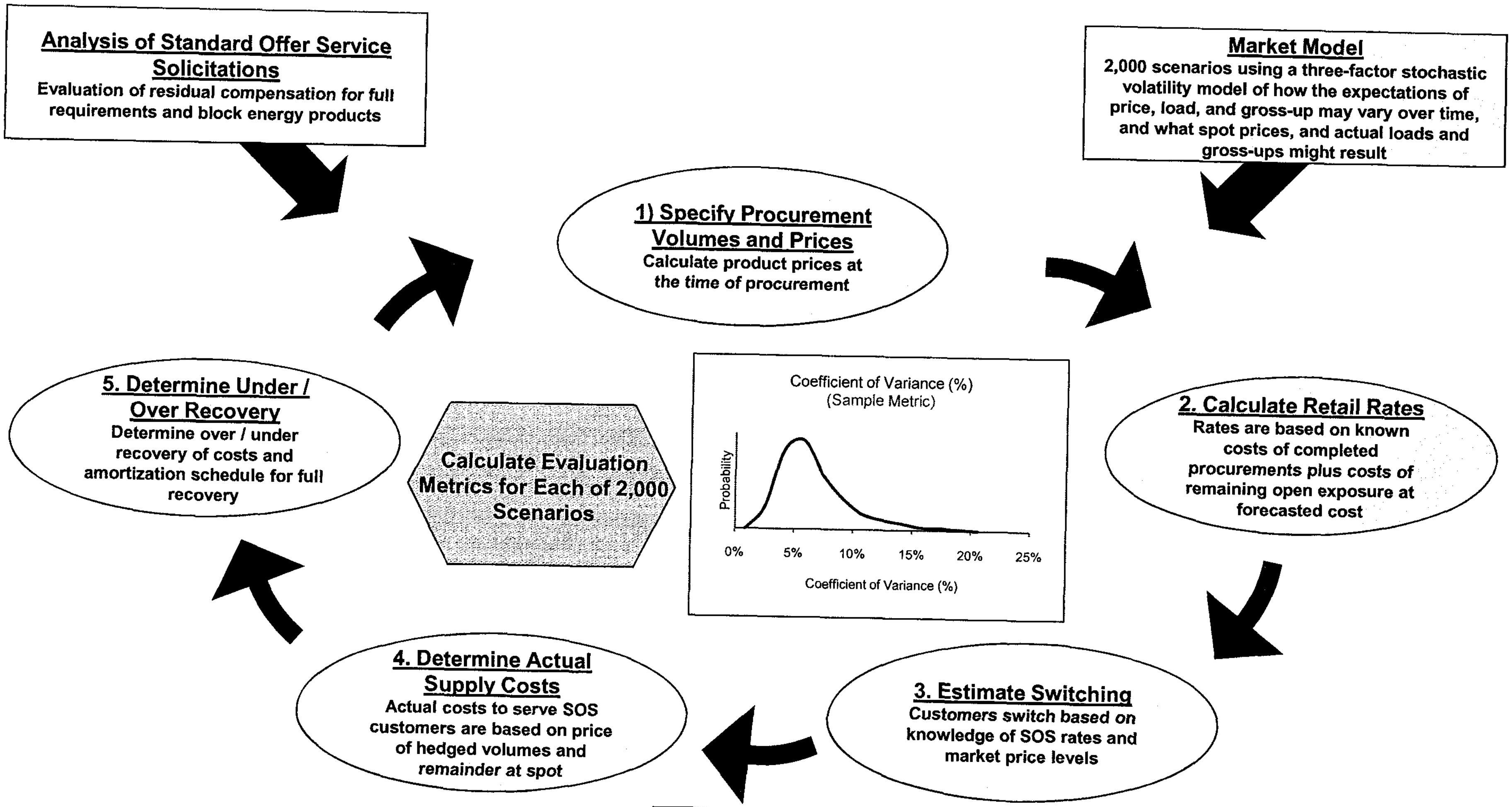




- In that same scenario, we can then track what might have happened during 2011 and then reassess the forward curve as of Jan-2012:



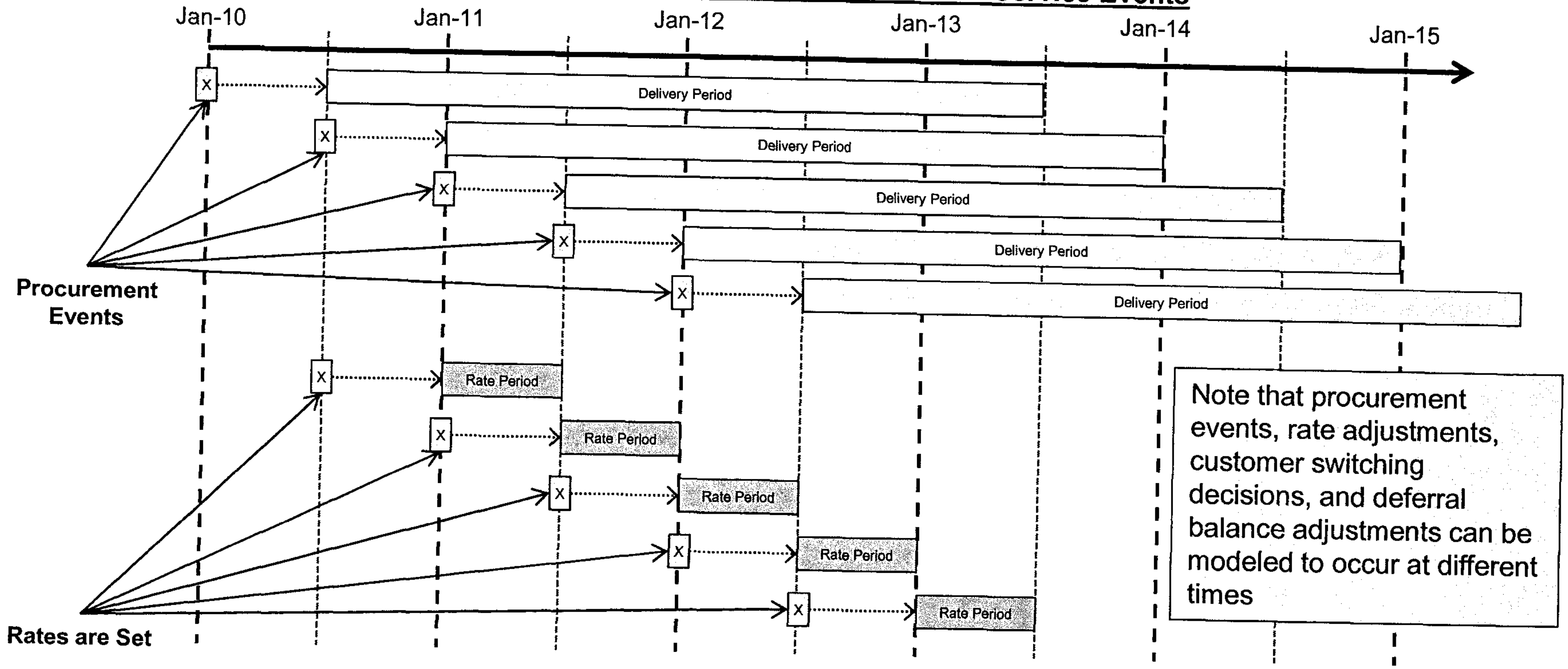
# APPLICATION OF APPROACHES — Model Overview

Several steps are needed to analyze the performance of SOS approaches under the scenarios:



In each scenario, the model applies the SOS approach, procuring products, setting rates, calculating actual costs and amortizing over/under recoveries as appropriate:

**Hypothetical Schedule of Standard Offer Service Events**




All actions (e.g. entering into hedges or setting rates) are done only with the information available at the time (i.e. using conditional forecasts), just as would be the case in the real world.

## APPLICATION OF APPROACHES — Determine Procurements

- Each time a procurement event is scheduled, hedge targets and conditional forecasts of retained load are compared to existing hedges; incremental purchases are made at conditional forward prices:

**Illustrative Block Energy Procurement Product Price Calculation**

| Delivery Month | Jan-11 | Feb-11 | Mar-11 | Apr-11 | May-11 | Jun-11 | Jul-11 | Aug-11 | Sep-11 | Oct-11 | Nov-11 | Dec-11 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Total Forecasted Load (MWh) | 354,272 | 291,862 | 286,682 | 256,802 | 246,598 | 440,393 | 436,106 | 388,879 | 327,210 | 269,360 | 304,062 | 365,284 |
| Hedge Target (%) | 100% | 100% | 100% | 100% | 100% | 100% | 50% | 50% | 50% | 50% | 50% | 50% |
| Existing Hedges (MWh) | 159,400 | 131,300 | 129,000 | 115,600 | 111,000 | 198,200 | 0 | 0 | 0 | 0 | 0 | 0 |
| Incremental Purchases (MWh) | 194,872 | 160,562 | 157,682 | 141,202 | 135,598 | 242,193 | 218,053 | 194,439 | 163,605 | 134,680 | 152,031 | 182,642 |
| Market Price ($ / MWh) | $60.34 | $60.34 | $51.62 | $51.62 | $48.74 | $50.43 | $55.92 | $55.92 | $50.10 | $56.24 | $56.24 | $56.24 |

| | |
|---|---|
| Total Cost ($MM) | $113.4 |
| Total Volume (TWh) | 2.1 |
| Product Price ($ / MWh) | **$54.56** |

- The prices received for different products may include residual compensation (for costs/risks) consistent with historical market evidence for similar transactions

# APPLICATION OF APPROACHES — Determine Rates

- Rates are determined by calculating the total forecasted cost attributable to SOS customers during the delivery period, including any cost/benefit from hedged volumes:

**Illustrative Standard Offer Service Rate Calculation**

| Delivery Month | Jan-11 | Feb-11 | Mar-11 | Apr-11 | May-11 | Jun-11 | Jul-11 | Aug-11 | Sep-11 | Oct-11 | Nov-11 | Dec-11 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Total Forecasted Load (MWh) | 336,559 | 277,269 | 272,348 | 243,962 | 234,268 | 418,374 | 414,301 | 369,435 | 310,850 | 255,892 | 288,859 | 347,020 |
| Forecasted ATC Price ($ / MWh) | $54.31 | $54.31 | $46.45 | $46.45 | $43.86 | $45.38 | $50.33 | $50.33 | $45.09 | $50.62 | $50.62 | $50.62 |
| Forecasted Price-Load Gross Up (%) | 5.79% | 11.95% | 7.94% | 7.28% | 6.09% | 10.56% | 9.87% | 11.52% | 10.95% | 10.98% | 8.54% | 9.23% |
| Forecasted Spot Cost ($MM) | $19.34 | $16.86 | $13.66 | $12.16 | $10.90 | $20.99 | $22.91 | $20.74 | $15.55 | $14.37 | $15.87 | $19.19 |
| | | | | | | | | | | | | |
| Hedged Volume (MWh) | 354,272 | 291,862 | 286,682 | 256,802 | 246,598 | 440,393 | 218,053 | 194,439 | 163,605 | 134,680 | 152,031 | 182,642 |
| Hedged Price ($ / MWh) | $54.56 | $54.56 | $54.56 | $54.56 | $54.56 | $54.56 | $54.56 | $54.56 | $54.56 | $54.56 | $54.56 | $54.56 |
| Benefit (Cost) of Hedge ($MM) | -$0.09 | -$0.07 | -$2.32 | -$2.08 | -$2.64 | -$4.04 | -$0.92 | -$0.82 | -$1.55 | -$0.53 | -$0.60 | -$0.72 |

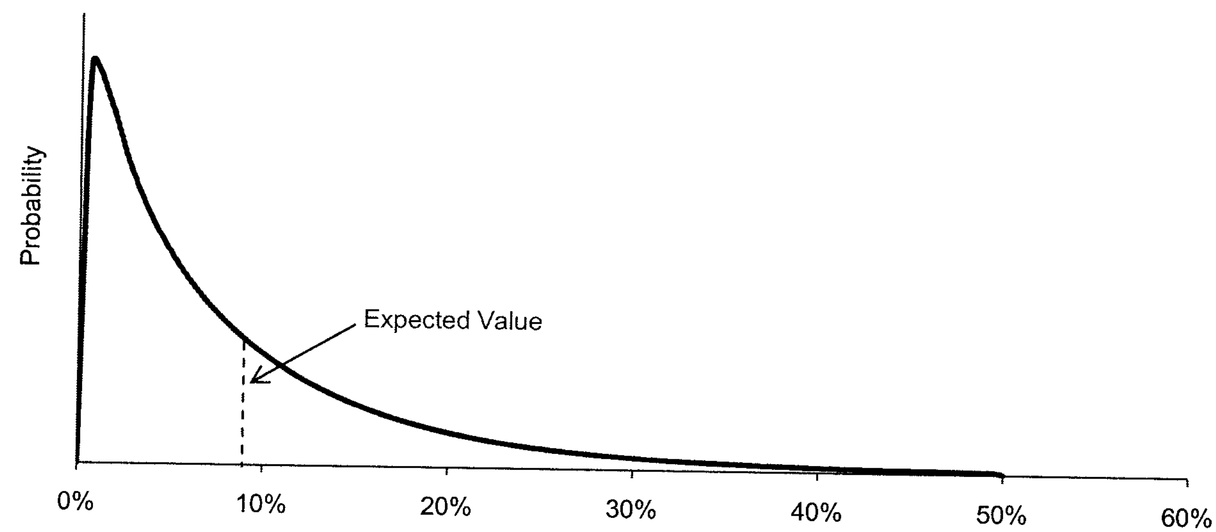
| | |
|---|---|
| Total Forecasted Cost ($MM) | $218.92 |
| Total Forecasted Volume (TWh) | 3.77 |
| | |
| Energy ($ / MWh) | $58.08 |
| Capacity ($ / MWh) | $10.00 |
| Ancillary ($ / MWh) | $3.00 |
| Renewable Energy Credits ($ / MWh) | $3.00 |
| SOS Rate ($ / MWh) | **$74.08** |

- This rate only includes forward-looking cost components; recovery of deferral balances is handled separately

## APPLICATION OF APPROACHES — Customer Switching

- The modeled customer switching dynamic produces a distribution of switching outcomes as follows under one of the SOS approaches:

**Customer Switching at EOY 2014**
**Illustrative**



# APPLICATION OF APPROACHES — Deferral Accounts

- At the end of each simulated month, the model calculates the amount by which the utility's costs differ from revenues:

**Illustrative Cost Under / (Over) Recovery**

| Month | Jan-11 |
|---|---|
| Actual SOS Load (TWh) | 371,986 |
| SOS Rate ($ / MWh) | $74.08 |
| Actual Revenue ($MM) | $27.6 |
| ATC Energy ($ / MWh) | $66.37 |
| Price-Load Gross-Up (%) | 6.03% |
| Shaped Energy ($ / MWh) | $70.38 |
| Capacity ($ / MWh) | $10.00 |
| Ancillary ($ / MWh) | $3.00 |
| Renewable Energy Credits ($ / MWh) | $3.00 |
| Actual Cost ($ / MWh) | $86.38 |
| Actual Cost ($MM) | $32.1 |
| Under / (Over) Collection ($MM) | $4.6 |

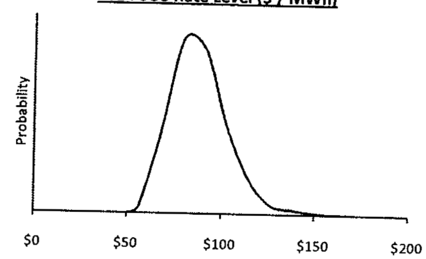
- In this month, actual costs exceeded revenues by $4.6MM
- Any over / under recovery is amortized over future months based on an established schedule as a separate rate rider (e.g. prior month balance recovery with two month delay, potentially subject to a recovery cap)
- This rider is independent of the rates set on the basis of forecasted future costs

# METRICS

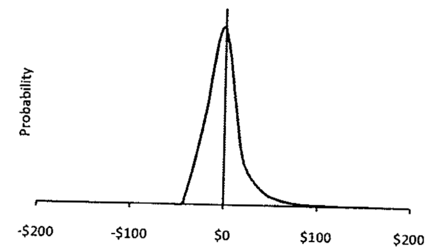
## Distributions

Metrics are calculated in each scenario and transformed into distributions which are used to calculate expected values and percentiles:

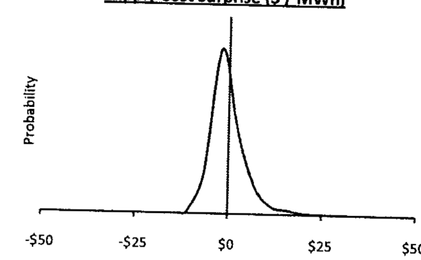
2014 SOS Rate Level ($ / MWh)



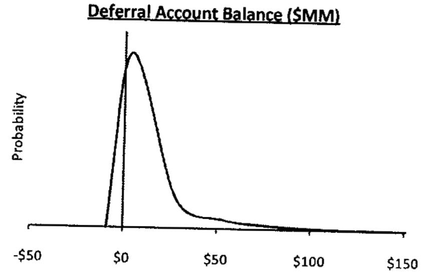

Supply Cost Surprise ($MM)



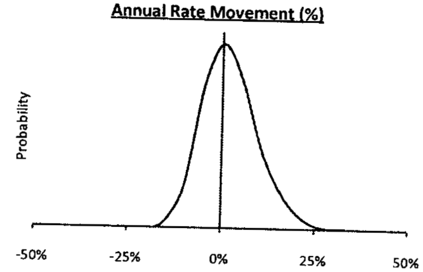

Supply Cost Surprise ($ / MWh)



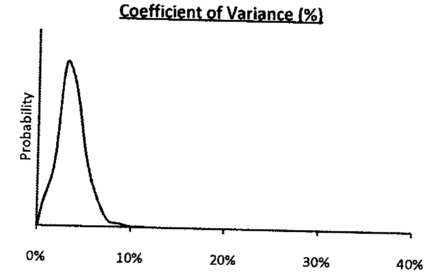

Deferral Account Balance ($MM)



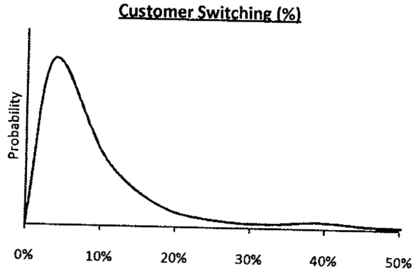

Annual Rate Movement (%)



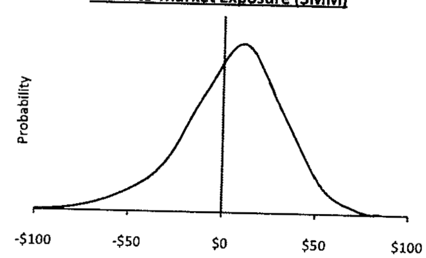

Coefficient of Variance (%)




Customer Switching (%)




Mark-to-Market Exposure ($MM)




Note: Metrics are based on 2014 results (i.e., enough time for the procurement cycle to reach equilibrium).

## METRICS — Expected Rate Level

- The expected rate level is the average load-weighted rate that an SOS customer would face in a year:

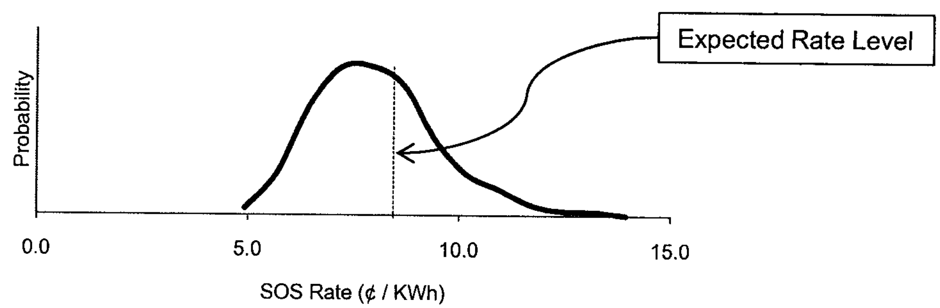
**Illustrative Standard Offer Service Rate Level**

| Delivery Month | Jan-14 | Feb-14 | Mar-14 | Apr-14 | May-14 | Jun-14 | Jul-14 | Aug-14 | Sep-14 | Oct-14 | Nov-14 | Dec-14 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| SOS Rate (¢ / KWh) | 7.74 | 8.04 | 7.94 | 8.65 | 7.81 | 8.09 | 7.96 | 8.37 | 9.96 | 10.40 | 9.36 | 8.85 |
| Total Eligible Load (MWh) | 371,833 | 327,861 | 340,913 | 288,822 | 293,588 | 385,558 | 480,899 | 412,442 | 333,331 | 305,243 | 323,969 | 365,015 |

| | |
|---|---|
| Load-Weighted SOS Rate (¢ / KWh) | **8.55** |

- Each scenario will yield a different rate; the mean across all scenarios is the expected rate level:

**Load-Weighted SOS Rates (¢ / KWh)**
**Illustrative**



# Supply Cost Surprise Calculation

➢ Supply cost surprise refers to the difference between ex ante known or forecasted SOS supply costs and the actual cost to serve:[1]

Illustrative Supply Cost 'Surprise' Calculation

| Month | Jan-14 | Feb-14 | Mar-14 | Apr-14 | May-14 | Jun-14 | Jul-14 | Aug-14 | Sep-14 | Oct-14 | Nov-14 | Dec-14 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Forecasted Supply Costs** | | | | | | | | | | | | |
| ATC Energy ($ / MWh) | $78.93 | $78.93 | $65.44 | $65.44 | $60.71 | $63.19 | $69.37 | $69.37 | $62.28 | $68.96 | $68.96 | $68.96 |
| Gross Up (%) | 4% | 11% | 7% | 6% | 4% | 9% | 10% | 11% | 10% | 9% | 7% | 8% |
| Shaped Energy ($ / MWh) | $81.69 | $87.21 | $70.02 | $69.03 | $62.83 | $68.88 | $76.30 | $77.00 | $68.20 | $74.82 | $73.78 | $74.13 |
| Capacity ($ / MWh) | $10.00 | $10.00 | $10.00 | $10.00 | $10.00 | $10.00 | $10.00 | $10.00 | $10.00 | $10.00 | $10.00 | $10.00 |
| Ancillary ($ / MWh) | $3.00 | $3.00 | $3.00 | $3.00 | $3.00 | $3.00 | $3.00 | $3.00 | $3.00 | $3.00 | $3.00 | $3.00 |
| RECs ($ / MWh) | $3.00 | $3.00 | $3.00 | $3.00 | $3.00 | $3.00 | $3.00 | $3.00 | $3.00 | $3.00 | $3.00 | $3.00 |
| Total Rate ($ / MWh) | $97.69 | $103.21 | $86.02 | $85.03 | $78.83 | $84.88 | $92.30 | $93.00 | $84.20 | $90.82 | $89.78 | $90.13 |
| Load (MWh) | 375,714 | 329,604 | 341,612 | 283,764 | 291,208 | 375,872 | 472,194 | 388,716 | 324,172 | 301,542 | 327,487 | 381,201 |
| Forecasted Supply Cost ($ / MWh) | $89.97 ($ / MWh) | | | | | | | | | | | |
| **Actual Supply Costs** | | | | | | | | | | | | |
| ATC Energy ($ / MWh) | $94.71 | $94.71 | $78.52 | $78.52 | $72.85 | $75.83 | $83.24 | $83.24 | $74.74 | $82.75 | $82.75 | $82.75 |
| Gross Up (%) | 4% | 12% | 8% | 6% | 4% | 10% | 11% | 12% | 10% | 9% | 8% | 8% |
| Shaped Energy ($ / MWh) | $98.36 | $105.65 | $84.57 | $83.27 | $75.65 | $83.33 | $92.39 | $93.31 | $82.55 | $90.48 | $89.12 | $89.57 |
| Capacity ($ / MWh) | $10.00 | $10.00 | $10.00 | $10.00 | $10.00 | $10.00 | $10.00 | $10.00 | $10.00 | $10.00 | $10.00 | $10.00 |
| Ancillary ($ / MWh) | $3.00 | $3.00 | $3.00 | $3.00 | $3.00 | $3.00 | $3.00 | $3.00 | $3.00 | $3.00 | $3.00 | $3.00 |
| RECs ($ / MWh) | $3.00 | $3.00 | $3.00 | $3.00 | $3.00 | $3.00 | $3.00 | $3.00 | $3.00 | $3.00 | $3.00 | $3.00 |
| Total Rate ($ / MWh) | $114.36 | $121.65 | $100.57 | $99.27 | $91.65 | $99.33 | $108.39 | $109.31 | $98.55 | $106.48 | $105.12 | $105.57 |
| Load (MWh) | 394,499 | 346,084 | 358,693 | 297,953 | 305,768 | 394,665 | 495,803 | 408,152 | 340,381 | 316,619 | 343,861 | 400,261 |
| Actual Supply Cost ($ / MWh) | $105.41 ($ / MWh) | | | | | | | | | | | |
| Supply Cost Surprise ($ / MWh) | $15.44 ($ / MWh) | | | | | | | | | | | |
| Supply Cost Surprise (%) | +17% (%) | | | | | | | | | | | |

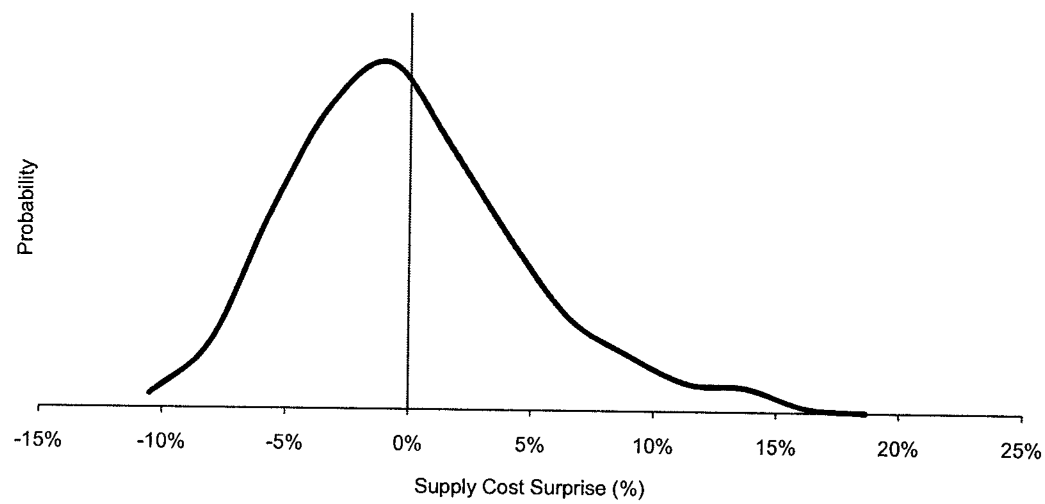
[1] Forecast is for a twelve-month period as of three months prior. While not shown, the supply cost surprise is calculated to ensure an expected surprise of zero.

Note: When the metric for supply cost surprise is expressed in terms of $MM, the calculation is performed by multiplying the $/MWh supply cost surprise by the actual SOS load.

## Supply Cost Surprise Risk

- In this case, the supply cost surprise was +17%. This means the cost per MWh of SOS supply was 17% greater than had been forecasted
- We perform this same calculation in each scenario and create a distribution of supply cost surprise:

**Distribution of Supply Cost Surprise**
**Illustrative**



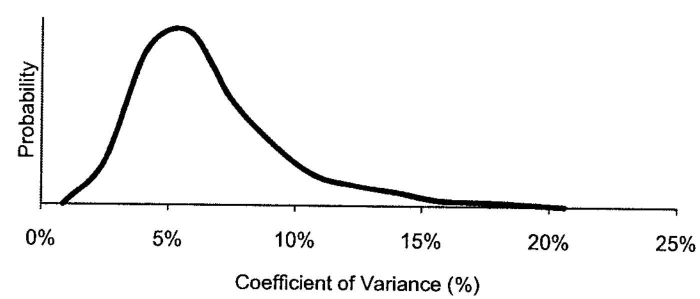
# Coefficient of Variance

- The coefficient of variance is a metric used by the New York PSC and relates to the volatility of the SOS rate measured on a monthly scale over the prior 12 months:

**Illustrative Coefficient of Variance Calculation**

| Delivery Month | Jan-14 | Feb-14 | Mar-14 | Apr-14 | May-14 | Jun-14 | Jul-14 | Aug-14 | Sep-14 | Oct-14 | Nov-14 | Dec-14 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| SOS Rate (¢ / KWh) | 7.74 | 8.04 | 7.94 | 8.65 | 7.81 | 8.09 | 7.96 | 8.37 | 9.96 | 10.40 | 9.36 | 8.85 |
| Standard Deviation of Rate (¢ / KWh) | 0.74 | | | | | | | | | | | |
| Average Rate Level (¢ / KWh) | 8.60 | | | | | | | | | | | |
| Coefficient of Variance (%) | **8.6%** | | | | | | | | | | | |

- This statistic is calculated in each scenario, allowing us to create a distribution of values:



# Annual Rate Movement

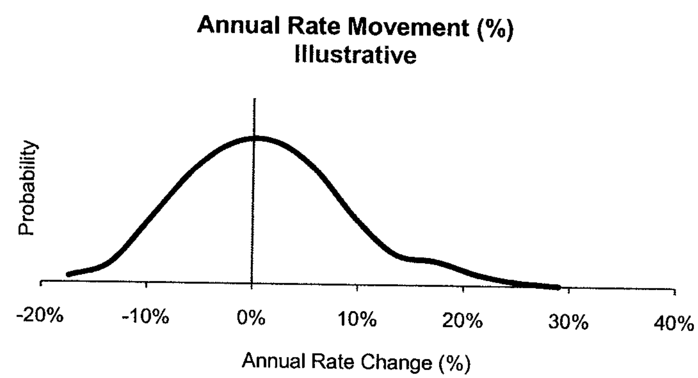
➢ A variant of the coefficient of variance involves looking at the volatility of year-over-year rate movements:

**Illustrative Annual Rate Movement Calculation**

| Scenario | 2013 Rate[1] | 2014 Rate[1] | Delta |
|---|---|---|---|
| 1 | $73.44 | $85.51 | 16.4% |
| 2 | $79.97 | $84.16 | 5.2% |
| 3 | $76.96 | $82.44 | 7.1% |
| 4 | $83.57 | $73.11 | -12.5% |
| 5 | $65.62 | $69.12 | 5.3% |
| 6 | $73.08 | $75.07 | 2.7% |
| 7 | $77.88 | $78.63 | 1.0% |
| 8 | $81.64 | $84.54 | 3.6% |
| ... | ... | ... | ... |
| 2,000 | $71.93 | $80.77 | 12.3% |

[1] Monthly SOS rate is weighted by total eligible load to determine the average rate a customer would face during the year.

➢ This statistic is calculated in each scenario, allowing us to create a distribution of values:



# Deferral Account Balance

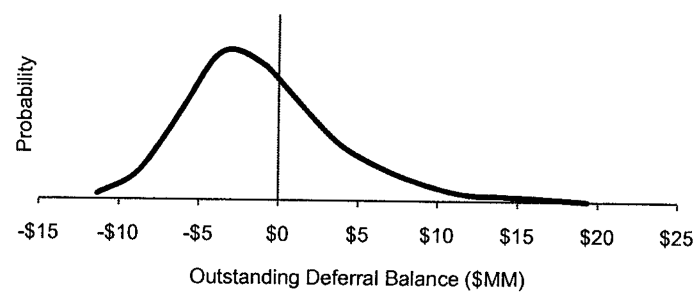
- The deferral account balance metric measures the size of the balance sheet item tracking the accumulated over/under level of cost recovery:

**Illustrative Deferral Balance Calculations**

| Month | Jan-14 | Feb-14 | Mar-14 | Apr-14 | May-14 | Jun-14 | Jul-14 | Aug-14 | Sep-14 | Oct-14 | Nov-14 | Dec-14 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| SOS Rate Revenues ($MM) | $30.0 | $30.0 | $30.0 | $30.0 | $30.0 | $30.0 | $30.0 | $30.0 | $30.0 | $30.0 | $30.0 | $30.0 |
| Deferral Rider ($MM) | | | -$0.4 | $0.1 | $1.7 | -$2.5 | $1.6 | $3.8 | -$0.4 | -$2.9 | $2.7 | $1.2 |
| Actual Costs ($MM) | $29.6 | $30.1 | $31.3 | $27.6 | $33.3 | $31.3 | $31.3 | $30.9 | $32.3 | $28.3 | $32.2 | $29.7 |
| Under / (Over) ($MM) | -$0.4 | $0.1 | $1.7 | -$2.5 | $1.6 | $3.8 | -$0.4 | -$2.9 | $2.7 | $1.2 | -$0.5 | -$1.5 |
| Interest ($MM) | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 | $0.0 |
| Deferral Balance ($MM) | -$0.4 | -$0.4 | $1.3 | -$1.1 | $0.5 | $4.3 | $3.9 | $1.1 | $3.8 | $5.0 | $4.5 | **$3.1** |

- This statistic is calculated in each scenario, allowing us to create a distribution of values

**Outstanding Deferral Balance EOY 2014 ($MM) Illustrative**




Note: Interest of 6% accrues on deferral balances.

# Mark-to-Market Exposure

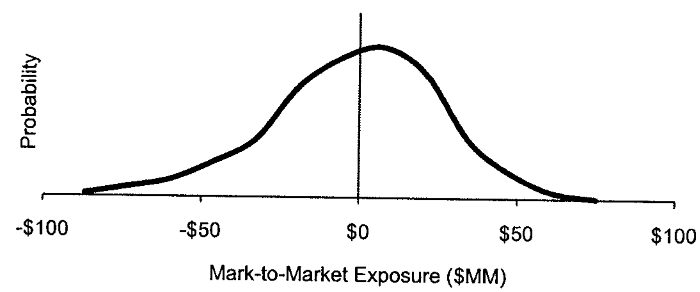
- Mark-to-market exposure indicates how far fixed-quantity commitments are out-of-market, and may be relevant for collateral requirements on block energy products:

**Illustrative Mark-to-Market Exposure[1]**

| Scenario | PV of Payments at Initial Mark | PV of Payments at Market Price | Potential Exposure |
|---|---|---|---|
| 1 | $11.0 | $10.4 | $0.6 |
| 2 | $9.8 | $9.9 | -$0.1 |
| 3 | $9.0 | $10.3 | -$1.3 |
| 4 | $8.8 | $9.4 | -$0.6 |
| 5 | $8.7 | $8.8 | $0.0 |
| 6 | $9.5 | $9.6 | -$0.2 |
| 7 | $9.5 | $8.2 | $1.3 |
| 8 | $8.6 | $11.0 | -$2.4 |
| ... | ... | ... | ... |
| 2,000 | $10.2 | $9.1 | $1.1 |

- This statistic is calculated in each scenario, allowing us to create a distribution of values:

**Potential Mark-to-Market Exposure ($MM)**
**Illustrative**




[1] Mark-to-market exposure can change over the course of the year. Therefore, this metric is calculated by identifying the month during which the average top decile exposure is greatest and then examining the mark-to-market exposure during that month. The calculation involves application of a discount rate of 10%.

A18

December 1, 2010

# Restructuring Key to Cheaper, Cleaner Electricity

By John Kelly



As the United States grapples with how best to address climate change and conservation—whether by taxing carbon, cap and trade, or setting higher renewable portfolio standards—an effective approach exists at the state level to reduce electricity producers' carbon emissions: restructuring.

How can opening competitive electricity markets help Americans reach their conservation and carbon reduction goals? The answer rests with Great Britain and those U.S. states that followed its lead.

According to the United Nations Framework Convention on Climate Change, Britain made nearly a 20% change in its greenhouse gas emissions between 1990 and 2007. After restructuring, high carbon‚Äiemitting coal plants were no longer protected as monopoly-owned stranded assets. Consumers and businesses were then free to choose their power from cleaner, more efficient power sources while competition-motivated plant operators improved efficiency and lowered costs.

So why are there so many critics of restructuring? First and foremost, California restructuring— based on a model that was abandoned by Britain—forced all generators and consumers into an hourly pricing pool, leading to market instability and gaming by generators. Britain learned through its early testing of the "pool-co" approach that it was essential to allow for bilateral contracts between generators and users; California failed to address these concerns.

Although restructuring may have failed in California, it is working in New England, Pennsylvania, Maryland, Texas, and Illinois. Recognizing the flaws in California's approach, these states implemented a bilateral restructuring model whereby the bulk of electricity is traded in direct contracts between generators and large distribution companies or customers. Hourly pricing markets in these regions provide a means for setting competitive market prices. These new markets also provide ancillary service payments to consumers for providing demand response, day-ahead, and other market services. In these new pricing markets, entrepreneurs and consumers are working together to lower demand when prices rise.

In restructured markets, consumers no longer foot the bill for new generation plant construction overruns. Most of us have not forgotten the billions in dollars consumers had to pay in the 1980s for huge nuclear plant construction cost overruns. In a restructured market, power plant overruns are borne by investors. When generators overbuild, investors foot the bill, not consumers.

Restructuring led to unintended benefits for consumers, saving two quadrillion British thermal units of energy annually—more than half of the total natural gas consumed by the U.S. commercial sector. New England and Texas generate a large portion of electricity from natural gas‚Äifired generators. Many of the new gas turbines, built because of restructuring, utilize about half the natural gas of the older, utility-built, simple-cycle gas-fired generators they displaced. Consumers in these restructured states also saved billions of dollars in fuel costs when natural gas prices increased dramatically (see the table).



**Estimates of selected restructuring benefits.**

| Benefit | Delta | Annual carbon reduction | Annual savings |
|---|---|---|---|
| New CCCT capacity displacing simple-cycle natural gas* | 149 GW of new CCCT capacity | ~125 million tons | ~2 quadrillion Btu ~$8 billion @$4/mmBtu |
| Increased nuclear production due to competition** | 230 million MWh of increased nuclear output | ~230 million tons | ~$12 billion |
| Lower nuclear O&M due to competition, 800 million MWh | $15/MWh reduced O&M cost | | ~$12 billion |
| Lower coal O&M due to competition, 1.9 billion MWh | $5/MWh reduced O&M cost | | ~$10 billion |
| Price/demand response | Later | Later | Later |
| Totals | | ~355 million tons | ~$42 billion |
| Impact | | 15% reduction in total electricity-related carbon emissions | Total reduction in costs for consumers of ~$10/MWh |

Notes:

umed 50% capacity factor ~~for all combined-cycle combustion tu~~ ... (CCCT) ... s an ... on ... s of ... /M ... or ~~displaced simple-cycle gas generation~~.

Also note that annual savings were much higher from 2001 to 2008 during the run-up in natural gas prices.

** Assumed carbon savings of 1 ton/MWh for displaced coal-fired generation. Please note that nuclear total capacity remained constant from 1990 at about 100 GW while output increased by 40% due to the threat of competition. The nuclear generation cost is about $15/MWh less than the coal generation displaced.



Sources:

1. Electric Utility Restructuring: A Guide to the Competitive Era, Peter Fox-Penner (1998).
2. Electricity Prices in a Competitive Market, www.eia.doe.gov/cneaf/electricity.
3. The Changing Structure of the Electric Power Industry, www.eia.doe.gov/cneaf/electricity (June 11, 1999).
4. Economic Analysis of Electricity Restructuring in Michigan, Standard & Poor's DRI (November 13, 1998).
5. Environmental Protection Agency EGrid database, eGRID2006 Version 2.1 Generator File Year 2004.
6. Department of Energy, Annual Energy Outlook 2009, Tables A9, A10 and A18. "The Change in Greenhouse-gas Emissions in Industrialized Countries," The Economist (October 30, 2009).

Another future benefit of restructuring is the displacement of coal generation and associated environmental impacts. In restructured states, as coal-fired generation costs increase due to carbon costs, cleaner, more efficient generation (e.g., wind and natural gas) pushes the higher-cost coal generation out of the market. Unfortunately, older, inefficient coal and gas plants in structured markets are deemed stranded assets. As carbon costs rise, vertically integrated utilities can pass carbon costs on to consumers as the "least cost option."

There have been missteps in restructured markets outside California, however; some generators gained market power in isolated markets, and residential retail markets have experienced problems. Independent system operators continue to adjust market rules and standards to address issues and improve competitive markets.

Restructuring is a new form of market regulation that treats consumers as partners, not prisoners. It is a market approach that provides state leaders and regulators a momentous opportunity to provide more reliable, affordable, efficient, and cleaner electricity to consumers and effectively curb climate change by reducing U.S. electricity's large carbon footprint.

—John Kelly is the deputy director of the Galvin Electricity Initiative. This commentary first appeared in *The Energy Daily*.

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A19

ANALYSIS GROUP
ECONOMIC, FINANCIAL and STRATEGY CONSULTANTS

# Allocating Investment Risk in Today's Uncertain Electric Industry: A Guide to Competition and Regulatory Policy During "Interesting Times"

**Susan Tierney**
**Analysis Group**

**Boston, Massachusetts**
**September 2009**

This White Paper was prepared for the Electric Power Supply Association. This paper represents the views of the author, and not necessarily the views of Analysis Group, EPSA, or its members.

# Allocating Investment Risk in Today's Uncertain Electric Industry: A Guide to Competition and Regulatory Policy During "Interesting Times"

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*Crisis: Danger and Opportunity*[1]

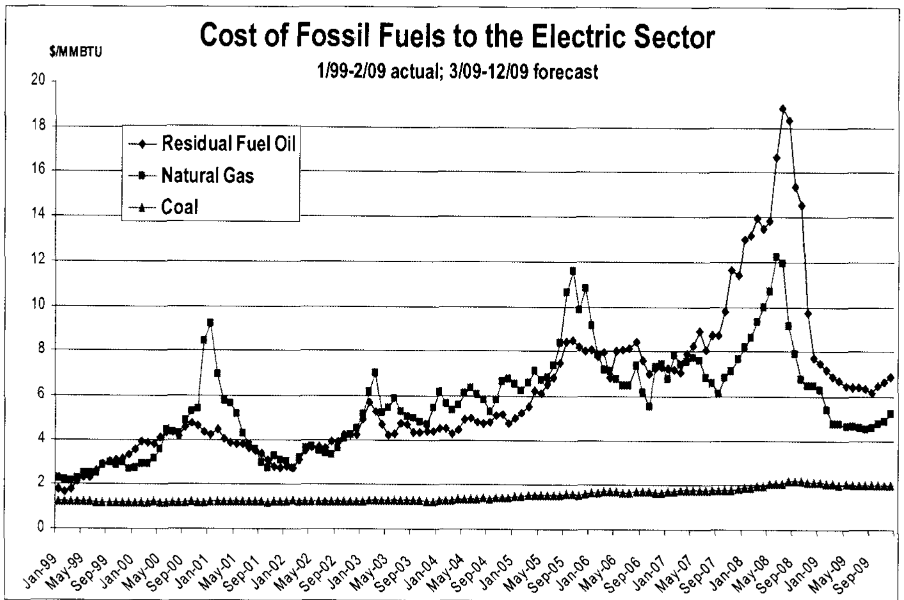
## Introduction

It doesn't take a crystal ball to know that this is a rough and uncertain time. While no one ever knows how the future will unfold, the severity of today's economic crisis lends a particularly sobering quality to these unknowns.[2]

In the electric industry, this uncertainty creates substantial challenges. This is a notoriously capital-intensive industry – whether the funding goes toward power plant investments, transmission or distribution facilities, large-scale adoption of metering equipment, or installation of large numbers of new solar panels on building rooftops. Capital is committed by many entities including competitive generators, utilities and others. Regardless of who provides it, capital requirements can be daunting.

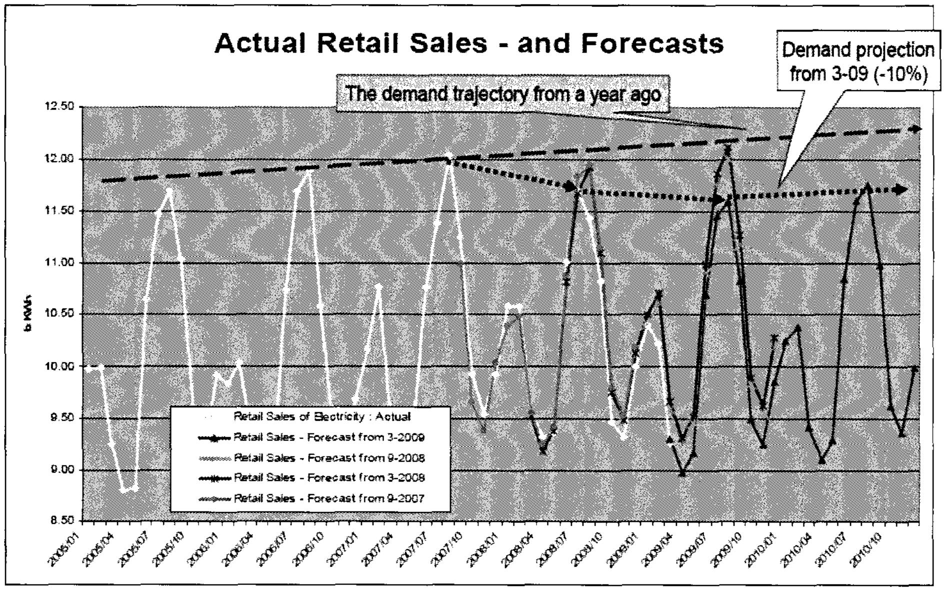
Knowing what type of investment to make is hard enough in more settled times. It is even harder given the various sources of uncertainty that abound at present:

- Will natural gas prices – and wholesale electricity prices in many regional markets – remain low, or rebound with global economic growth? (In the past year, the price of natural gas – which is used to produce one-fifth of the nation's power – rose to all-time highs as well as 5-year lows in the space of a few months.[3],[4])




Source: EIA[5]

- Will demand for electricity rebound after the current economic crisis begins to pass, or will the energy efficiency and demand-response measures promoted by the combined effects of the federal economic recovery program, state policy and programs of utilities and regional grid operators slow (or eliminate) increases in demand in upcoming years? (Forecasts of 2009 power use that were prepared in March 2009 show demand estimates 10 percent lower than forecasts prepared the year before.[6])




EIA, Electric Power Monthly data series; Short-Term Energy Outlook

- Will electric companies be able to fund new demand- or supply-side investments in light of balance sheet challenges,[7] current credit market conditions,[8] and traditional regulatory ratemaking policies[9] that need to adapt to today's realities?

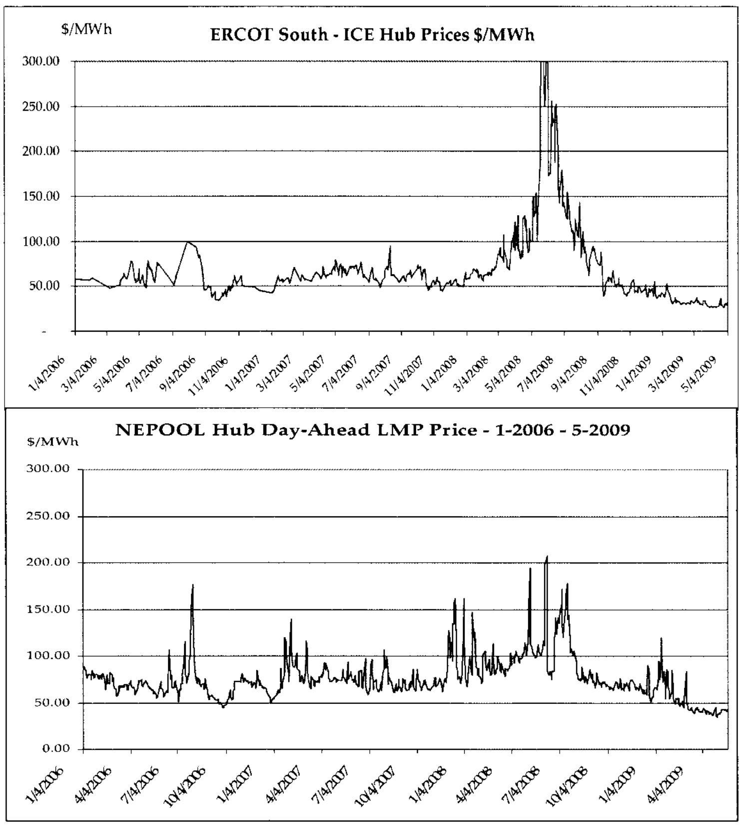
- What form will national carbon controls take by the time they impact the economy – given that their timing and shape are affected not only by congressional debates that are still underway[10] but also by countless implementation decisions that will need to be made over the years following passage of new legislation? Will its provisions create the right conditions to induce new low-carbon technologies into the market place?[11]

These are indeed "interesting times." As the Chinese say each time they use the word "crisis," this is both a challenging and opportune moment. President Obama referred to those challenges and opportunities when he spoke of the economy and the electric system on his inaugural day in January 2009,[12] and then again when he addressed a joint session of Congress a month later.[13] The American Recovery and Reinvestment Act is providing billions of dollars for investment in energy technologies. If the President accomplishes his goal, this will be a down payment towards larger changes in the electric industry, affecting demand for electricity, the robustness of the electric grid, and the ability of low-carbon and renewable technologies to move into markets.

These conditions pose a complicated set of options for electric companies and for regulators. How does one create an appropriate policy atmosphere in the face of so much risk and uncertainty?[*][14] An understandable response would be to retreat to the familiar. But what is safe ground in today's environment? I offer two suggestions for how regulators might approach these issues: First, ride the horse you're on (or, as Abraham Lincoln would say, don't change horses midstream). Second, extract the best from principles of competition and regulation.

## Ride the horse you're on

In recent years, there have been debates in policy circles and in the industry more generally on whether those parts of the country that restructured their electric industry would be better off returning to a more traditional industry model. Although political pressure (especially among elected officials) to do so has ebbed somewhat with the decline in natural gas prices and the related drop in wholesale electricity prices, there are still rumblings in various corners about this issue. (See figures to the right, which illustrate the variation in electricity prices over the past several years, using Texas (ERCOT South) and New England (NEPOOL) as examples.)




Source: EIA, Wholesale Market Data, http://www.eia.doe.gov/cneaf/electricity/wholesale/wholesale.html, accessed on June 5, 2009.

[*] In a separate document ("Appendix Figures for the Allocating Investment Risk in Today's Uncertain Electric Industry: A Guide to Competition and Regulatory Policy During "Interesting Times" (September 2009), I have compiled information that compares historical forecasts of important variables (like demand, fuel prices, construction costs, and so forth) that affect investment decisions, with information about the actual trends in the variables of interest over time. Please see the EPSA website to review this separate appendix.

At this particularly turbulent time in our industry, it is more important than ever to do things to raise investor confidence in ways that will produce benefits to consumers. In this context, it is not helpful to keep debating the "markets versus regulation" question. All else equal, regulatory uncertainty and political risk will always put pressure on investor confidence. There is already enough uncertainty for all of us to deal with,[15] without adding to it by continuing to debate whether a state should dramatically alter the structure of its electric industry. That is why I suggest that each jurisdiction "ride the horse you're on" and then make good use of the policy tools of competition and regulation in order to provide the best sustainable, long-term outcomes to reliably serve consumers.

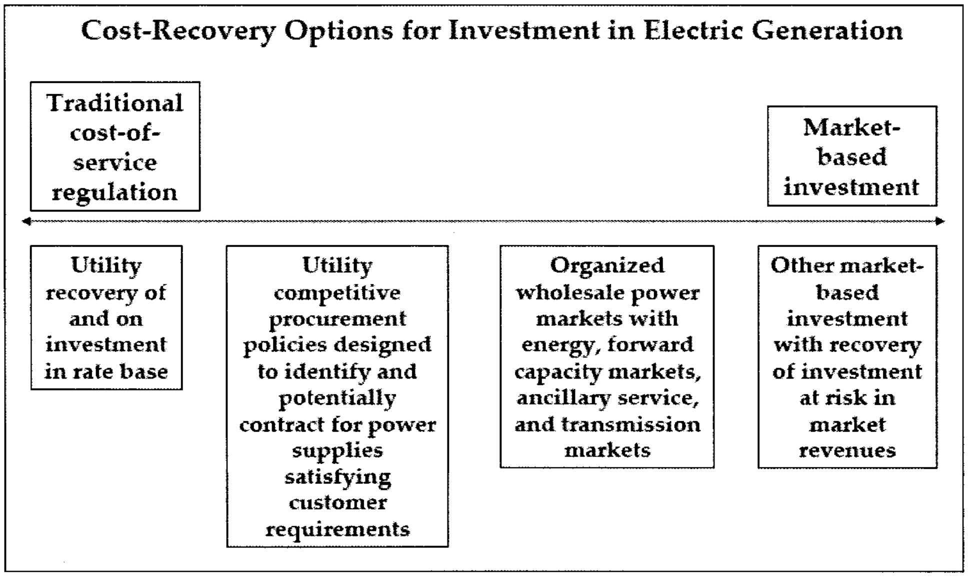
**Extracting the best from competition and regulation**

For many decades, the electric industry relied principally on traditional cost-of-service regulation. More recently, the industry has also incorporated a number of regulatory approaches built on competition. Many years of experience provide instructive lessons about why it is important to rely on the best of both market and regulatory mechanisms.

We know that it is important to structure both markets and regulation using sound policy design. On the traditional ratemaking side, we learned lessons from problems caused by after-the-fact prudency reviews of massive nuclear investments in the 1980s, and we are learning to align incentives with desired results as we move toward reliance on revenue decoupling as a companion to energy efficiency initiatives by utilities.[16] And in markets, we better understand the importance of market design after the California electricity crisis in 2000-2001, and as we see the benefits of competition for improved power plant performance,[17] and in the results of competitive power procurements.[18]

Continuing on a regulatory path that attempts to assign risks to those parties best suited to best manage them is a sound rock to stand on. This is hardly rocket science, but it is still worth remembering that this will give electricity customers the benefit of the best of both market-based approaches and regulation.

There are many examples of well-functioning market designs in the space between a pure traditional cost-of-service regulatory framework and a pure merchant model for generation investment. While there are various designs along the spectrum, there are two strong, well-functioning approaches in the middle: energy auctions administered by regional transmission organizations, and competitive solicitations carried out by load-serving entities such as electric utilities. Both operate pursuant to rules established by regulators. And both rely on competitive pressures on suppliers to discipline costs, and the oversight of regulators to ensure fair and open competition. In the following section, I review the two bookends and the two "middle" approaches.




### These Four Cost-Recovery Options

The starting point for discussing these investment recovery options is to remember the importance of establishing appropriate regulatory incentives for disciplining costs. In well-performing markets, firms and individuals have incentives to reduce costs and make appropriate investments because they can realize the consequences of their decisions.

In the electric industry historically, regulation arose because various conditions[19] prevented reliance on market forces. Regulated cost-based rates serve as a second-best proxy for price in the absence of competitive markets.[20] In the presence of markets, we can shop around for what we consider to be the best deal, knowing that suppliers are competing with each other for our business.

Thus, the electric industry has two archetypal models for inducing power generation investments. On the one hand are power plant investments and operations under traditional cost-based, rate-of-return regulation of utilities; on the other hand, investments and operations of power plants occur under market-based rates. These are not the sole models for investment, but rather serve as "bookends" for other possible arrangements between investors, utilities, regulators, and third-party suppliers. In practice, many utilities use competitive markets as part of how they approach investments and operations under regulated rates.[21] And many third-party suppliers rely on contracts with regulated utilities as a fundamental element of the suppliers' ability to bring market-based products to fruition.[22]

Still, focusing on utility rate-base investment and merchant third-party market-based investment as two ends of the spectrum (shown in the figure above) allows us to examine important issues about how these alternative arrangements allocate the risks between the investor, the utility, the regulator, and the consumer. The different regulatory/ financial incentives involve the following elements:

- *Recovery of and on investment subject to regulatory approval*. Under this classic model, the utility undertakes an investment and construction program (with more or less regulatory review of its resource plans). As the project becomes ready to provide service to consumers, the utility seeks to include the new investment in rate base – and to charge customers rates that allow recovery of and on the investment. The regulators then perform an after-the-fact review of the prudency of the investment, and determine whether it is "used and useful." Having been approved by utility regulators, such new investment is folded into the utility's revenue requirement at the next rate case, and rates are set to recover these new costs (along with other costs in the new period).[23],[24]

- *Utility's Power Purchase Agreement with an Independent Supplier*. Instead of building its own power plant, a utility may contract for wholesale power supply from independent suppliers through a long-term agreement. Such agreements may arise from bilateral negotiations or competitive procurements. Many formal competitive procurements are subject to oversight and rules of regulators. By design, competitive procurements for incremental resources are intended to be the means by which a utility identifies the "best" resource option to satisfy a particular supply need (e.g., dispatchable intermediate supply, or peaking capacity, or renewable energy credits).[25] If the utility selects a third-party supply offer (as opposed to building its own plant), a contract between the utility and the supplier serves as the basis for allocating specific risks between the investor (the power supplier) and the utility (who buys the power). Typically, the costs associated with contracted-for supplies are recoverable in rates, often through a mechanism that passes costs through to consumers (as in a fuel-adjustment clause or similar cost-recovery mechanism). (Note that another form of competitive procurement exists in states with restructured electric industries with distribution companies without their own power supply; here, the utility may rely on competitive procurements to procure wholesale supply for basic service customers.)

- *Investment within Organized Wholesale Power Markets*. Some companies have been able to support investment in generation through their participation in various auctions in power markets administered by Regional Transmission Organizations ("RTOs"). Although the specific details of RTO-administered markets vary across regions, some (e.g., PJM, ISO-NE) involve a combination of markets (e.g., day-ahead and real-time energy markets, forward capacity markets, various ancillary service markets, transmission congestion contracts) that support plant investments. Some take the form of a financially binding long-term agreement (such as a multi-year transmission congestion contract, or a three-year forward capacity contract entered into as a result of a capacity auction), while others are structured in the way of short-term performance-based auctions (e.g., a financially binding day-ahead hourly energy auction).

- <u>*Merchant Plant Development.*</u> Under a pure merchant model, a third party (including in some cases a utility's unregulated affiliate) makes an investment in new generation facilities outside of a regulated cost-recovery framework. These investments are undertaken without the expectation of revenues obtained through regulated rates – whether through the utility's regulated ratebase, or through a contract that relies on recovery from a utility's customers, or through the regulated tariff of a regional transmission organizations). These investments may rely, however, on financial support or contractual commitments from unregulated retail providers,[26] or on the strength of the developer's/investor's balance sheet.

## Allocating Risk – How It Works Under the Different Cost-Recovery Options

These various approaches involve different arrangements under which investment risk is borne by consumers.

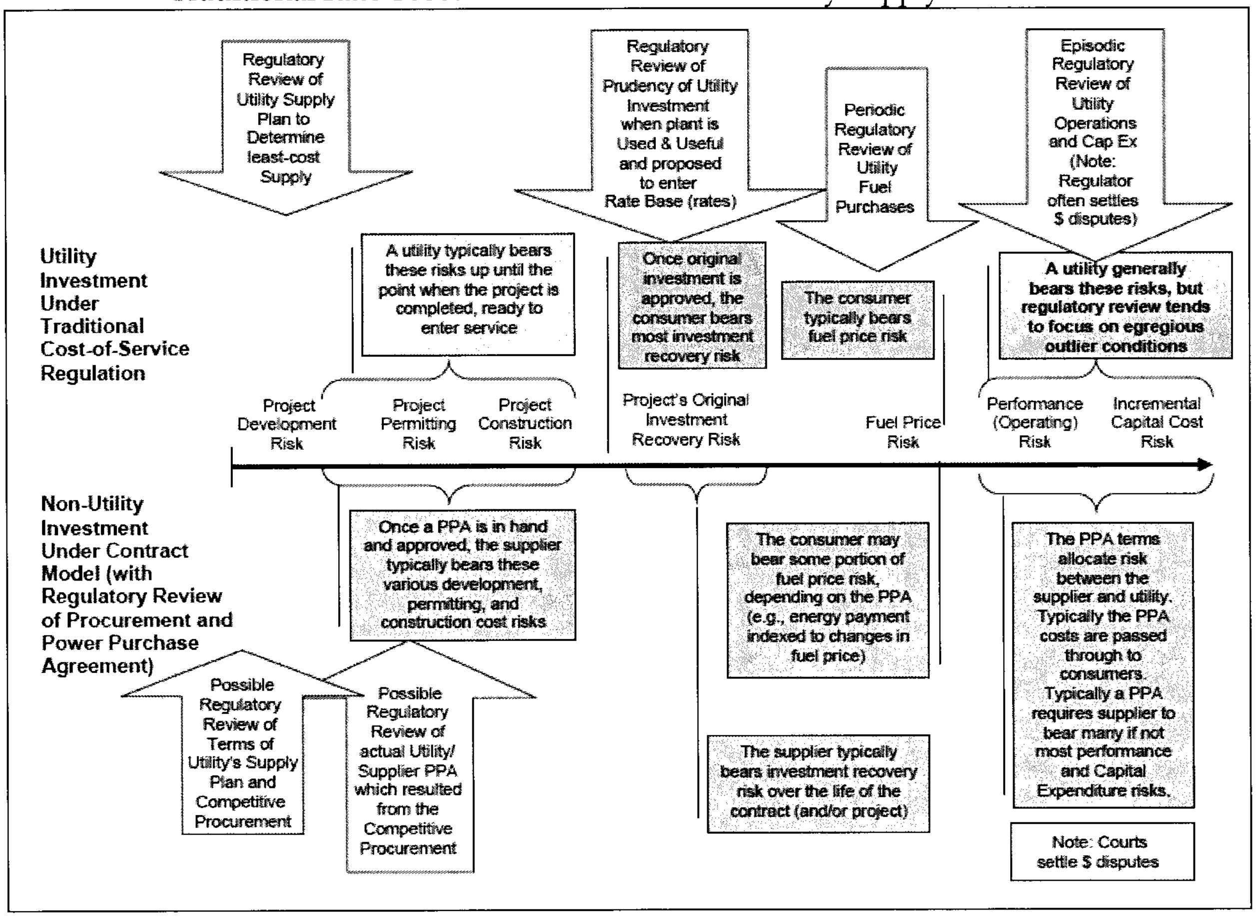
For example, after-the-fact review of utility power plant investments typically involves having the utility bear certain investment risks during the course of the planning, development and construction process. In the classic form of "prudency" reviews, the regulator assesses the utility's conduct after the fact, and uses adjudicatory proceedings to determine the extent to which appropriate and effective efforts were made by the utility to prudently manage such costs up to the point when the plant is ready to enter commercial operation and the utility seeks to recover investment costs in rates. While there are notorious examples of investment disallowances during the nuclear era, more commonly state and federal utility regulators have allowed utility investment into rates once it is used and useful.[27]

By contrast, a utility contract with a competitive supplier typically fixes the terms of payments and requires the supplier to bear many project risks, including development, permitting, construction-cost, and operating risk. Such agreements may allow certain elements of supplier compensation to vary over the life of the delivery of services under the contract, such as when construction payments are pegged to price indices that affect construction materials, or where energy prices are pegged to fuel price indices. Either way, because such contractual terms allow the third party supplier to retain profits from the reduction of costs, it typically provides an incentive to undertake efforts to lower these costs, and the supplier's original price was determined through a competitive process that yielded the lowest cost or best value to consumers. A performance-based contract can also insulate consumers from various risks associated with cost overruns and performance problems that might arise over construction and/or operations of the plant.

In both of these different approaches (e.g., rate basing of utility investment in plant, versus power purchase agreements between the utility and a supplier), regulators maintain oversight of any costs that may be recovered from ratepayers. Traditional cost-of-service review provides regulators with an on-going role in determining how the costs associated with the facility's construction and operation are passed through to consumers in rates, with difficult choices on whether to allow recovery of cost overruns by the utility when they occur.[28] Investment risk is usually settled at the time the utility presents the investment to regulators for approval to go into rates; regulatory treatment of operating costs, fuel cost and incremental capital expenditures for the facility may occur over the life of the unit. By contrast, utility purchase power agreements with suppliers attempt to fix the terms of payment in advance (e.g., prior to the delivery of third-party supply or the utility's investment); the regulatory review occurs at the time the utility presents the contract to the regulators for approval. This approach shifts substantial construction, fuel and operational risk away from consumers and therefore can provide important benefits to consumers given the many types of uncertainties facing the industry described earlier. Use of power purchase agreements does, however, involve some degree of mutual commitment on the part of regulators and utilities to live by the terms of potentially long-term agreements reached at the outset of a new investment. To be effective, the investor's commitment to bear the risks associated with project development must be matched by a corresponding commitment by the regulator to abide by the agreement regardless of external market outcomes – just as the third-party supplier is bound to the terms of any contract, for better or worse. Absent such regulatory commitment, the risk premiums required by investors to compensate for this regulatory risk may well offset the potential ratepayer gains from shifting project risks onto suppliers.

The choices among the alternative agreement structures involve important questions for regulators over the assignment of costs arising from particular infrastructure investments, and their ability to impose cost-discipline on and engage in risk sharing with utilities and third-party power suppliers. This is illustrated in the figure, below, which identifies and compares various risks for a traditional rate-based investment and an agreement for incremental supply from a 3rd-party supplier. These risks include a project's development, permitting and construction-cost risk; regulatory risk; risk of recovery of original investment; fuel price risk; plant performance (operating) risk; and incremental capital additions risk.

Comparison of Various Power Plant Investment and Operating Risks for a Traditional Rate-Based Investment and Third-Party Supply Contract




In practice, the appropriate cost-recovery and risk-allocation arrangements for a given resource and a given utility depends on many factors. Depending on the nature of the capital, operating and technology risks associated with a desired resource and the utility's existing portfolio of physical and financial assets, certain assignment of economic and financial risk may be more advantageous than others. There might be situations, for example, in which regulators determine that the presence of some type of profound risk and uncertainty would chill market participation in the absence of regulatory or other public policy decisions assigning to consumers the responsibility to bear some of this risk. This could occur for investment in certain advanced, capital-intensive, low-carbon technologies (such as a coal-fired integrated gasification combined cycle with or without carbon sequestration systems) which may involve technology, construction and operating risks that third-party suppliers are unwilling to undertake (or willing to undertake only at a price unacceptable to regulators). In such a case, the policy maker – whether a legislature or a regulator – might decide that it is important to include some mechanism by which consumers bear some of this risk.[29] This could take the form of a market-based approach for procuring renewables (or renewable energy credits), with regulators determining the amount to purchase and the market determining the lowest-cost means to accomplish it. Thus, the variety of agreements structures depicted in the figures above provides regulators with significant flexibility in how they encourage needed infrastructure investments.

It is important for regulators to recognize, however, that risk-sharing can be achieved through arrangements between consumers and third-party suppliers, as well as the more traditional risk-sharing between consumers and utilities. For example, if regulators determined that consumers should bear certain technology risk, then the option to supply resources with that attribute and risk profile could be made available equally to the utility and to third parties.

Similarly, it may be useful for regulators to avoid prescribing certain types of agreement structures, so that third party suppliers can compete for the opportunity to supply and offer alternative agreement structures that they believe can provide the utility and its customers with the best value. Thus, properly structured and independently evaluated competitive procurements provide a constructive means to determine prudent resource outcomes for consumers. Competitive processes provide an important mechanism that allows the market to make offers with different risk sharing arrangements while still providing regulators with continued oversight of resource needs and decisions.

### Closing observations

This focus on incentives is a reminder of the importance of market forces in disciplining costs. Increases in output and performance by generating facilities whose operation has shifted from regulated to competitive markets attest to the potential of market forces to lower costs in the electricity industry. This is not to say that markets operate perfectly – something that the current capital market crisis makes abundantly clear. They need attentive oversight and regulation to assure that they are functioning well. But well-functioning competitive processes provide valuable attributes – choice, innovation, cost discipline, service quality, and so forth – which together provide benefits to consumers regardless of the overall regulatory structure of a particular jurisdiction. It is using these competitive mechanisms in conjunction with strong regulatory oversight that I believe is the best path forward in these uncertain and "interesting" times.

## End Notes[30]

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[1] Apologies to Victor Mair, of the University of Pennsylvania, who explains that the Mandarin character for "crisis" is not intended to be the same as "danger + opportunity" even though "crisis" is composed of two characters whose separate meanings are "danger" and "opportunity." http://www.pinyin.info/chinese/crisis.html.

[2] See N. Gregory Mankiw, "Economic View: That Freshman Course Won't Be Quite The Same," *The New York Times*, May 24, 2009. As Mankiw explains, "the teaching of basic economics will need to change in some subtle ways in response to recent events," including "the challenge of forecasting. It is fair to say that this crisis caught most economists flat-footed. In the eyes of some people, this forecasting failure is an indictment of the profession. But that is the wrong interpretation. In one way, the current downturn is typical: Most economic slumps take us by surprise. Fluctuations in economic activity are largely unpredictable." www.nytimes.com/2009/05/24/business/economy/24view.html?ref=todayspaper, accessed May 24, 2009.

[3] High prices of $10.82 per mcf (in June 2008) and $10.62 per mcf (in July 2008) exceeded the prior record-breaking prices in the months following Hurricanes Katrina and Rita ($10.33/mcf in September 2008, and $9.89/mcf in October 2008). Prices in November 2008 ($5.97/mcf), December 2008 ($5.87/mcf) and January 2009 ($5.15/mcf) were the lowest same-month prices since 2003. EIA Monthly wellhead price of natural gas, 1-1-00 through 1-1-09, in $ per mcf.

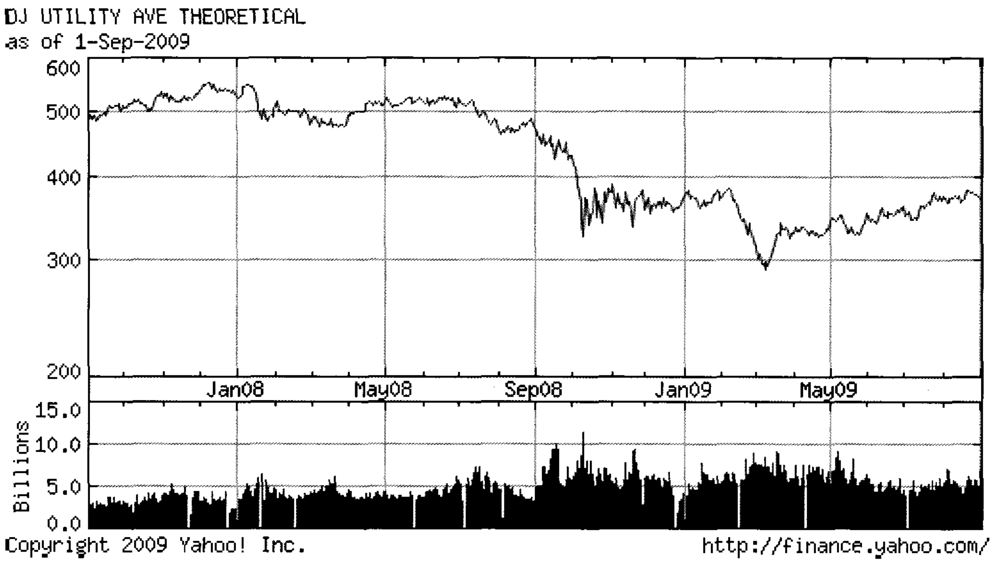
[4] Also, last year's estimate of the average price of natural gas in 2009 was more than double the estimate made a year later. For example, the estimate for the average price of natural gas to the electric sector was $9.15 per MMBtu (as estimated in May 2008) and $4.30 per MMBtu (as estimated in May 2009). EIA, Short-Term Energy Outlooks, Table 7.a.

[5] EIA, Short Term Energy Outlook Data Tables, http://www.eia.doe.gov/emeu/steo/pub/xls/STEO_m.xls (March 2009)

[6] The forecasts of electricity use in 2009 that were prepared during the Spring of 2009 show projections 10 percent lower than forecasts prepared as recently as a year before. In the figure, the forecast for 2009 prepared as of 3-2009 (shown in red) is 11-12 percent lower than the forecast for 2009 prepared one year previously (shown in blue). During the year ending 3/2009, retail sales were 2 percent lower than during the year ending 3/2008, and 5 percent lower than during the year ending 3/2006. See EIA, Monthly Electric Sales, from April of one year to the end of March of the following year (i.e., April 2000 through March 2008, and April 2008 through March 2009).

Further, in its most recent assessment for the summer months of 2009, the North American Electric Reliability Corporation ("NERC") made the following observations: "Decreased economic activity across North America is primarily responsible for a significant drop in peak-demand forecasts for the 2009 summer season.... Compared to last year's demand forecast, a North American-wide reduction of nearly 15 GW (1.8 percent) is projected. In addition, summer energy use is projected to decline by over 30 Terawatt hours (TWh), trending towards 2006 summer levels. While year-over-year reduction in electricity use is not uncommon — industrial use of electricity has declined in 10 of the past 60 years [fn in original], for example — it is critical that infrastructure development continues despite this decline. Based on the information provided as part of this assessment, most Regions have not yet experienced adverse impacts on infrastructure projects. However, WECC has indicated that some generation and transmission projects have been deferred or cancelled, in part due to overall economic factors…." (NERC, Summer Assessment 2009, pages 1-3.)

[7] During one week alone in the Fall of 2008, electric industry securities lost a third of their value. The Dow Jones Utility Average index fell from 486.14 on August 28, 2008, to 324.57 on October 10, 2008, a decline of 34 percent in the overall market capitalization of the electric companies tracked by this index. (During this same period, the Standard & Poor's 500 Index fell more than 30 percent – from 1,300.68 to 899.22 between August 28 and October 10.) The changes happened against a 12 month high of 552.74 in December 10 2007. Prices declined again in March 2009 to a low of 296.89,, but have rebounded somewhat since then. The index had a value of 367.26 on September 2, 2009. http://finance.yahoo.com/q?s=%5EDJU




[8] Capital markets are quite constrained due to the financial crisis facing the country. There are fewer financing options available and accessing capital has become more expensive. Utility companies' credit ratings are dropping, with a higher percentage of downgrades to upgrades in the past year. (See, for example, S. Bonelli, Fitch Ratings, presentation to the Energy Bar Association, April 23, 2009.) In addition, tight credit markets have been significantly tougher for companies with poorer credit ratings. While widening credit spreads (e.g., the difference between bond yields and yields for 10-year treasury notes) have been particularly dramatic for bonds issued by companies with poorer credit ratings, they have been significant for all companies regardless of their credit-worthiness.

[9] Examples of utility regulatory policies that are undergoing change include:

- Adoption of revenue decoupling for utilities whose revenues are affected by the adoption of cost-effective energy efficiency ("EE") measures. ("[E]ncouraging or mandating demand-side EE schemes without shielding the electric utility sector from financial harm is becoming an increasingly important credit issue due to the potential for decreased sales revenues and recovery or authorized costs. Historically, traditional rate design generally resulted in higher utility profits when energy sales increased, and lower utility profits when sale dropped. Amid the current recession and the significant increase in federal spending on EE, we believe that utility sector credit quality may benefit from regulatory and public policy that addressed concerns over cost under recovery. Provisions like decoupling mechanisms may untie or lessen the correlation between a utility's profits and energy sales, mitigating potential utility financial risks." Tony Bettinelli, "When Energy Efficiency Means Lower Electric Bills, How Do Utilities Cope?" Standard & Poor's RatingsDirect, March 9, 2009. )

- Use of competitive procurement approaches for arranging supply for retail electricity customers. (See Susan Tierney and Todd Schatzki, "Competitive Procurement of Retail Electricity Supply: Recent Trends in State Policies and Utility Practices," prepared for the National Association of Regulatory Utility Commissioners (NARUC), July 2008.)
- Use of long-term contracts and renewable portfolio standards to support investment in renewable energy generating facilities. (See: New York Independent System Operator, response to Question 15, http://www.nyiso.com/public/webdocs/newsroom/whats_new/ResponsetoBrodskyCahillCompleteDocument.pdf.)
- Reliance on various capital-expenditure adjustment mechanisms and reliance of future test years (See Edison Electric Institute's 2008 Financial Review (Plus 2009 Developments), Annual Report of the U.S. Shareholder-Owned Electric Utility Industry," http://www.eei.org/whatwedo/DataAnalysis/IndusFinanAnalysis/Documents/Financial_Review_full.pdf.)
- Adoption of forward capacity markets in Regional Transmission Organizations (see, for example, http://www.epsa.org/forms/uploadFiles/FE8800000177.filename.FYI-4_Policy_ Paper -_Essential_Elements_Final.pdf)

These are but a few of the approaches that are in discussion – and in use in many parts of the country.

[10] As of this writing, the House has approved H.R. 2454, "The American Clean Energy and Security Act." As described on the Committee's website, "This legislation is a comprehensive approach to America's energy policy that charts a new course towards a clean energy economy." The House bill differs in many respects from parallel bills currently introduced in the Senate.

[11] There are debates in the literature about whether a new carbon cap-and-trade program that is able to make it through Congress in the near term will produce greenhouse gas allowance prices high enough to induce investment in advanced technologies (e.g., advanced coal-fired generation with carbon capture and sequestration) that are capital intensive, emit low greenhouse gases and still not fully commercial viable. See, for example, National Commission on Energy Policy, "Ending the Energy Stalemate: A Bipartisan Strategy to Meet America's Energy Challenges," December 2004, http://www.energycommission.org/ht/a/GetDocumentAction/i/1088; Constantine Samaras, Jay Apt, Ines L. Azevedo, Lester B. Lave, M. Granger Morgan, and Edward S. Rubin, "Cap and Trade is Not Enough: Improving U.S. Climate Policy," March 2009. http://www.epp.cmu.edu/httpdocs/ Publications/ClimatePolicy.pdf.

[12] Speaking of the entire country's situation during his Inaugural address in January 2009, President Obama said, "That we are in the midst of crisis is now well understood.... Our economy is badly weakened, ...and each day brings further evidence that the ways we use energy strengthen our adversaries and threaten our planet....The state of the economy calls for action, bold and swift, and we will act — not only to create new jobs, but to lay a new foundation for growth. We will build the roads and bridges, the electric grids and digital lines that feed our commerce and bind us together. ... We will harness the sun and the winds and the soil to fuel our cars and run our factories. ... All

this we can do. All this we will do." Text of President Barack Obama's inaugural address on Tuesday, as delivered, *by The Associated Press* The Associated Press Tue Jan 20, 5:04 pm ET.

[13] "We know the country that harnesses the power of clean, renewable energy will lead the 21st century. And yet, it is China that has launched the largest effort in history to make their economy energy efficient. We invented solar technology, but we've fallen behind countries like Germany and Japan in producing it. New plug-in hybrids roll off our assembly lines, but they will run on batteries made in Korea. ... It is time for America to lead again. Thanks to our recovery plan, we will double this nation's supply of renewable energy in the next three years. ... We will soon lay down thousands of miles of power lines that can carry new energy to cities and towns across this country. And we will put Americans to work making our homes and buildings more efficient so that we can save billions of dollars on our energy bills. But to truly transform our economy, protect our security, and save our planet from the ravages of climate change, we need to ultimately make clean, renewable energy the profitable kind of energy. So I ask this Congress to send me legislation that places a market-based cap on carbon pollution and drives the production of more renewable energy in America. ..." Remarks of President Barack Obama – As Prepared for Delivery - Address to Joint Session of Congress, Tuesday, February 24th, 2009. http://www.whitehouse.gov/the_press_office/remarks-of-president-barack-obama-address-to-joint-session-of-congress/.

[14] On February 17, 2009, President Obama signed into law H.R. 1, the American Recovery and Reinvestment Act of 2009 (the "Act").

[15] To underscore the array of uncertainties and forecasting challenges that affect decision-making in the industry, here is a list of several of the variables that routinely make investment decisions quite difficult:

- demand forecasting, given different economic outlooks and assumptions about both the penetration of electricity-using equipment and the effects of energy efficiency measures;
- fuel price forecasting, especially for fossil fuels;
- estimation of capital costs of different technologies, including not only large central-station generating plants (such as nuclear, advanced coal, centralized solar facilities) as well as renewable energy and distributed generating units (e.g., off-shore wind, roof-top solar);
- projecting performance characteristics (e.g., heat rates, construction costs, environmental emissions, availability of manufacturers' guarantees) of advanced technologies not yet ready for commercialization;
- forecasting the effect of regulatory and policy change, especially relating to environmental requirements and non-traditional cost-recovery ratemaking mechanisms;
- future price of emissions allowances;
- on-peak reliability value and potential capacity factors of various technologies (e.g., advanced nuclear, wind, solar, coal with carbon capture and sequestration); and
- siting attitudes towards particular facilities (e.g., nuclear projects, coal plants, wind farms, transmission facilities, carbon sequestration projects).

Additionally, in today's credit markets, there is the added risk of highly constrained access to and cost of capital. Many of these variables are discussed in more detail in the companion appendix document to this white paper ("Appendix Figures for the White Paper: Allocating Investment Risk in Today's Uncertain Electric Industry: A Guide to Competition and Regulatory Policy During 'Interesting Times,'" September 2009), which can be found on the EPSA website.

[16] "The desire of reward is one of the strongest incentives of human conduct; ...the best security for the fidelity of mankind is to make their interest coincide with their duty." Alexander Hamilton, The Federalist Papers (essay series), 72, 21 March 1788.

[17] For example, *see* Matthew Barmack, Edward Kahn and Susan Tierney, "A Cost-benefit Assessment of Wholesale Electricity Restructuring and Competition in New England," *Journal of Regulatory Economics*, May 12, 2006; Kira Fabrizio, Nancy Rose and Catherine Wolfram, "Do Markets Reduce Costs? Assessing the Impact of Regulatory Restructuring on U.S. Electric Generation Efficiency," *American Economic Review*, Volume 97, No. 4, September 2007. See also, http://www.nyiso.com/public/webdocs/newsroom/press_releases/2009/Power_Plant_Efficiency_Improved_with_Competition_04202009.pdf.

[18] See Susan Tierney and Todd Schatzki, "Competitive Procurement of Retail Electricity Supply: Recent Trends in State Policies and Utility Practices," prepared for the National Association of Regulatory Utility Commissioners (NARUC), July 2008.

[19] These historical "natural monopoly" conditions included economies of scale in distribution systems, where it was inefficient for multiple firms to install and operate parallel power lines on city streets and in large urban systems. As a consequence, monopoly firms could provide service more efficiently that a competitive market. In such a situation, regulation was viewed as essential to curb a monopoly's natural inclination to abuse its market power. Over the last quarter of the 20th century, economic and technological changes in the generation portion of the electric industry eroded the natural monopoly conditions in the generation portion of the market.

[20] In the absence of markets – as occurs with regulated monopolies – the rate established by regulators serves as a proxy for price, with regulated rates serving to create prices that, to the extent possible, reflect those that would arise from a competitive market.

[21] Some utilities make investments under "performance-based rates," which provides certain incentives for utilities to reduce cost. Even in most jurisdictions with performance-based rates, however, regulators and utilities still tend to rely on a model that places prudent, used and useful investment in rate base with the prospects of recovery of and on that investment through regulated rates. And even where utilities are entering into power plant investments for which they seek to receive traditional cost recovery (e.g., through inclusion of prudently incurred investment in rate base and through recovery of expenses associated with operating power plants in cost-based rates), they may use various markets and binding contracts with third parties to provide goods and services they need to provide service to consumers. When viewed most broadly, such competitively solicited contracts may include agreements with equipment suppliers or construction contractors, fuel supply agreements, and so forth.

[22] For example, many independent power producers have relied upon the existence of a power purchase agreement signed with a utility as a critical element of the package provided to prospective lenders to demonstrate the financial viability of their projects and to qualify for debt financing. The lenders have tended to view such contracts as lowering project risk, especially in light of a body of utility and contract law, utility regulation and court decisions that has substantially allowed for the recovery of the costs associated with such 3rd-party supply contracts by the utility in rates charged to consumers.

[23] Note that there are instances where utility regulators review a utility proposal "before the fact." In these circumstances, the commission may review the question of whether the proposed project is needed and is least cost, whether to allow cost recovery, or both.

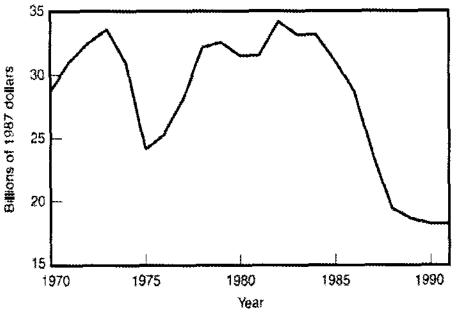
[24] Performance-based ratemaking with compensation tied to outcomes of interest to consumers. Some jurisdictions set rates for utilities under an approach designed to create incentives for the utility to conduct its utility business in an efficient fashion. This is accomplished by establishing a multi-year rate plan with periodic formulaic adjustments in rates. The rate adjustments are designed to create incentives for cost reduction by allowing the utility to share savings with consumers. Going forward, rates are then set pursuant to a schedule of planned adjustments tied to external benchmarks (such as changes in Consumer Price Index or other metrics). The rate plan serves as the framework through which shareholders and ratepayers both absorb risk.

[25] For a more detailed discussion of best practices in competitive procurements, see: Susan Tierney and Todd Schatzki, "Competitive Procurement of Retail Electricity Supply: Recent Trends in State Policies and Utility Practices," prepared for the National Association of Regulatory Utility Commissioners (NARUC), July 2008.

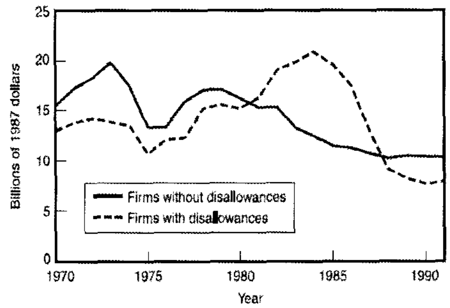
[26] For example, in Texas many competitive retail suppliers enter into bilateral contracts with generators to provide power supply.

[27] "Major cost disallowances by regulators of public utility investments have always been a possibility. In the mid-1980s, however, this possibility came to life in the form of roughly $19 billion of disallowances of electric power plant investments that would otherwise have become part of the utilities' rate bases....Cost disallowances have typically occurred within the context of establishing the utility's rate base. The bulk of these disallowances have been categorized under the heading of management imprudence, but major disallowances have also occurred on the basis of excess capacity (which is not used and useful), and of economic value (in retrospect, alternative sources of power would have been cheaper). ...It was not until the mid-1980s that significant dollar volumes of cost disallowances began to occur in the electric utility industry.[footnote in the original]. Typical disallowances during the mid-1980s amounted to hundreds of millions of dollars, and in two cases (the Nine Mile Point 2 unit in New York and the Diablo Canyon plant in California) regulatory cost disallowances were $2 billion or greater.[footnote in the original]. ... [W]e see that virtually all regulatory cost disallowances occurred beginning in the mid-1980s. Cumulatively, over 50 separate disallowances on 37 different generating units were observed in the sample period, with a total dollar volume of disallowance of over $19 billion.[footnote in the original]." Thomas P. Lyon, and John W. Mayo, "Regulatory opportunism and investment behavior: evidence from the U.S. electric utility industry," RAND Journal of Economics, Vol. 36, No. 3, Autumn 2005, pages 628–644. Figures from the Lyon/Mayo article (pages 630-633):

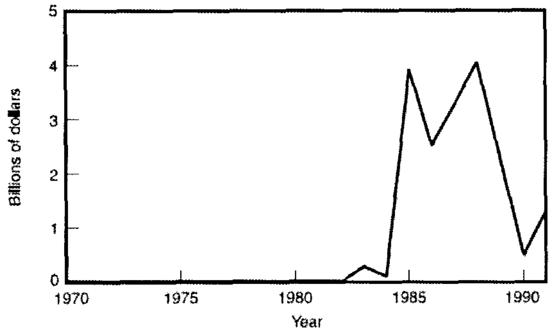
Real Investment by Electric Utilities, 1970–1991



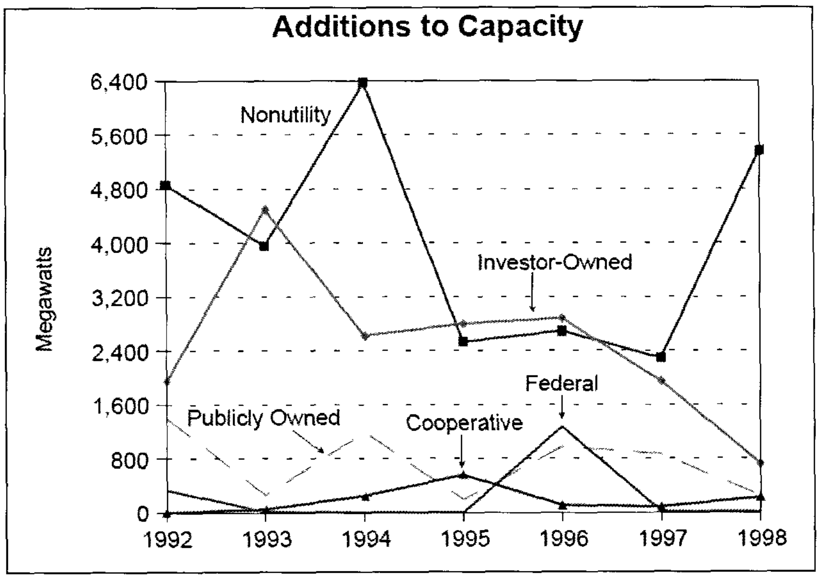

All Firms Real Investment by Electric Utilities, 1970–1991, By Firm Type



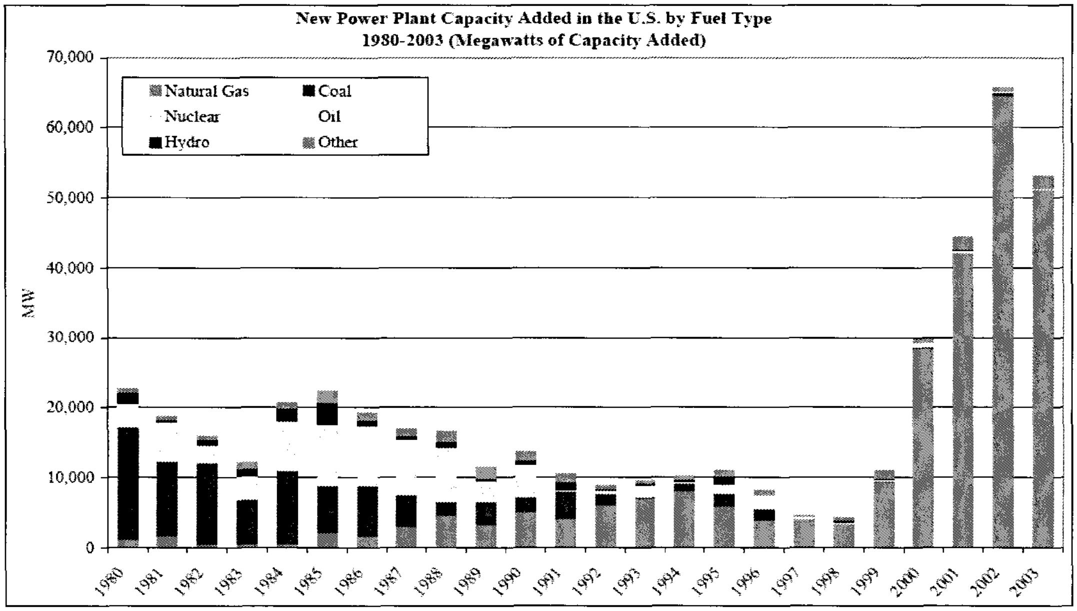

Dollar Values of Regulatory Disallowances, 1970–1991




[28] As noted by Lyon and Mayo, most of the costs that have been disallowed by regulators occurred during the past nuclear investment period. During the 1990s, and following upon the period of nuclear investment disallowances by regulators, most of the generating capacity that was added was done by non-utility generators. (See figure below for the Additions to Capacity (U.S.) during most of the 1990s. Source of figure: EIA, "The Changing Structure of the Electric Power Industry 2000: An Update," October 2000, page 25. )



Most capacity added from 1998 to mid-2000s was natural-gas plants added by non-utility companies (see figure showing megawatts of capacity added by fuel type by year, including during the years of major nuclear additions (and disallowances) in the 1980s):




Source: Tierney, using Platts Basecase data.

29 A clear example of the former can be found in the loan guarantee provisions of the Energy Policy Act of 2005. Title XVII's Loan Guarantee Program authorizes federal loan guarantees to be issued for projects with new or significantly improved technologies that avoid, reduce or sequester air pollutants and that are proposed by sponsors providing a reasonable assurance of repayment. Another example is Iowa's law that allows the Iowa Public Utility Commission to authorized regulators to determine the ratemaking treatment of costs of projects before construction begins. Norman Jenks, "Another perspective: The importance of being certain," *Electric Perspectives*, May/Jun 2003, http://findarticles.com/p/articles/mi qa3650/is_200305/ ai_n9172919/.

30 Susan Tierney is a Managing Principal at Analysis Group, Inc., in Boston, where she is an expert on energy policy, regulation and economics and focuses on the electric and gas industries. A consultant for a 14 years, she previously served as the Assistant Secretary for Policy at the Department of Energy (appointed by President Clinton), Massachusetts Secretary of Environmental Affairs (appointed by Governor Weld), Commissioner at the Massachusetts Department of Public Utilities (appointed by Governor Dukakis), and director of the Massachusetts Energy Facilities Siting Council. She recently co-led the Department of Energy Agency Review Team for the Obama/Biden Transition. She taught at the University of California at Irvine, and earned her Ph.D. and Masters degrees in regional planning at Cornell University. She has consulted to clients in business, industry, government, non-profit and other organizations. She serves on a number of boards of directors and advisory committees, including the National Commission on Energy Policy; chair of the Board of the Energy Foundation; a director of the Climate Policy Center/Clean Air-Cool Planet; member of the Advisory Council of the National Renewable Energy Laboratory, the Environmental Advisory Council of the New York Independent System Operator, and the WIRES' Blue Ribbon Commission on Transmission Cost-Allocation.

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February 2008

# Competitive Electricity Markets: The Benefits for Customers and the Environment

NERA
Economic Consulting

This white paper was commissioned by the COMPETE Coalition, which represents electricity customers, retail suppliers, power marketers, and generators. This paper represents the views of its authors and not necessarily the views of the COMPETE Coalition, its members, or the employer of the authors.

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# FOREWORD

**Alfred E. Kahn**

Robert Julius Thorne Professor of Political Economy, Emeritus,
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Students and serious practitioners of public utility regulation have long recognized what an imperfect institution it is. Grounded in the conception that these industries are naturally monopolistic—that is, that full achievement of their inherent economies of scale requires that they be organized as franchised monopolies—it followed that they had to be regulated in order to protect consumers from exploitation, while at the same time assuring investors recovery of their prudently (more precisely, in practice, their not-demonstrably-imprudently) incurred costs.

This essentially cost-plus system appeared to work well in electric power during the quarter century following the end of World War II, when technological progress and the progressive realization of economies of scale in generation and transmission, and the adoption of nuclear generation, converged to produce declining rates in real terms. In the decades following 1973, in contrast, two bouts of double-digit inflation in the economy at large, two quadruplings of the price of oil, sharp increases in the cost of capital—especially painful in so capital-intensive a business—and massive cost overruns in nuclear facilities all compelled dramatic rate increases throughout the 1980s, just when a slump in the real prices of oil and natural gas and the advent of combined-cycle gas generation made deregulation and competition look far more attractive to consumers than continued compliance with the historic regulatory bargain.

As this brief historical account demonstrates, the movement for deregulation in the last decades of the 20th century was clearly opportunistic—putting pressures on regulatory agencies to renege on their implicit promise to set rates sufficient to provide fair returns on invested capital—a "temptation of the kleptocrats," as I put it at the time.[1] Significantly, the pressures for deregulation were most insistent in states whose electric companies had invested heavily in nuclear plants and, at the other extreme, virtually nonexistent in states still relying heavily on coal, and particularly coal-fired generating plants that had long since been totally depreciated on the companies' books.

But, clearly, there were fundamental, not merely transient issues at stake as well. As I observed some seventeen years ago, in the context of reforming regulatory practice rather than deregulation:

> [A] consistent use of current competitive market valuations, for successful and unsuccessful investments alike, would be not only unobjectionable but desirable, because it would transfer the cost of failures, symmetrically with the profits of success, from ratepayers to investors.[2]

Manifestly, genuine deregulation would produce the same beneficent result.

Deregulation alone, however, would not take into account the especial importance, in this industry—in which only limited storage of its product is possible—of reliability of supply in the face of demand that fluctuates widely. Under regulation, this reliability was secured by requiring generators to maintain some stipulated margin of excess capacity sufficient to hold loss-of-load probabilities down to some acceptable minimum—the cost of which had to be distributed among all customer groups, since all benefited from it.

It was rarely recognized, however, that such a system was itself highly inefficient, because it failed to recognize that *individual customers* have widely differing needs for such assurances, because they differ correspondingly in the ability to adapt their consumption habits to the widely varying marginal costs. Only a system that provides customers with the choice of contracting with suppliers for such assurances as each of them requires—and its corollary, able instead to alter their consumption habits in response to changes in system marginal costs—can accomplish the purpose, on the one hand, of determining what margin of excess capacity is required in the aggregate and, second, how its costs will be distributed among customers. I commend to readers the authors' exposition of how restructured markets would, by confronting customers with prices varying hourly with contemporaneous marginal costs, give them the opportunity to react in real time, thereby giving each the opportunity to choose the level of reliability he or she wants and is willing to pay for.

Just as the move to restructuring was opportunistic, so too is the current sentiment to return to regulation a reaction to transient developments—in particular, the sharp increase in oil and gas prices—driving marginal costs above historic costs. But the choice of system should not be based, opportunistically, on transient events: the real defect of regulation is that rates set under it are based necessarily on averages—over time and among groups of customers. Ideally, the system would confront each customer with the proper price signals. And production efficiency is best realized when investors bear responsibility for investment decisions.

Policy makers confronting pressures to undo the restructuring of the electricity industry would be well advised to base their decisions on the longer-term benefits that will flow from properly implementing competitive markets, rather than on adventitious circumstances driving market prices temporarily above or below regulated rates.

**Endnotes:**

1. Alfred E. Kahn, *Letting Go: Deregulating the Process of Deregulation, or: Temptation of the Kleptocrats and the Political Economy of Regulatory Disingenuousness* (Institute of Public Utilities and Network Industries, Michigan State University, 1998).

2. Alfred E. Kahn, "The Changing Focus of Electric Utility Regulation," *Research in Law and Economics*, Vol. 13, p. 223 (1991)

**Alfred E. Kahn**

# I. EXECUTIVE SUMMARY[1]

State policy makers are reviewing past decisions to promote competition in electricity markets and, in some cases, are debating whether to reverse course. Competitive electricity markets, also known as "restructured electricity markets," refer to the organization of the electric industry in states where utilities no longer have the obligation to plan and build generating capacity, and have often divested generation ownership. The purpose of this paper is to present an objective review of both traditional regulation and competitive electricity markets in order to assist policy makers as they critically assess their policy options.

The end of transition periods featuring rate caps and the onset of market-based retail rates has resulted in price increases for some states. While many have attributed these price increases to a failure of competition, the timing of the price increases is a coincidence and does not equate to causality. Electricity prices, driven by fuel costs, have risen in all states, not just those that restructured their electricity markets. As a result of these price increases, some states are examining their experiences with electric industry restructuring.

Prices derived by competitive markets and rates derived by traditional regulation[2] are fundamentally different, and will produce different outcomes. Over time, competitive markets are widely held to produce the most efficient results in our economy, providing the lowest costs to customers. Markets reward innovation—the search for and discovery, development, adoption, and commercialization of new products, services, organizational structures, processes, and procedures—that meets market demand. In a competitive environment, customers have more control over what they consume and what they pay, price levels will encourage more efficient use of energy, and market prices will encourage more demand response. Economists and experienced regulators, as well as national electricity policy, favor reliance on competitive markets when workable competition is feasible. It is important to evaluate the attributes of the competitive and cost-based regulatory models, and to critically analyze the strengths and weaknesses of each.

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[1] This white paper was prepared primarily by Eugene T. Meehan, a Senior Vice President at NERA, with Wayne P. Olson, a Senior Consultant at NERA. We thank Joshua Rogers for his research and editorial help. The opinions expressed herein are solely attributable to the authors and do not necessarily present a view of the firm or of other NERA professionals.

[2] Traditionally regulated utilities have an obligation to serve under traditional cost-of-service regulation, and to make and implement long-term generation plans in order to provide efficient, safe, adequate, and reliable service over time. It is important to note that even in restructured states, where such a model has been abandoned, there are many residual elements of traditional regulation. Transmission and distribution delivery service prices are regulated, and while customers receive a market-based generation price, the market procurement method is regulated.

Competition facilitates the most efficient means of production. Competitive market pricing provides significant benefits not found under traditional regulatory pricing. Among these benefits are the following:

- Market-based price signals are transparent and can stimulate appropriate infrastructure investment, energy conservation, and demand response.

- Competition provides customers with choices—i.e., customer sovereignty. Customers can exercise their own choices with respect to long-term risks, environmental concerns, and even reliability levels.

- Competitive market pricing allows sellers to tailor products and services to their customers' needs, and use demand-side solutions to avoid supply-side investment where appropriate.

- By pricing at market, prices will be similar for proximate utilities.

- Competition shifts risks from customers to investors.

- Competition produces more efficient results because the investor, not the ratepayer, assumes the generation investment risk.

- In competitive markets, poor producers fail and are acquired or replaced by those with more skill, foresight, and industry.

The electric utility industry pursued competition not for academic reasons, but because regulation was producing unacceptable outcomes, including large price differences between proximate utilities, large plant cost overruns, rate shocks and phase-ins, and customer dissatisfaction with lack of control over their electricity costs. Some innovative pricing concepts were studied, but they were rarely implemented on a large scale, and offerings were limited to a few standard tariffs. New generation built under regulation was considered too risky by both customers and investors, and power plants, particularly nuclear generators, demonstrated poor operating performance.

The differences between cost-of-service regulated rates and prices derived from competition are predictable and certain, and include the following:

- Regulated rates are founded on utilities' and regulators' judgment about the attributes of the product (e.g., reliability, environmental impacts) rather than the discipline of market forces.

- Regulated rates result in utilities and regulators imposing their choices on customers.

- Cost-based regulation makes it difficult for customers to make choices based on their own preferences and responses to market price signals.

- Cost-based regulated prices distort price signals necessary for efficient consumption, and undermine incentives for conservation and demand response. This creates a need to develop complicated and expensive conservation programs that "correct" the price signals through administrative means, when efficient results are obtained with simpler programs and market-derived prices.

Before undoing competitive markets, either intentionally or inadvertently, policy makers should consider the following facts:

- Regulated-monopoly generation imposed huge cost burdens on customers. These burdens, to which customers were exposed under the last significant non-gas capacity expansion, are what led many "high cost" states to restructure. In many states, cost-based regulation failed to produce reasonably priced electricity in the 1980s.

- States continuing with the regulated monopoly model are providing, and must continue to provide, iron-clad cost recovery guarantees for new generation investment.

- Transparent market prices derived in competitive markets are encouraging penetration of energy efficiency (conservation) and facilitating responsive consumer demand, lowering investment needs and providing environmental benefits.

- Innovations in end-use efficiency can potentially be created when customers control their own choices based on available information, and the market provides creative solutions. This can happen to the full extent only in a competitive market.

- Competitive electricity markets have led the way in developing renewable generation.

- Recent price increases are largely driven by fuel price increases, and have occurred in both competitive and traditionally regulated states.

While the promotion of competitive markets may not have been implemented perfectly, the points above suggest that customers would be better served by regulatory efforts directed at refining and improving the competitive model, rather than returning to cost-of-service regulation.

# II. INTRODUCTION

Over $400 billion of electric industry infrastructure investment in generating plants will be required between 2006 and 2030.[3] Investments will be needed not only to accommodate the growth in population and the economy, but to replace aging facilities,[4] reduce emissions, fund research and development of innovative technologies, and lessen dependence on the use of liquid fuels from politically unstable foreign sources. In addition, all of these factors must be viewed in the context of heightened interest in renewable energy.[5] With such a large investment at stake, efficiency must be maximized and customers' interests must be protected. A failure to make this investment in the most efficient manner will: (1) make it difficult to ensure affordable and reliable electricity supply; (2) threaten the global competitiveness of the United States; and (3) risk having the country fall short of achieving environmental objectives.

To induce the needed investment, two economic models—that are markedly different both in terms of how they work and the incentives that they provide—can be used. The first is competition. In competitive markets, investors evaluate alternatives, make investment decisions, and place their capital at risk to market forces. Poor investment decisions lead to investor losses, even if such decisions were reasonable at the time they were made. The second model is cost-of-service regulation. In traditionally regulated markets, decisions about the type and timing of generating plant additions are generally determined by utilities, which are overseen by utility regulators. A utility builds, owns, and operates its system subject to oversight by the regulator through an open process that allows for significant input by stakeholders. While utility investors assume a limited set of investment risks, customers assume more, as they ultimately fund and support the investments through the rates they pay. Customers typically bear the risk when the selected investment incurs relatively higher costs, leading to rates that exceed market levels—so long as the utility's actions were prudent, meaning the actions were reasonable given available information.

At the national level, electricity policy is clear. Federal law provides for competition in wholesale generation markets and open access to transmission facilities. While this policy accommodates wholesale competition, it does not mandate or promote competition at the retail level. States have the choice to rely on vertically integrated utilities to plan, build, and own generating plants; to require utilities to use their monopoly position to underwrite long-term contracts that provide cost recovery without regard to how costs compare to the market in the future;[6] or, to transfer the responsibility for investment decisions and the risk of investment

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3 "[T]otal of 258 gigawatts of new [generating] capacity is expected between 2006 and 2030, representing a total investment of approximately $412 billion (2005 dollars)," *Annual Energy Outlook* 2007, Energy Information Agency, DOE/EIA-0383, 2007.

4 In the Northeastern US, about 41,000 megawatts of generation capacity are due to be retired, which is about one-quarter of generating plant in the region. *See*: Hugh Wynne, *U.S. Utilities: Capacity Retirements, Generation Investment and Technology Choice*, Bernstein Research, August 2006.

5 Over the next five years, renewables comprise about 16 percent of the new generation that has been proposed; wind comprises 88 percent of proposed renewables. *See*: Dan Ford, *Just the Beginning*, Lehman Brothers (Power & Utilities), August 21, 2006, p. 8.

6 The key phrase here is "in the future." Regulated monopolies have to reasonably plan in this day and age, but the standard by which they are judged is whether their decisions were reasonable based on what a prudent utility

decisions away from customers and on to investors by adopting a competitive model. These state decisions on whether to use cost-of-service regulation, competition, or some mix of the two are critical to achieving efficient investment, promoting environmental goals, and protecting customer interests.

Choosing between competition and cost-of-service regulation is not easy. It can be difficult to fully appreciate the consequences of these two options. Given the long-lived nature of utility assets, the choice will have long-term financial and environmental consequences for energy customers. The United States, with its federal system of government, is unique among nations in reserving this major economic choice for the individual states. Policy makers undoubtedly face difficult challenges in the current environment, with price increases largely driven by input price increases, which have little to do with whether or not there are competitive power markets in the state.

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management could have known at the time. If, in the future, the regulated utility's costs become uneconomic relative to the market price, the utility would still be able to recover its actual, prudently-incurred costs in rates.

# III. THE CHOICE BETWEEN TRADITIONALLY REGULATED AND COMPETITIVE MARKETS IS CLEAR

Under competition, prices reflect the supply and demand conditions at the time, and customers have the ability to choose products and services that allow them to manage their individual electricity usage. Under cost-of-service regulation, customers enter into an ongoing long-term contract to support new generating investment through their local utilities, and have very little product choice. Prices reflect historical costs and historical investment decisions, not prevailing market prices.

Competitive market pricing provides many benefits not found under traditional regulatory pricing. First, because investors are compensated based on the market and not cost, they bear the risks and rewards of generation investment. Second, price signals are more accurate within competitive markets, and can stimulate appropriate infrastructure investment, energy conservation, and demand response. Markets use these price signals to evaluate solutions to current and future energy challenges. Third, competitive market pricing allows sellers to tailor products and services to their customers' needs, and use their ability to respond to prices in a way to avoid new investments where appropriate. Lastly, by pricing at market, prices will be similar for proximate utilities. Consequently, industries located in different utility territories will not be subject to arbitrary cost disadvantages relative to competitors, a balance that represents a change from cost-of-service regulation. Under the latter, if one utility decided to build a nuclear plant that resulted in a large but prudent cost overrun, while the neighboring utility decided on a coal plant that was built within budget, rates for the two utilities could differ sharply. This is not typical of functioning markets, and it is difficult for customers, particularly industrial competitors, to accept such arbitrary pricing.

Regulated prices are based on cost of service, and to the extent that different utilities make different investment decisions, prices for proximate utilities may be very different. Throughout the 1980s and 1990s, regulated prices were far above market. Once gas prices declined and technology developments in combined cycle generation lowered cost and heat rates, the cost of nuclear investments and Public Utility Regulatory Policies Act of 1978 (PURPA) qualifying facility (QF) contracts exceeded the cost of constructing and operating new combined cycle plants, or taking advantage of surplus capacity. Prices charged by proximate utilities differed based on the timing of their plant additions and construction cost outcomes.

Luck played a large factor in determining the rates that particular electricity customers paid. But one thing is certain: the major driver for the move to competitive electricity markets in the 1990s was the series of poor outcomes that occurred during the 1970s and 1980s, when the inclusion of "lumpy" investments in nuclear generating plants led to concerns about "rate shock," rate increase, phase-in plans, and automatic pass-through of fuel costs. Ratepayers and investors shared in the financial burden resulting from these investment decisions.[7]

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[7] The economic losses resulting from the mistakes of the 1970s and 1980s may have cost as much as $100 billion. *See*: Wald, "Nuclear Plant Drain Put at $100 Billion for U.S.," *New York Times*, February 1, 1988, p. D1. This article was cited in Richard Goldsmith, "Utility Rates and 'Takings,'" *Energy Law Journal*, Vol. 10, No. 2, 1989, p. 241.

There is little reason to believe that a return to traditional regulation would lead to prices that would be continually below or at market levels. The only assured outcome is that cost-of-service regulated prices will reflect historical costs, not the market. Regulated prices could be administratively set to be relatively stable, but this may come at the cost of consistently failing to reflect the actual costs incurred. It makes little sense to attempt to choose between a traditionally regulated and a competitive model based on expectations of future price level differences, as such a choice would be speculative.

In competitive markets, where larger customers face hourly market prices (and smaller customers may elect to do so), electricity providers in many instances offer creative packages to satisfy customers. These are tangible differences between the traditionally regulated and competitive models that are predictable and certain. It is also certain that under competition, customers will have more control over what they consume and what they pay, that price levels will become known and encourage more efficient use of energy, and market prices will encourage the development of more responsive demand. Moreover, the same benefits apply to supply as well as to demand alternatives. For example, in a traditionally regulated model, wind resources will be viable only to the extent that a utility chooses to build or buy wind. In a competitive market, wind developers will have access to regional transmission organization (RTO) transmission and integration service, and will see market incentives to develop projects that provide maximum market benefits. Correspondingly, consumers may elect to buy more energy from wind and other renewable resources.

In competitive markets, generation investment decisions are made by investors in response to customer needs. Investors bear the risk of those decisions. This is a fundamental and important difference between competitive markets and cost-of-service regulation. It is important to consider that bearing risk does not equate to simply absorbing losses. There is an upside and a downside to risk. In return for bearing losses on unsuccessful investment decisions, investors realize gains on successful investments. That is the competitive model that prevails throughout the US economy.

There are other differences between cost-of-service regulation and competition that are predictable and certain. For instance, regulation requires utilities and, in turn, regulators, to substitute their judgment about the attributes of the product (e.g., reliability, environmental impacts) for that of the market, and this makes it difficult for customers to make choices based on their own preferences. Competition gives customers greater choice and control through market-based innovation. Customers can exercise their own choices with respect to environmental attributes, long-term risks, and even reliability levels. Regulated prices also typically distort price signals that are necessary for efficient consumption, and undermine incentives for conservation and demand response. Since the mid-1970s, traditionally regulated utilities have investigated innovative pricing and demand control. Progress has been limited, as regulated tariffs are standard and creative pricing schemes reflecting individual circumstances are hard to implement.

# IV. ELECTRICITY COMPETITION WAS PURSUED AS A SOLUTION TO LONG-TERM PROBLEMS

Policy makers should consider that electricity markets were restructured because regulation was producing high prices and generally unacceptable outcomes for both customers and shareholders. This section will explain the cost-of-service regulation problems that began in the mid-1970s, which include price differences between proximate utilities, plant cost overruns, rate shocks and phase-ins, PURPA excess costs, and customer dissatisfaction with the lack of control over their electricity costs. Power plants, particularly nuclear plants, demonstrated poor operating performance.[8] Demand side measures and innovative pricing were frequently discussed but rarely implemented successfully in the traditionally regulated environment. By the mid- to late-1980s, there was substantial dissatisfaction with the outcomes of the regulatory process, which led policy makers to pursue competition in the 1990s.

These well-known regulatory problems, which began in the mid-1970s, created a strong impetus for the industry to restructure. A significant component to the problems was price, which, as Professor Paul Joskow of MIT notes, "reflected the high capital costs and poor operating performance of nuclear power plants commissioned during the 1970s and 1980s, the high prices reflected in PURPA/QF contracts, and the costs of excess capacity which got rolled into regulated prices."[9] It is reasonable to assume that the same or similar problems could arise in states that revert to a system akin to traditional regulation. Problems with traditional, cost-of-service regulation of generation are still relevant in many parts of the United States.

US power systems were, for the most part, developed by vertically integrated utilities. These utilities built, owned, and operated distribution, transmission, and generation facilities. Traditionally, these utilities had exclusive service territories and the right to exclude other entities from the use of their distribution and, to a lesser extent, transmission facilities. The generation investment by these utilities was made pursuant to an obligation to serve all loads in the service territory. The legal framework provided for the right to charge rates that allowed the utility a reasonable opportunity to recover all prudent investments and costs incurred to meet that obligation, and further protected that investment with an exclusive service territory and the right to exclude others from the use of distribution facilities.

Major nuclear plant cost overruns received a large amount of press in the 1970s and 1980s. Regulators no longer wanted to deal with overseeing ratemaking issues years after an investment had been made in a plant. To cite some examples:

- In Ohio, construction of the Zimmer nuclear power plant began in 1969, with an estimated in operation date of 1975. Cincinnati Gas & Electric, Dayton Power & Light,

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8 Statistics show that there has been substantial improvement in nuclear operating performance in recent years. This is most easily represented by the increase in average capacity factor across the US nuclear power industry. The Nuclear Energy Institute provides public access to these statistics on its website. Please *see*: http://www.nei.org/resourcesandstats/nuclear_statistics/usnuclearpowerplants/ (Accessed 11/28/07).

9 Paul L. Joskow, *U.S Energy Policy During the 1990s*, prepared for the conference "American Economic Policy During the 1990s," sponsored by the John F. Kennedy School of Government, Harvard University, June 27 to June 30, 2001.

and Columbus and Southern Ohio Electric made up the ownership group, which predicted that the total cost of construction would be $240 million. There were massive cost overruns after construction began, and the estimated total cost rose to $3.5 billion, while the operating date became uncertain. Following allegations of mismanagement and intervention by the Nuclear Regulatory Commission, the owners announced that the plant would be converted to a coal-fired unit with an estimated completion date of 1991 at an additional cost of $1.7 billion.[10]

- In Michigan, construction of the Midland nuclear power plant was expected to be completed by 1975 at a cost of $276 million. Instead, construction of the plant was halted in 1984, after total costs had risen to $4.2 billion. In 1986, the Michigan Public Service Commission decided that the plant should be converted to a gas-fired unit, with a conversion cost of $600 million.[11]

- In New York, construction of the Nine Mile 2 plant began in 1970. The total cost for this project was initially estimated to be under $400 million, and the facility was projected to be operating by 1977. These estimates changed dramatically after construction began, with total costs reaching $3.7 billion and a completion date of 1986. The total cost of the plant after completion in 1986 was $5.4 billion, of which $4.45 billion was deemed recoverable by the New York Public Service Commission.[12]

There are many other examples of cost overruns, which led to a great deal of regulatory frustration over how to better deal with the construction and financing of generation. These frustrations stemmed from problems with nuclear power plants that experienced huge cost overruns, the aftermath of the energy crises of the 1970s, sharply reduced electricity demand growth rates, and the basic fact, that under the traditional regulatory compact, customers bore the vast majority of the risk.

In response to the regulatory issues, state regulators began to emphasize long-term "integrated resource planning" (IRP), which sought to improve on traditional *ex post* regulation by adding an *ex ante* component.[13] IRP began with the best of intentions—to do utility regulation "right," before the fact. Some regulators decided to use a forward-looking regulatory planning process in an attempt to acquire the least costly resources. At the same time, there was a redoubled emphasis on *ex post* scrutiny of the prudence of generation construction programs before new plants were allowed into the rate base.

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[10] Charles F. Phillips, Jr., *The Regulation of Public Utilities* (Arlington, VA: Public Utilities Reports, Inc., 1988), pp. 33-34.

[11] *Id.*

[12] Leonard S, Goodman, *The Process of Ratemaking* (Vienna, VA: Public Utilities Reports, Inc., 1998), pp. 866-867.

[13] Paul Joskow points out that PURPA was "accompanied by the creation of public 'integrated resource planning' (IRP) or 'least cost planning' (LCP) processes to determine 'appropriate' electric utility investment and contracting strategies which were eventually implemented with competitive bidding programs .... The rationale for and economic consequences of these programs were controversial." Joskow, *supra* note 9.

By the late 1980s, many utilities that needed new generation supply were required to procure this supply through competitive bid processes and IRPs. By 1990, 27 states had mandated or allowed the use of utility competitive bidding processes for generation resource procurement.[14] Utility participation in these bidding processes depended on state policy. In some cases, they were required to bid through an affiliate, submitting either a fixed-price bid or a proposal to build a rate-base generating facility, where the costs were not fixed. In either case, they would need to justify the selection of the winning bid to the regulator, and they were competing against non-utility providers.

Under traditional regulation, whether generation was built by the utility or by a new entrant, long-term commitments at ratepayer expense were provided to support the construction of long-term generating assets. If built by the utility, the assumption was that the asset would stay in the utility rate base until it was no longer used and useful, which could be 30-50 years. If built by an independent power producer under PURPA, with pricing based on avoided cost (the cost that the utility avoided by building the generation resource itself), the utility was frequently required to sign a long-term contract—sometimes as long as 15 to 30 years—to support the resource. Moreover, counter-party risk was not always adequately recognized, so the decisions that regulators made as part of the IRP process had major ramifications for utilities, new entrants, and electricity users over very long periods of time.

In addition to nuclear cost overruns, PURPA contracts were also burdening customers. As an example, Regulatory Research Associates notes that "[o]n March 10, 1997, NMK and 19 IPPs announced that a Master Restructuring Agreement was reached 'in principle' to restructure or terminate 44 purchased power contracts" and that "under the MRA, NMK would restructure or terminate the 44 power contracts in exchange for approximately $3.6 billion in cash and/or debt securities and 46 million common shares, representing about 25% of NMK's outstanding common shares."[15]

The experiences of the past are especially relevant today. Plant construction costs have escalated sharply as more utilities are adding generation, making it more important than ever that existing resources be used efficiently, and that demand response and energy efficiency programs be pursued when it is economical to do so. The expected cost of building a new nuclear plant, for example, is escalating as a result of "massive inflation in copper and nickel and stainless steel and concrete."[16] Part of the reason for the 25%-30% increase in the estimated cost of a coal-fired plant is the "huge price increases for the raw materials that plants are made from, including copper and nickel," as well as the cost of finishing those commodities into components.[17] Electricity prices are increasing and, just as in a competitive market, regulation does not shield

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[14] Steven Ferrey, *Law of Independent Power* (Deerfield, IL: Clark-Boardman, 1996), p. 9-3. Ferrey cites the National Independent Energy Producers, "Bidding for Power: The Emergence of Competitive Bidding in Electric Generation," March 1990, p. 11.

[15] Regulatory Research Associates, Inc., *Regulatory Focus – Niagara Mohawk Power Final Report*, April 23, 1998.

[16] *See*: Matthew L. Wald, "Costs Surge for Building Power Plants," *New York Times*, July 10, 2007.

[17] *Id.*

customers from rising input costs. Though costs may be deferred for a period of time due to the regulatory process, they will be recovered so long as they were prudently incurred.

# V. COMPETITION HAS CLEAR ADVANTAGES OVER TRADITIONAL REGULATION AND HAS ALREADY BEGUN TO PROVIDE EFFICIENCY AND ENVIRONMENTAL BENEFITS

Competitive electricity markets allow consumers to choose among providers and service options. This combination of open entry for suppliers and choice for customers provides the benefits of competitive markets (e.g., efficient resource allocation, accurate price signals, and incentives for innovation) and limits competitors' ability to exercise market power. Customers are protected from open-ended commitments to pay above-market costs that would not be passed through in a competitive market. This does not mean that entry into markets will be costless or easy, but rather that all actual competitors, incumbents and new entrants alike, will have made (and potential competitors could make) the investments and commitments necessary for them to compete in the market. Under this system, customers are free to manage long-term risk, which, for example, could include entering into long-term contracts with electricity suppliers.

Under traditional regulation, vertically integrated utilities build new generating plants in order to serve customer demand. Through the regulatory least-cost planning process, utilities are given permission to pursue resource procurement strategies, which effectively commit the regulator to pass the resulting costs through to customers so long as the utility has acted prudently in incurring those costs. This type of utility regulation includes both: (1) an *ex ante* component, requiring the utility to use least-cost integrated resource planning, and to get permission from the regulator before it commits to build or purchase new generating resources; and (2) an *ex post* component, requiring the utility to ask for a rate increase that puts the new plant into the rate base, and allows it the opportunity to earn its opportunity cost of capital on that rate base. Given the utility's obligation to serve, there is a corresponding regulatory obligation to pass through prudently incurred costs to customers, regardless of what those costs would have been in a competitive market.

**Table 1** includes a listing of significant differences between firms that operate in competitive and traditionally regulated models that policy makers should consider when deciding how to move forward.

## Table 1: Competitive Versus Traditionally Regulated Markets

| | Competition | Traditional Regulation |
|---|---|---|
| **Funding** | Company funds investments with the expectation that it will be able to charge customers prices that justify those costs. | Ratepayers fund prudently incurred investments in rate base with a virtual certainty of recovering the costs. |
| **Price Determination** | Prices set in a market by supply and demand with open-ended possibilities for pricing structures, which means choice for consumers. | Prices set based on cost with limited menu of regulated tariffs. |
| **Market Concentration** | Multiple firms compete with one another, with potential competitors providing competitive pressure as well. | Generally one firm, once with a franchise. |
| **What Is Built** | Companies, in response to customer demand, will be more likely to invest in less traditional and more energy-efficient forms of generation, including renewables. | Regulators approve what utilities build. This may or may not be the lowest cost investment, and may or may not be technologically innovative. |
| **Capital Structure** | Less use of leverage perhaps, reflecting greater investment risk, but more potential for innovative financing arrangements. | Traditional utility regulation accommodates the use of more debt, but limits innovation. |
| **Who Bears Risk of Bad Investments?** | Investors. | Consumers. |
| **Market Activity** | The competitive environment is dynamic and subject to entry and exit. This creates a powerful incentive for firms to increase operating efficiency. | Static. Subject to bureaucratic process. |
| **Cost Allocation** | Value branding. Independent power companies have a greater opportunity to market different services to different customers. | Cost averaging. Through the regulatory process, costs incurred are averaged out when determining rates, and the ratepayers that incur specific costs may not necessarily pay for them. |
| **Keys To Success** | Ability to compete on price, terms, and non-price attributes such as billing arrangements and product innovation (such as green power). | Prudence and accountability in decision making; competence working with regulatory and political policy. Ability to overcome market failures. |
| **Vertical Integration** | Greater vertical separation of regulated and competitive activities. | Typically vertically integrated, subject to an internal system of command. |
| **Ownership And Investment** | Risk and return expectations will be relatively higher. This will affect what types of entities hold ownership stakes. | Risk and return expectations will be relatively lower. This will affect what types of entities hold ownership stakes. |
| **Marketing** | Increased need for marketing, and development of innovative products. Focused on meeting individual customer needs through innovation. | Reduced need for marketing and business development. Largely focused on providing one-size-fits-all solutions for customers. |
| **Price Stability** | If price stability is desired by customers, competitive retailers will make such a product available. | The regulatory process eventually allows recovery of all prudent costs. Rates can be slow to respond to changing conditions due to regulatory lag. |
| **Price Signals** | Prices tend to reflect marginal costs, the most accurate representation of opportunity cost. | Retail prices can become distorted from marginal costs through the ratemaking process. |

This table demonstrates the disparate characteristics of competitive and traditionally regulated markets. The fundamentals of a competitive market, such as having more than one supplier, feasible entry and exit, and enhanced price transparency, create these differences. These factors allow competition to spur reductions in operating expenses and increases in innovation.

Traditional regulation, although based on prudently incurred costs, can yield inefficient results, primarily due to the requirement that utility ratepayers bear the majority of risks, rather than investors.

## A. Competition Shifts the Risk to Investors

One of the benefits of restructured markets is that the investment risk for generation plants is shifting from consumers to investors. For instance, after restructuring, there was a huge initial burst of merchant construction in most areas of the country which, despite leading to excess capacity, did not cost customers a dime. This was an especially pertinent topic at the time of restructuring, as there were various notable examples of major cost over-runs in plant construction, especially with nuclear facilities.

Now, with many parts of the country expressing concerns about the adequacy of generation supply, certain states are pursuing policies aimed at providing incentives to build new generation. In competitive markets, wholesale prices provide the incentives to build new infrastructure, with customers free from the obligation to fund those investments. Many traditionally regulated states have recently passed laws providing for prior review of plant—cost recovery guarantees not available to merchant generators—and construction work in progress (CWIP) in rate base.[18] For example:

- **<u>Florida:</u>** In June 2006, legislation that affects several aspects of the state's energy policy was enacted. Senate Bill (S.B.) 888 exempts nuclear power plants from the requirement of a competitive bid and provides for recovery of pre-construction costs and a cash return on CWIP during the construction period of a nuclear power plant. A similar bill, House Bill (H.B.) 549, was enacted on June 12, 2007. This legislation authorizes deferred accounting for the pre-construction costs of integrated gasification combined-cycle (IGCC) plants, and these costs are to accrue a carrying charge equal to the utility's AFUDC rate. All prudently incurred pre-construction costs are recoverable through the utility's capacity cost recovery clause, as is a current return on CWIP.

- **<u>North Carolina:</u>** Senate Bill (S.B.) 3, which was enacted on August 20, 2007, facilitates the NCUC's ability to allow a cash return on CWIP by removing statutory language that had permitted utilities to earn a cash return on CWIP only "to the extent [...] such inclusion is in the public interest and necessary to the financial stability of the utility in question." As an example, the NCUC recently approved the recovery of pre-construction development costs for the proposed Duke Energy Lee Nuclear Station, stating that "to the extent the Commission finds, in a future general rate case proceeding, the specific activities involved in, and the costs of pursuing such Development Work to be prudent and reasonable (whether or not the Lee Nuclear Station is constructed), Duke may

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[18] CWIP in rate base, which provides cash before a plant operates, does not occur in competitive markets. For regulated utilities, there have been instances where commissions have allowed CWIP to be recovered when a regulated utility needs cash flow assistance or when Allowance for Funds Used During Construction (AFUDC) balances, which are "paper" earnings not "cash" earnings, grow large and become burdensome financially. Normally, however, CWIP in rate base is not allowed as the plant is not yet benefiting customers, but in order to induce utilities to build more states are formalizing CWIP allowances.

recover" the Development Work costs in rates.[19] These development costs are expected to total $125 million.

- **Nevada:** In 2004, the PUC adopted revised integrated resource planning rules that permit the Commission to approve an incentive mechanism for generation facilities designated as "critical." Under the rules, the PUC has the option to designate a project as critical if it protects reliability, promotes supply diversity, or utilizes renewable resources. For such a project, the utility may be awarded a financial incentive including: (1) an enhanced ROE on the designated critical facility over the life of the facility; (2) a cash return on CWIP associated with the facility; or (3) the deferral of costs incurred to construct the facility.

- **Wisconsin:** Through an ROE adder, the PSC generally allows a current return on 50 percent of a utility's electric and gas CWIP, except for major generation projects where the PSC generally allows a current return on 100 percent of the CWIP associated with that project.[20]

The trend is clear: the US needs to build new generating capacity, greatly increase energy efficiency, or initiate a combination of both in order to meet demand for electricity and diversify the supply mix away from old technology. Cost-of-service regulation could accomplish this, but going down that path will necessitate iron-clad cost recovery assurances for increasingly expensive generation assets.[21] Regulated entities may be volunteering to build new generation, but not without cost recovery guarantees and payments before plants are in service. While the prior building cycle proved that recovery assurances need to be provided to investors, the amount of price risk faced by consumers does not seem to have sunk in. Customers may not yet be aware of the long-term commitments that are being made on their behalf by utilities and their regulators.[22]

## B. Economic Efficiency Gains

Reliance on competitive markets is based on the principle that firms with the most efficient production and the most value for consumers should and will prevail. Efficient competition leads to production at the lowest achievable costs in the long-term, which is a socially desirable outcome that results in an efficient use of society's resources. Currently, with

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19 Regulatory Research Associates, Inc., Focus Notes, March 30, 2007. A similar approval was granted by the Ohio Public Utilities Commission to American Electric Power (AEP) in 2006, which allowed for the recovery of $24 million in pre-construction costs related to an IGCC facility. *See*: Regulatory Research Associates, Inc., Focus Notes, April 27, 2007.

20 Regulatory Research Associates, Inc., State Commission Overviews, various dates.

21 From May 2005 to October 2006, Duke Energy's estimate of construction costs for two new coal-fired plants at its Cliffside site went from $2 billion to $3 billion. The North Carolina Utility Commission ultimately approved a single plant for $1.8 billion, an 80 percent increase from the initial estimate—and that number is still just an estimate. Similarly, Entergy's cost to re-power its Little Gypsy site was estimated in April, 2007, to cost $1 billion; by July, 2007 this figure had increased by over 50 percent to $1.55 billion.

22 We are not saying that such guarantees and cash flow allowances are unjustified or unnecessary. To the contrary they may be required in regulated situations. The point is that this is a major difference between the regulated and competitive solutions.

transition to competition periods beginning to end, it is too early to determine the ultimate success or failure of electricity competition—but it is possible to see some encouraging trends.

With competition, generation operators' incentives changed dramatically, leading to changes in microeconomic behaviour. Though they may not be immediately evident in prices, benefits are clear in non-price advantages such as greater service variety and the presence of a functioning market for capacity (which promotes efficient investment decisions).

Research papers that focus on measures of efficiency other than price, such as generator efficiency or operating cost reductions, offer a more complete indication of the impacts of competition in the current environment. Research has found that:

- Operating costs of generating plants in states that chose to restructure have been reduced relative to costs of generating plants in states that decided against implementing competition.[23] Plant operators affected by competition reduced labor and non-fuel expenses by about 3%-5% relative to other IOUs and 6%-12% relative to cooperatives or government-owned generation.[24] Similarly, divested generating plants and those subject to incentive regulation mechanisms improved their fuel efficiencies compared to their peers without high-powered incentives.[25]

- One of the benefits introduced by competition in generation was to improve the performance of previously existing generating assets in the face of competition. Availability, non-fuel operating costs, and heat rates improved significantly. Availability of generating capacity has increased over time in both New England and New York. Equivalent availability factors increased significantly in PJM from 1994 to 1998 and have been roughly constant since then with some year-to-year variability.[26] Relatively small efficiency gains—such as a two percent improvement in heat rates—can provide hundreds of millions of dollars of annual fuel savings.

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[23] Fabrizaio, K., N. Rose and C. Wolfram, "Do Markets Reduce Costs? Assessing the Impact of Regulatory Restructuring on US Electric Generation Efficiency," *The American Economic Review*, Vol. 97 No. 4, 2007.

[24] *Id.*

[25] Bushnell, J. and C. Wolfram, *Ownership Changes, Incentives and Plant Efficiency: The Divestiture of U.S. Electric Generating Plants*, University of California Center for the Study of Energy Markets, CSEM WP-140, March, 2004.

[26] Paul L. Joskow, "Restructuring, Competition and Regulatory Reform in the U.S. Electricity Sector," *Journal of Economic Perspectives*, 11(3): 119-138, 1997.

ISO New England, *2004 Annual Markets Report*, 2005, http://www.ksg.harvard.edu/hepg/Papers/ISONE_2004_annual_markets_report.pdf (Accessed 11/2/07).

New York ISO, *2004 State of the Markets Report*, prepared by David Patton, 2005, http://www.nyiso.com/public/webdocs/documents/market_advisor_reports/2004_patton_final_report.pdf (Accessed 11/2/07).

PJM Interconnection, *State of the Market Report 2004*, 2005, http://www.pjm.com/markets/market-monitor/downloads/mmu-reports/pjm-som-2004.pdf (Accessed 11/2/07).

Markets reward innovation—the search for and discovery, development, adoption, and commercialization of new products, services, organizational structures, processes, and procedures—that meets market demand. The role of competitors in the marketplace is to compete on the basis of price and value. While competing on the basis of price is obviously very important, successful competitors can also innovate and offer the customer something better than that offered by standard service. Some value-added services may be related to price, such as information services that improve a customer's ability to manage its energy usage. Value could also be provided in the form of green power, risk management (fixed prices for seasons or a year), bundling of services, or could take a form that is not currently anticipated.

## C. Energy Efficiency and Renewables

Energy efficiency, distributed energy resources (DER) programs, and renewables (e.g., wind) all benefit from transparent markets and the competitive incentives that restructured markets provide. In a competitive situation (with an RTO or ISO), it is more likely that price signals for generation services (energy, capacity, and ancillary services) will be market based, and it is also more likely that service providers or retailers will be involved.

### 1. Market Transparency and Demand Response

Innovative RTO/ISO programs are providing incentives for a wide variety of needed generation and transmission-related resources. The ISO-RTO Council, made up of ISOs and RTOs serving two-thirds of the US market and half of the Canadian market, recently issued three reports documenting the success they have had in terms of managing demand response programs and encouraging renewable investment.[27] The reports note various ways in which RTOs can facilitate renewable development including clear, expeditious, and nondiscriminatory interconnection processes and market-based ancillary services.

Demand response programs that respond to real-time prices can also serve to moderate spot price spikes. Demand response programs work best in transparent markets, which eliminate the need to use an administered-type price, such as avoided cost pricing, which may give very misleading price signals. With a transparent market providing price signals, it becomes possible to fairly evaluate energy efficiency, demand response programs, and renewable resources. Furthermore, ISOs, by definition, have no stake in market outcomes. Because they own no generation, they are neutral with respect to the ownership and types of generating units that operate within their system. The same is not always true for utilities.

### 2. Availability of Information and Price Signals

It is imperative for potential investors in renewable sources of energy to have access to detailed pricing information so that they can judge the feasibility of their projects. In regard to this, and in support of competition, the ISO/RTO Council reported: "ISO and RTO wholesale markets provide price transparency to inform all market participants, including renewable

[27] For more information, please *see*: ISO/RTO Council, Increasing Renewable Resources, October 16, 2007; ISO/RTO Council, Progress of Organized Wholesale Electricity Markets in North America, October 16, 2007; Markets Committee of the ISO/RTO Council, Harnessing the Power of Demand, October 16, 2007.

generation owners, about the price and the value of their power."[28] In addition, the report notes: "[i]n wholesale electricity markets, developers have access to both historical data and forward price curves to estimate the future value of their generation."[29] This lies in stark contrast to projects not in ISO/RTO regions, where it is likely that the developer will negotiate price bilaterally with the utility, and will not have access to public price information.

The availability of time-based market prices and demand response capability can change the energy cost structure faced by certain utility customers during peak periods, resulting in increased consumer price responsiveness (i.e., elasticity). Thus, customers participating in demand response programs benefit from transparent market prices. Through the market process of numerous buyers and sellers making individual decisions, competitive markets allow consumer demands to be sorted out and aggregated by producers at the lowest possible cost. The price information provided by the market gives buyers and sellers the information they need to make their individual production and purchasing decisions. The Markets Committee of the ISO/RTO Council issued a positive review of ISO/RTO management of the demand response programs in the US and Canada, stating that:

> The markets these ISOs and RTOs administer, which represent approximately two-thirds of electricity demand across the United States and just over 40 percent in Canada, are playing an important and growing role in enabling demand response to reach its full potential. They provide visible price signals that will help consumers make rational decisions about expenditures on electricity in the same way they use market prices for deciding how to purchase other goods and services.[30]

Given the price signals provided by a transparent real-time spot market, demand response programs can be more effective in restructured jurisdictions. Efficiency investments are also spurred when customers see true market prices and can make decisions to use energy more efficiently based on those prices.

States with competitive markets can avoid relying heavily on administratively set credits that may not always adjust readily to reflect changes in costs. Administratively set credits have an important defect: they are *static* in nature, while wholesale power markets are inherently dynamic over time. In dynamic power markets, administratively set credits rapidly become stale and can trigger incorrect and outdated responses. One lesson from the implementation of PURPA in the 1980s is that, in the absence of market prices, setting avoided cost rates is a very difficult task to complete correctly. When wholesale market price information is readily available, these challenges are reduced.

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[28] ISO/RTO Council, *Increasing Renewable Resources*, October 16, 2007, p. 11.

[29] *Id.*

[30] Markets Committee of the ISO/RTO Council, *Harnessing the Power of Demand*, October 16, 2007, p. 1.

### 3. Renewable Generation Growth

The records on prices that are maintained by ISOs and RTOs can serve as valuable information to companies deciding whether or not to invest in renewable generation assets. But what has actually happened in recent times, in terms of the *growth* in generation from renewable resources in restructured vs. traditionally regulated states?

**Table 2: Growth of Renewable Generation in Restructured and Traditional States 2000-2005**

| | Growth Rate |
|---|---|
| Restructured States | 11.3% |
| Traditional States | 0.6% |

Source: EIA.

Total renewable generation increased in both markets during the period of time between 2000 and 2005. However, renewable net generation in restructured states increased by approximately 11.3 percent, while there has been an increase of less than one percent in traditionally regulated states. This is not to say that restructuring was completely responsible for the relatively larger increase in renewable net generation in restructured states. To prove this, a multitude of other variables would have to be considered, including overall trends in electricity demand, and separate state policies regarding renewables. These statistics are important, however, given the expectation that independent power providers compete based on short term marginal cost, and that renewables would therefore not be viable competitors. In addition, utilities in restructured markets are not mandated to purchase power from PURPA qualifying facilities.[31] At the very least, the growth in renewable net generation in restructured states shows that the transparent market prices, customer choice, and renewable standards that are available in restructured markets help to provide a favorable environment for renewables.

There have been many recent examples of renewables gaining a stronger foothold in restructured markets. For instance, in Maine, a proposed mountain ridge wind farm has already sold its first 10 years of renewable energy.[32] This project is expected to power 44,000 households and reduce daily air emissions in the region by 430 tons a day. Harley Lee, President of Endless Energy in Yarmouth, issued a statement that highlighted Constellation's role as a power marketer, noting that "[o]ur region has lagged behind other parts of the country in the use of

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[31] As part of the Energy Policy Act of 2005, Congress substantially narrowed the applicability and scope of QF must-buy requirements. Thus, utilities in much of the US will be relieved from the Section 210 requirements applicable to new QF facilities, with a showing that a new QF has nondiscriminatory access to competitive wholesale markets that meet the applicable standard. For utilities that cannot show that the new QF has access to competitive wholesale markets that meet the Section 1253 standard, the PURPA "must buy" requirements will continue.

[32] Donna M. Perry, "Redington Wind Farm has Deal to Sell Power," *Sun Journal*, April 6, 2006.

wind energy. A major reason has been the lack of a power marketer willing to sign long-term contracts."[33]

Other positive examples of renewable energy in restructured states include an agreement between Constellation and Horizon Wind Energy for an 18-year renewable energy power purchase agreement,[34] a contract between Epuron LLC (Conergy) and Exelon Generation for a 20-year power purchase agreement for the energy produced at a proposed 3 megawatt (MW) solar energy power station in Morrisville, Pennsylvania,[35] and the success of PECO Wind in Pennsylvania.

## VI. CONCLUSION

State policy makers face a difficult situation. Restructuring transition periods have ended or are ending as prices are rising across the country. Prices have generally been rising over the past several years, regardless of market structure, primarily because of rising input fuel prices. At the same time, investment needs are growing and environmentally beneficial renewables are being mandated by legislation. Carbon emissions, which are not limited at all now, could be limited moving forward, which will further increase prices. Upward pressure on natural gas and oil prices show no signs of relenting. Even generation equipment costs are rising as the metals needed for their manufacture increase in price, and as demand drives up engineering and construction labor costs. Price increases are unpopular, and in the search for a villain, it is easy to blame competition. The facts, however, do not support the hypothesis that competition is the cause of price increases. The rise in oil and gas prices, equipment costs, impending carbon control costs, and the mandate to replace older and dirtier generation with alternative units are the primary factors behind these price increases. Both competitive and traditionally regulated states are seeing the impact of input price increases.

It is true that restructuring was misunderstood and, in many cases, unrealistic expectations may have been set. The implication that restructuring would always lead to lower prices was not accompanied by the obvious "all else being equal" or "over the long term" provisions. Abstracting from oil and gas prices, renewable mandates, equipment cost increases, and carbon reduction costs, it is likely that prices in restructured states would have declined as transition periods ended. But that did not happen, and industry structure cannot compensate for sharp increases in input prices.

In theory and in practice, restructured markets are superior in providing production efficiency incentives, in encouraging efficient demand side activity, and in encouraging investment in alternative forms of generation. We also know that in competitive markets customers bear much less risk. These factors all point to a policy that favors competition over

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[33] *Id.*

[34] Constellation Energy, *Constellation Energy to Purchase Wind Power From Horizon Wind Energy's Twin Groves II Project*, July 25, 2007, http://ir.constellation.com/phoenix.zhtml?c=112182&p=irol-newsArticle&ID=1030961&highlight= (Accessed 11/2/07).

[35] *Epuron, Exelon Join Forces on 3 MW Pennsylvania Solar Facility,* RenewableEnergyAccess.com, September 4, 2007, http://www.renewableenergyaccess.com/rea/news/story?id=49828 (Accessed 11/2/07).

cost-of-service regulation. Electricity generation is a capital intensive industry with long lead times, and the benefits of competition cannot be expected to be seen overnight.

We also know that cost-of-service regulation performed poorly during the last major generation building cycle. However, these lessons, while very relevant, may not stand out to current policy makers who were not involved in the industry in the 1970s and 1980s. Competition, with all its imperfections and transitional problems, is too often compared to an idealized version of regulation that may exist in theory but not in practice.

Before rushing to judgment on restructuring and undoing competitive markets, policy makers should consider the following facts:

- Competition and cost-of-service regulation are fundamentally different and competition will shift risk from customers to investors.

- The risks borne by customers and the outcomes they were exposed to under the last significant non-gas capacity expansion are what led states to restructure. In many states, cost-of-service regulation failed in the 1980s.

- States continuing in the cost-of-service regulated model are providing iron-clad cost recovery guarantees for new generation investment and prudence pre-approval.

- The market prices seen in competitive markets will encourage efficient penetration of energy efficiency (conservation) and facilitate demand response, lowering investment needs, and providing environmental benefits.

- Competitive markets have led the way in renewable energy development.

- Recent price increases are largely driven by input price increases, and have occurred in both competitive and traditionally regulated states.

While restructuring may not have been perfectly implemented and there will always be room for improvement, the facts above suggest that regulatory efforts would be better directed at refining and improving the competition model rather than returning to the cost-of-service regulated model.

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## Competitive Electricity Markets Drive Renewables, Demand Reponse, Conservation, Efficiency and Innovation

Today, more than two-thirds of the nation's electricity consumers live or do business in states that are part of regional competitive electricity markets. Organized competitive markets provide high-quality information - embedded in price signals that reflect the forces of supply and demand - and place a premium on efficient resource use. When coupled with well-designed rules, organized markets provide proper incentives to traditional energy providers to use more efficient technologies that pollute less and allow renewable energy providers to innovate and grow. Taken together, this means cleaner air and more environmentally friendly choices for consumers.

**Organized Regional Competitive Electricity Markets Promote Renewable Generation**

- Renewables have flourished in organized regional competitive markets as compared to non-restructured markets:
  - Renewables growth rate in restructured states (2000-2005): 11.3percent
  - Renewables growth rate non-restructured states (2000-2005): 0.6 percent[1]
- The growth in renewable net generation in restructured states shows that the transparent market prices, customer choice, and renewable standards that are available in restructured markets help to provide a favorable environment for renewables.[2]
- Wind power has grown disproportionately in organized regional competitive markets.
  - Over the past decade, there has been nearly 3 times as much wind energy produced in regional competitive markets than non-restructured markets.
    - In total, wind energy produced has increased 15.8 times over the period between 1997 - 2008. Of this increase, roughly 2/3 has occurred in RTO states.[3]
    - "Overall, wind generating capacity located within the 10 ISOs/RTOs has increased four-fold since 2004."[4]
  - As of 2009, nearly 80 percent of wind resources are located in the RTO markets.[5] Yet only 44 percent of wind energy potential and only 53 percent of electric demand is found in those areas.[6]
    - The large geographic footprint of regionally administered transmission systems and markets, and their diverse portfolios of dispatchable generation, is very accommodating of the variable nature of wind generation.
  - 7,258.5 MW (85%) of the 8,545 MW of wind capacity that was constructed in 2008 came from competitive suppliers.[7]
  - 6,929.3 MW (81%) of the 8,545 MW of wind capacity installed last year was constructed in organized markets.[8]

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[1] *Energy Information Administration.*
[2] *"Competitive Electricity Markets: The Benefits for Customers and the Environment", National Economic Research Associates, Inc. (NERA), February, 2008.*
[3] *Energy Information Administration, Form 906.*
[4] *"2009 State of the Markets Report," ISO/RTO Council, September 2009.*
[5] *Id..*
[6] *"Facilitating Wind Development: the Importance of Electric Industry Structure," B. Kirby & M. Milligan, National Renewable Energy Laboratory (NREL), May 2008*
[7] *American Wind Energy Association (AWEA) Annual Wind Industry Report, 2009; North American Electric Reliability Corporation (NERC) Accommodating High Levels of Variable Generation Report, 2009*

- In all, nearly 130 new wind power plants were constructed in 2008, with over 100 of them constructed by competitive suppliers and nearly 100 in organized wholesale electricity markets.[9]

- The large wholesale markets enable a more effective exchange of services and compensation for all electricity generators, including wind power generators, helping them compete for larger shares of generation markets. Experience has shown that using well-functioning hour-ahead and day-ahead markets and expanding access to those markets are effective tolls for dealing with wind's variability. A deep, liquid real-time market is the most economical approach to providing the balancing energy required with wind plants with variable outputs.[10]
- Regional competitive markets offer unique opportunities for wind and other variable, renewable generation, including spot markets for balancing supply and demand in real-time, elimination of "pancaked" rates between utilities, and regional transmission plans.[11]
- Traditional inefficiencies and balkanization found in power grids are largely remedied by competitive electricity markets, alleviating discrimination against new and renewable energy sources.[12]

**Competition Promotes Demand Response, Conservation and Improved Efficiency**

- Competitive market price signals allow regional system operators and consumers to measure the value of demand response (the voluntary reduction of electricity use) and thereby provide a solid foundation for demand response growth.
  - During 2007, 8 percent of energy consumers in the United States participated in some kind of demand response program and the potential demand response contribution from all such programs reached close to 41,000 megawatts, or 5.8 percent, of U.S. peak demand. This represents an increase of about 3,400 MW from the 2006 estimate.[13]
  - PJM's October, 2007 Reliability Pricing Model (RPM) capacity auction cleared 893 megawatts (MW) of demand response, which is about the amount of capacity provided by a large power plant. In PJM's auction, demand response competes with, and is paid the same, as generation.[14]
  - NYISO has over 1,800 MW of demand response and almost 400 MW from customers registered to offer their load reductions into the wholesale market on a day-ahead basis. Demand-response resources represent 5.4percent of NYISO's 2007 forecast summer peak load. [15]
  - As of September 2007, more than 1,200 MW of demand response are being used to protect power system reliability in New England.[16]
  - During the 2006 heat wave, a total of 2,700 MW from emergency demand-response programs and voluntary conservation helped keep California's electricity running.[17]
  - Every day, ERCOT utilizes 1,150 MW of "Loads acting as Resources" to help ensure system reliability.[18]
- Competition has improved the operating efficiency of power plants, resulting in cost savings, fewer refueling outages, and enhanced reliability.[19]

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[8] *Id.*
[9] *Id.*
[10] *20% Wind Energy by 2030: Increasing Wind Energy's Contribution to U.S. Electricity Supply, U.S. Department of Energy, May 2008*
[11] *Letter from AWEA, NRDC, et. al. dated February 26, 2007 to FERC Chairman Kelliher, et al.*
[12] *Id.*
[13] *"2008 Assessment of Demand Response and Advanced Metering Staff Report," Federal Energy Regulatory Commission, December, 2008.*
[14] *"PJM Reliability Pricing Model Attracts More Generation, Demand Response," PJM Press Release, October 12, 2007.*
[15] *"Increasing Demand Response and Renewable Energy Resources: How ISOs and RTOs are Helping Meet Important Public Policy Objectives." ISO/RTO Council, October 2007.*
[16] *Id.*
[17] *Id.*
[18] *ERCOT protocols Section 6.5.4 (8)*
[19] *"Putting Competition Power Markets to the Test - The Benefits of Competition in America's Electric Grid: Cost-Savings and Operating Efficiencies", Global Energy Decisions Study at ES-1, (2005); Howard J. Axelrod, The Fallacy of High Prices, 144 Public Utilities Fortnightly at 55 (Nov. 2006).*

    - Competition has promoted "substantive" efficiency improvements in U.S. electricity generating plants, with generating plants owned by municipalities and cooperatives (insulated from market reforms) experiencing the smallest gains in operating efficiencies.[20]
- Investment in new, efficient generation spurred by competition has resulted in a reduction in the use of older, less efficient and higher emission power plants, delivering both economic and environmental benefits to consumers. "Competition has fostered construction of efficient power plants with lower heat rates and lower operations and maintenance costs than older existing units ... Operation of these more fuel-efficient generation resources has not only put downward pressure on power prices, it has also helped reduce CO2 and other emissions."[21]
    - Renewable generators account for 142,711 MW of the 326,429 MW of generation in the ISO and RTO interconnection queues.[22]
    - Most of the new construction within the NYISO has been high efficiency, natural gas-fueled, combined cycle combustion turbine units which will offset less efficient and less environmentally friendly units.[23]
    - The move to more efficient gas-fired generators has decreased the use of New England's oil and older gas power plants, and from 2001-2004 is estimated to have reduced annual carbon dioxide emissions by 6%, nitrogen oxide emissions by 32 percent, and sulfur oxide emissions by 48 percent.[24]

**Competition Promotes Technological Innovation**

- Organized regional competitive markets have become an incubator for technologically innovative energy products and services that respond directly to customer preferences.
- Regional electricity market operators have installed the most advanced systems in the industry for network analysis, monitoring, operations planning, scheduling, and forecasting, and are on the cutting edge of technological innovations involving grid management and delivery of energy services.[25]
- Wider use of price-responsive demand is expected to boost the competitiveness of wholesale electricity markets, enhance grid reliability and improve efficiency of resource use. Technology and regulatory options that enable customer energy management are gaining momentum because of increasing support from electricity regulators, regional transmission operators (RTOs) and retail electricity providers. Several consumer-driven energy trends could have a significant impact on wind development.[26]

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[20] *"Do Markets Reduce Costs? Assessing the Impact of Regulatory Restructuring on US Electric Generation Efficiency," Kira R. Fabrizio et. al., September, 2007.*

[21] *"2009 State of the Markets Report," ISO/RTO Council, September 2009.*

[22] *"Increasing Renewable Resources: How ISOs and RTOs are Helping Meet This Public Policy Objective." IRO/RTO Council, October 16, 2007.*

[23] *"ISO Power Trends: 2005", the New York Independent System Operator, April 2005.*

[24] *"Progress of New England's Restructured Electric Industry and Competitive Markets: The Benefits of ISOs and RTOs", ISO New England, April, 2005.*

[25] *For example, new generation scheduling software, which allows PJM to schedule more accurately the hours that generating units must be ready to run, was projected to save customers about $56 million annually. PJM News Release (June 24, 2004).*

[26] *20% Wind Energy by 2030: Increasing Wind Energy's Contribution to U.S. Electricity Supply, U.S. Department of Energy, May 2008*

March 2008

# Innovation in Retail Electricity Markets: The Overlooked Benefit

## Executive Summary

**National Economic Research Associates, Inc.**

This white paper was commissioned by, in alphabetical order, the Compete Coalition, Constellation New Energy, Direct Energy, Green Mountain Energy, Hess Corporation, Integrys Energy Services, Reliant, Strategic Energy, and Suez Energy Resources NA, Inc. However, this paper represents the views of the authors only and not necessarily the views of any of the entities cited above or any other professional at National Economic Research Associates, Inc.

# INNOVATION IN RETAIL ELECTRIC MARKETS: THE OVERLOOKED BENEFIT – EXECUTIVE SUMMARY

The United States retail electric market is at a critical stage in its evolution. Retail markets are providing benefits to consumers in the form of new products and services and innovative methods of providing service. Despite this evidence some analysts and regulators have expressed a desire to return to a more regulated, less open market place in which government bodies dictate investment decisions and customers are not provided the opportunity to take control of their own consumption decisions.[1] Much of the concern with retail electric markets apparently stems from naïve comparisons of price without any real attempt to understand and evaluate other factors influencing customers' demand for and choices of services. Few consumers make consumption decisions based solely on price without taking into account quality, convenience, or novelty. Yet much of the debate over electricity restructuring *assumes* customers care nothing about the characteristics of the products and services they buy or the characteristics of the providers of these services.[2] Without evaluating these other aspects of the marketplace, we are left with an incomplete and distorted picture of the true nature of restructured markets. Customer choice is more than just price, it is just as important for customers that products provide convenience, quality, environmental attributes and control over their usage. To ignore this and turn away from customer choice would reduce the incentive for suppliers to provide innovative services leaving customers with fewer choices and, in turn, lowering overall customer benefits.

While dueling experts can provide different views on whether competitive forces have produced "lower" rates, what is lost in this politically charged debate is a significant benefit of restructured markets that often goes without discussion—innovation. The purpose of this paper is to explore the nature of innovations that customers have demanded and competitive suppliers are providing. The evidence from the more advanced retail electric markets, shows that customers do not necessarily want the "plain vanilla" electric service that has been provided by the traditional regulatory process--a process in which the desires of customers can often get lost. Alternatively, markets focus on satisfying the varying characteristics of the needs and desires of customers. Customers are not uniform in nature; they have varying degrees of risk tolerance, interest in convenience, flexibility in use and desire different levels and types of service. As originally conceived, competitive retail electric markets were implemented with the customer in mind. It was thought that the rivalry between different firms competing for customers would ultimately benefit the consumer through:

[1] This white paper was prepared primarily by Dr. Karl A. McDermott, a Vice President at NERA and Dr. Carl R. Peterson, a Senior Consultant at NERA. We thank those that commissioned this paper for providing data to support this work. We also thank the many reviewers that provided comments on the initial draft of this paper. However, the opinions expressed herein are solely attributable to the authors as are any errors or oversights.

[2] In this report we will use the terms *restructured* or *restructuring* to refer to wholesale and retail electric markets where government-imposed entry restrictions have been removed or lessened. This may also allow for customers to obtain non-discriminatory access to different suppliers of electricity and energy-related products and services. Where we discuss *perfectly competitive* markets we are referring to a specific economic theory. Perfectly competitive markets are characterized by free entry, constant technology across firms, a homogenous product, price taking behavior on the part of firms and prices set at marginal cost in the long-run.

- Increased and varied number and types of products;
- Increased use of innovative technologies;
- Diffusion of technologies, products, services and management techniques from other industries.

This report finds that this is indeed the case. In examining the services offered in restructured retail electric markets we find that the products offered do go beyond simple price comparisons. It is no understatement to suggest that the modern capitalist economy thrives largely due to the changes in technological opportunities over time. However, innovation itself is often perceived as solely the purview of the engineer or scientist, but in an economic and practical sense it has a much broader definition. Innovation certainly includes the creation and commercialization of new products, gadgets or technologies, however innovation also embraces management and marketing novelties that provide enhancements and diversity in delivery and packaging of services to customers. In an age dominated by commoditization, customers seek the ability to obtain customized products that fit specific needs that the "plain vanilla" service cannot fill. Additional product diversity is being created through pricing, billing, metering, and service innovations. It also includes the diffusion of innovation services, management techniques and services from one market to another.

Retail markets appear to be delivering on the promise of new, varied and innovative products and services. The products and services that fall into four broad categories:

- **New Pricing Options:** Many of the innovative financial arrangements are based on the diffusion of innovations from wholesale electric markets and other financial markets. Providing customers access to forward markets, spot markets and other financial arrangements represents an innovation in retailing that was brought about because of the restructuring of markets.
- **Clean Energy Products:** It is apparent from our research that one of the key aspects of innovation in the retail market is related to clean energy products that go beyond the simple selling of electricity produced by environmentally benign sources. Retailers are providing customers with services that allow them to brand their own products, integrate a new ethic into production processes, and take advantage of environmentally beneficial cost saving opportunities such as demand response and energy efficiency options.
- **Innovative Technological Solutions:** These solutions include the use of internet/software solutions for energy management as well as more traditional technology solutions such as HVAC and local control technologies.
- **Customization:** These products and services are those that resemble traditional services, but are provided in new ways. This may include re-bundling, partial bundling or variations of energy-only products.

Specific examples of the products and services include:

- **Clean energy services**: These products include variations on green power offerings, carbon offsets and renewable energy credits, demand response products and services, energy efficiency and facilities management, as well as advisory services for obtaining grants and other related offers and general eco-branding services.

- **Advisory and consulting services:** These services include total energy management products and services, innovative technologies and use of innovative technologies such as web-based software and analytics, energy management and controls and information and data products and services predicated on the use of Advanced Metering Infrastructure

- **Electricity and fuel price hedging products and services**: A variety of pricing options is being provided along a continuum from totally fixed price to real-time pricing and nearly everywhere in between. In addition, fuel based pricing and other hedging products and services are being provided such as indexing and collars.

Table ES- 1 presents a summary of the results of this research. This table maps a set of expected benefits from retail competition (i.e., "Value Category") with customer type and illustrates the services that retail markets are currently providing. Some of these products and services represent new approaches to providing existing services while others are entirely new products and services. In addition, this report finds that the variation within these categories of services is generally large, which suggests that retailers are exploring customers' needs and providing services that are tailored to meet those needs. While many of these products and services are provided to large volume customers, we have found evidence that mass market customers are also benefiting from innovative product and service offerings in some jurisdictions in the United States, notably in Texas and New York. We have also found evidence from competitive retail electric markets in other countries suggesting that mass markets can indeed be served in innovative and effective ways by retail competition.

Regulation of the United States electric markets is at a crossroads. There are some who advocate a return to regulation or a version of regulation to "fix" perceived problems. This report has identified where markets are successful in meeting customers' needs by providing a variety of innovative products and services. This has occurred despite the fact that competitive markets have not fully evolved at this time. In addition, political and market design issues faced by regulators are complex and will require some time to work through. The continued erosion of regulatory barriers and the support of market institutions toward the goal of fully functional markets should be the objective of regulatory changes, not the retreat from market institutions. While the promise of the competitive market is still to be fully realized, from this review of the market the road ahead seems clear: those jurisdictions that continue to support and promote competitive retail electric markets will benefit from the innovation and ingenuity of different suppliers as they compete to provide customers with the products and services that are best suited to those customers.

**Table ES- 1: Retail Product Offerings**

| Value Category | Customer Type[1] | Products Currently Offered by Retail Electric Suppliers[2] |
|---|---|---|
| Reducing the Cost of Retailing Electricity | Price/Value/Bottom Line | Internet gateways/software enabling use of retail products |
| Superior Wholesale Procurement | Price/Value/Bottom Line | Discounted to price to beat/standard offer |
| Installation of Metering Equipment | Value/Bottom-Line/Price/Convenience | Smart grid technology use |
| Price Hedging for Customers | Value/Bottom-Line/Price/Convenience | Fixed Price<br>Partial fixed/bandwidths<br>Day Ahead |
| Other Hedging Services | Value/Principled/Security | Budget Control Products<br>Power Portfolio Planning |
| Behind the Meter Applications | Security/Value/Bottom Line | Facilities control/demand control<br>Distributed generation |
| Green Power | Principled/Value/Security | Renewable energy<br>- Commodity<br>- RECs/Green Tags[3]<br>- Green Brand<br>Demand response<br>- Control technologies<br>- Software<br>- Services<br>Energy Efficiency<br>- Performance Contracting<br>- HVAC (all sectors)<br>- Green buildings<br>- Facilities management<br>- Home Automation<br>Carbon Footprint<br>- Audits and Analysis<br>- Carbon Calculators<br>- Offsets |
| Total Energy Management Services | Principled/Value/Security Buyers | Portfolio services |
| Promote More Efficient Wholesale Markets | Value/Principled | Real Time/Indexed/Demand Response[4] |

(1) Institutional buyers may fall in any category.
(2) Data collected by authors' for this report. Data is publically available on retail suppliers' web sites and promotional brochures.
(3) REC = Renewable Energy Credits
(4) Many of the other products will also promote wholesale market efficiency.

## About the Authors

**Dr. Karl A. McDermott** is a Vice-President in NERA's Chicago office where he specializes in public utility regulation. Dr. McDermott has advised many different clients in both the public and private sectors on issues regarding electric restructuring, market performance and performance-based regulation. He has also assisted the country of Poland with efforts to privatize and restructure the electric supply industry. Prior to joining NERA, he served as Commissioner on the Illinois Commerce Commission during the negotiation of the Illinois restructuring law. Dr. McDermott initiated the Commission's investigation into the alternative restructuring options and has lectured on numerous occasions on restructuring and utility pricing issues in the United States. Dr. McDermott is currently on the faculty of the Institute for Public Utilities at Michigan State University where he lectures at the Institute's Annual and Advanced Regulatory Studies programs. Dr. McDermott has also lectured extensively in Eastern Europe and South America on regulatory reform and restructuring and has published articles in *The Electricity Journal, Natural Gas and Electricity,* and has contributed to numerous book chapters and authored or co-authored reports for the Illinois Commerce Commission, the Edison Electric Institute, the US Department of Energy, the National Regulatory Research Institute as well as the governments of several eastern European countries. Dr. McDermott earned his Ph.D. in economics from the University of Illinois at Urbana-Champaign, a M.S. in public utility economics from the University of Wyoming and a B.A. in economics from Indiana University of Pennsylvania.

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# Competitive Procurement of Retail Electricity Supply: Recent Trends in State Policies and Utility Practices

NARUC

The National Association of Regulatory Utility Commissioners

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July 2008

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# Competitive Procurement of Retail Electricity Supply: Recent Trends in State Policies and Utility Practices

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**Boston, Massachusetts**
**July 2008**

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# EXECUTIVE SUMMARY

## COMPETITIVE PROCUREMENT OF RETAIL ELECTRICITY SUPPLY: RECENT TRENDS IN STATE POLICIES AND UTILITY PRACTICES

Over the past two decades, electric distribution utilities[1] have increasingly relied on competitive procurements as a means to obtain power supply for their retail customers. In many states, regulators now rely on such procurements as an important tool to help ensure that utilities provide cost-effective retail services. Today, more than 40 percent of U.S. states (or jurisdictions)[2] have formal regulations or guidance that requires or encourages utilities to use competitive processes. Although the use of competitive procurements to obtain supply for retail customers is not new, many of the requirements affecting when and how competitive procurements are to be used have either been newly enacted or substantively revised in recent years.

With this growing attention on the design and use of competitive procurements, the National Association of Regulatory Utility Commissioners ("NARUC"), in collaboration with the Federal Energy Regulatory Commission ("FERC"), asked Analysis Group to study state and utility policies and practices for competitive procurement of retail electric supply. Focusing on states that have formally adopted policies or guidelines for competitive procurements, we have collected information on current procurement approaches and practices. We have developed criteria for evaluating procurements, reviewed various procurement methods, and identified recent trends in state policies and utility practices. In this paper, we describe "lessons learned" and – where possible – best practices for designing and implementing competitive procurements in different regulatory contexts and industry settings.

Competitive procurements can provide utilities with a way of obtaining electricity supply that has the "best" fit to customers' needs at the "best" possible terms. In principle, competitive procurements accomplish this goal by requiring market participants to compete for the opportunity to provide these services. However, for competitive procurements to fulfill their promise, they must be designed and implemented in a manner that fosters competition among market participants, including potentially the regulated utility and its affiliated companies. To achieve robust competition, procurements should aim to meet certain criteria:

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[1] In our report, we use the phrase "utilities" to describe the distribution utility in its role of assuring adequate supplies for retail electricity customers.

[2] States with formal rules or guidance include Arizona, California, Colorado, Connecticut, Delaware, the District of Columbia, Florida, Illinois, Maine, Maryland, Massachusetts, Montana, New Jersey, New York, Ohio, Oklahoma, Oregon, Pennsylvania, Utah, and Washington. Some other states, such as North Carolina, have less-formal policies and/or have case precedent directing utilities to have tested the market if they propose to build a new generating facility.

## EXECUTIVE SUMMARY

- **The procurement process should be fair and objective.** A fair and objective process can avoid intended or unintended biases that may prevent selection of the "best" alternatives. The integrity of such a process encourages the participation of third-party suppliers by providing them with confidence that their offers will be fairly considered on their merits. To achieve this goal, procurements must include appropriate safeguards to prevent undue preferential treatment of any offers, to ensure that procurements are implemented as designed, and to ensure that unforeseen circumstances are addressed in manner that is fair and fundamentally consistent with the competitive intent of the process.

- **The procurement should be designed to encourage robust competitive offerings and creative proposals from market participants.** To encourage a competitive response, market participants need to have: (1) confidence that their offers will be considered fairly and objectively; (2) assurance that their confidential information will be reasonably protected; and (3) access to adequate information about bidder requirements, product specifications, model contract terms, evaluation procedures, and other factors that would affect the resources they choose to offer.

- **The procurement should select winning offers based on appropriate evaluation of all relevant price and non-price factors.** Selecting the "best" offer(s) requires first identifying appropriate evaluation criteria and then evaluating the offers objectively against them. Designing an effective evaluation process is inherently challenging when such evaluations require comparisons of an array of price and non-price factors. In particular, many of these non-price factors are quite complex to quantify and/or qualitative in nature. By contrast, procuring products that meet standardized specifications (such as full requirements service for standard-offer-service customers in states with retail choice) greatly simplifies the evaluation process by allowing for the selection of winning offers based on price terms alone.

- **The procurement should be conducted in an efficient and timely manner.** Procurements should avoid unnecessary administrative costs that may discourage market participants, create transaction costs that produce price premiums in supplier offers, and ultimately impose greater costs on ratepayers.

- **When using a competitive procurement process, regulators should align their own procedures and actions to support the development of a competitive response.** Regulators' own actions can positively – and in some cases, negatively – affect the integrity of a competitive procurement process. Positive signals can arise, for example, by doing what is legally possible to protect the confidentiality of commercially sensitive information submitted through supply offers, by conducting regulatory reviews in a time frame that supports the "best" price terms in offers, and enforcing elements of the procurement design that enhance the overall fairness and objectivity of the process and the integrity of the procurement results.

In practice, the challenges to designing procurements that meet these criteria depend greatly upon the nature of the products being procured. As described in Table 1 and explained more fully in this report, some states and utilities use competitive procurements to obtain new sources of supply to add to the utility's existing portfolio, while others use them to obtain all supply for retail customers. This basic difference has quite distinct implications for the design and implementation of competitive procurement processes.

<table>
<tr><th colspan="5">Table 1<br>Frameworks for Procurement of Electricity Supply for Retail Customers</th></tr>
<tr><th>Electric Industry Structure</th><th>Divestiture of Power Plants</th><th>Procurement Framework / Product Solicited</th><th>Supply Portfolio Management</th><th>State Examples</th></tr>
<tr><td>Traditional</td><td>None</td><td>Incremental Supply – typically for resources from a specific power plant obtained through requests for proposals ("RFPs")</td><td>Utility</td><td>CO, GA, LA, OK</td></tr>
<tr><td>Restructured, No Retail Choice</td><td>None or Partial</td><td>Incremental Supply (via RFP)</td><td>Utility</td><td>CA, MT</td></tr>
<tr><td rowspan="2">Restructured, with Retail Choice</td><td rowspan="2">Full<br>(or near full)</td><td>Full Requirements Service ("FRS") (via auctions or RFPs) to provide retail supply for basic service customers</td><td>Market</td><td>MA, MD, ME, NJ</td></tr>
<tr><td>Hybrid FRS Frameworks:<br>• Long-term contracts (with FRS procurement)<br>• Utility ownership of generation, with some degree of portfolio management by the utility<br>• Public power authority<br>• Specialized procurements (e.g., renewables or renewable energy credits)</td><td>Variously Assigned to Market and to Utility</td><td>CT, DE, IL, OH, PA</td></tr>
</table>

In states with a more traditional industry structure in which the utility fulfills its service obligations for all retail electricity customers, the utility is responsible for adding new, or "incremental," resources as needed to the utility's existing portfolio of generating assets, purchased power and demand-side resources. Many states with this traditional structure have chosen to issue rules or other policy guidelines that specify when and how utilities should undertake competitive procurements for acquiring incremental resources. These states include Arizona, California, Colorado, Florida, Louisiana, Montana, Oklahoma, Oregon, Utah, and Washington.

Regulators in these traditionally regulated states face a complex array of important issues in the design of effective procurements. Table 2 (at the end of the Executive Summary) lists a series of important topics that regulators must consider when guiding utilities' use of procurements and their overall design ("architecture") and implementation. This list is long, and the choices often involve important tradeoffs, as described in greater detail in this report. Table 3 (also at the end of the Executive Summary) looks at these same issues through a somewhat different lens by identifying a series of key questions for regulators to bear in mind as they consider whether and how competitive procurements are to be used by utilities in identifying incremental supplies for retail customers.

The first key issue for incremental resource procurements is the design of safeguards to prevent potential improper self-dealing by the utility.[3] Because the utility may financially benefit from the selection of its own self-build offer or a proposal from an affiliate, safeguards are necessary to ensure that the process is not improperly tilted toward the selection of such offers. As the report describes, a variety of means are available to provide such safeguards, including:

- Involvement on a third-party independent monitor ("IM") and/or independent evaluator;
- Measures to increase the transparency of the procurement process to market participants and the public;
- Providing potential bidders with detailed information needed to prepare competitive bids;
- Utility codes of conduct[4] to prohibit improper sharing of information that is valuable to utility affiliates in their construction of procurement offers and/or their competitiveness in other electricity markets; and

[3] By using the phrase, "improper self-dealing," we intend to recognize that many states that require or encourage competitive procurements for incremental supply also require – indirectly or directly – that the utility also participate in the process as one of the entities making a supply proposal. This inherently places a utility in the position of being a "competitor" as well as the entity that evaluates and selects the winning proposal. We are characterizing this situation as "proper self-dealing," in the sense that the utility has these two responsibilities, and may, through a fair and objective evaluation, select its own proposal as the winning proposal. By contrast, we use the phrase "improper self-dealing" to indicate situations where the utility acts so as to structure the procurement design, the product to be procured, and the actual evaluation and selection of the winning resource in ways that unduly favor its own proposal or any proposal offered by an affiliate.

[4] In this report, when we use "codes of conduct," we are referring to state policies that guide the character of permissible and impermissible interactions among different staff and divisions of enterprises that include utility companies. We recognize that the FERC has adopted and is considering changes to its own Standards of Conduct for Transmission Providers (see, e.g., 122 FERC ¶ 61,263, Standards of Conduct for Transmission Providers Docket No. RM07-1-000, Notice of Proposed Rulemaking, March 21, 2008).

- Careful disclosure and review of how "non-price" factors are considered and evaluated by the utility in weighing offers from third parties against self-build proposals or affiliate offers. (See further discussion, below.)

The second key issue is the appropriate evaluation of price and non-price criteria. Price criteria typically involve the proposed direct payments for any energy, capacity, environmental credits, or other attributes provided by a resource under contract to the utility. Non-price criteria include the many factors that may also affect how much energy, capacity and other attributes would eventually be supplied by different resources, and their impact on other aspects of the utility's system. Non-price factors can include such things as transmission facility impacts, fuel preferences, location preferences, power plant performance requirements, project development milestones, re-dispatch implications on other resources, credit considerations, utility balance sheet impacts, and the distribution of financial and development risks between the utility and the power provider, and/or the utility and its ratepayers.

Even when a utility does not have an affiliate offer or a self-build proposal in the mix, these non-price factors create unique challenges for evaluating offers. They often introduce complex modeling requirements and the need to weigh factors that may not lend themselves to neat quantitative metrics. Because of these inherent difficulties, use of non-price criteria requires careful regulatory oversight, particularly where the utility has – or perceives it has – a financial interest that varies depending on the outcome of the evaluation process. This oversight is facilitated in such cases through the active involvement of an IM and through other regulatory policies that alter utility incentives (such as commitment to address debt equivalency in rate case proceedings or other mechanisms).

The third issue for procurement of incremental resources is how to structure regulatory policies and practices to promote desirable and competitive supply offers in ways that also fulfill and align with other important regulatory obligations. Commissions may have discretion to decide how and when to review different parts of competitive procurements. Among the things they may directly review and approve are: the type, amount, and timing of resources to be solicited; the RFP documents (including model contracts); and evaluation criteria (including evaluation methods, data and assumptions, credit requirements, and weights among price and non-price criteria). Commissions often have to decide when to examine such things – that is, before the RFP is issued, or after the bids have been received and evaluated by the utility. Providing and clearly demonstrating regulatory support for the approaches being used in the utility's solicitations will help inspire a competitive response. So will early regulatory actions that signal that the Commission will endorse cost-recovery for the outcomes of competitive procurements designed and implemented fairly and objectively by the utility. These signals will reduce market and regulatory uncertainty faced by both utilities and third-party suppliers and will contribute positively to more competitive and less costly incremental supplies for rate payers.

Procurements for all-requirements service introduce different issues and challenges from those described above. In many of the states with retail choice and where distribution utilities now own or control few generation assets (as a result of industry restructuring in the past decade), the utility must obtain needed generation supply for those basic service customers entitled to buy bundled supply from their local utility. In many of these states, the distribution utility uses a competitive procurement process to obtain supply for full-requirements service ("FRS") customers. FRS supply is typically a standardized product and generally includes energy, capacity, ancillary services, and other electricity services needed to meet a slice of the needs of basic service customers as their demand rises and falls over the seasons of the year and the time of day, and as the number of basic service customers changes over time.

States in which utilities have used competitive procurements to elicit offers for FRS supply at some point over the past few years include Connecticut, Delaware, Illinois, Maine, Maryland, Massachusetts, New Jersey, New York, Ohio, and Pennsylvania.

Competitive procurements of FRS supply typically call for offers for the same standardized electricity product (e.g., FRS supply for residential customers). Winners can be selected solely based on the price of their offers. While the technical details of the procurements may require careful design to elicit an efficient and objective result, the "price-only" design greatly reduces other evaluation and regulatory challenges. The elimination of non-price criteria in selecting offers also reduces opportunities for improper self-dealing, which in turn greatly reduces the need to carefully design some other safeguards to protect against such problems.

States using FRS procurements nonetheless face other important challenges. In recent years, for example, regulators in some states have focused efforts on structuring the sequence of procurements to smooth out the effect of potentially volatile prices on rates charged to basic service customers. Most recently, policy makers in some states (e.g., Connecticut, Illinois, and Ohio) are beginning to shift away from sole reliance on FRS procurements, and are developing and considering "hybrid" FRS frameworks that expand or alter the utility's (or other institution's) role in providing supply for retail customers (see Table 1).

Our research indicates that there is now considerable experience in designing competitive procurements, although actual experience with procurement implementation is somewhat more limited. This is still a "work in progress." Many states are finding competitive procurements to be an essential tool for obtaining electricity supply that nonetheless introduces significant implementation challenges. The ways in which regulators and utilities address the fundamental issues and important details are critical to their success. This report aims to assist regulators in learning from the practical experience of others in using markets to procure electricity supply to help assure just and reasonable rates for retail electricity consumers.

**Table 2**

**Critical Issues in Designing Competitive Procurements for Incremental Supplies**

| **Commission Choices** | **Additional Considerations** |
|---|---|
| **Procurement Process Architecture** | |
| Form of the commission's policy: | What form and in what level of detail will the Commission's policy take: e.g., Regulations? Informal guidelines? Decisions in response to utility proposals? |
| Role of an integrated resource plan ("IRP"): | What role will an IRP play in determining the timing, amount and type of resources to be procured through a competitive solicitation? |
| Product definition: | What is the product being procured? Will it be broadly or narrowly defined? Will demand-side offers be considered? How will any policy preferences for particular types of resources (e.g., renewables) be established and implemented? |
| Procurement procedures: | What requirements will be put in place: e.g., for requests for proposals ("RFPs"), auctions, negotiations, and other design details? |
| Involvement of an independent monitor: | Under what circumstances will an independent monitor or evaluator be required? Who chooses it? What actions and responsibilities does it undertake? |
| Commission staff's role: | Will the staff directly oversee the RFP process, on-site with the utility? Will the staff assist the oversight of an independent monitor? |
| Commission approvals: | At what stage(s) of the process does the Commission carry out a formal review and/or approval? E.g., approval of the IRP? The RFP design? The bidder short-list? Winning offers? Contract approval? Will the Commission's review of the process elements as implemented allow the Commission to endorse the contracts that result from it (assuming a finding that the process produced a competitive result)? |
| Public participation: | What parts of the process should include public participation? E.g., determination of the types of resources to be procured? Review of RFP instrument and/or model contract? |
| Scheduling process elements: | How will the timing of the process be designed to balance market and regulatory requirements? |
| RFP documents: | What materials will be issued with the RFP? E.g., evaluation criteria and weights? Model contracts? Credit and collateral requirements? |
| Pricing offers: | Will the initial bids involve final offer prices or preliminary indicative offers? Will bidders be permitted to "refresh" their offers over time during the RFP? |
| **Evaluation of Offers** | |
| Evaluation methods and criteria: | How will the array of price and non-price elements (e.g., location, resource operating characteristics, development status) of the offers be evaluated? |
| Comparison of offers with different risk profiles: | How will the evaluation compare offers with different assignments of various risks (e.g., fuel price risk, fuel supply deliverability, project development, construction cost, availability, credit risk, technology risk, changes in law)? |
| Transmission impacts and costs of any transmission upgrades: | How will the transmission-related cost implications of different offers be evaluated: Through the status of interconnection requirements? The costs of needed transmission system upgrades? Congestion impacts from dispatch of the proposed offer? |
| Evaluation of system interactions of offers: | How will the evaluation of offers assess interactions with the rest of the utility's portfolio (e.g., sensitivity analyses of key assumptions, such as fuel price changes)? |
| Debt equivalency: | Will the process consider the financial impact on the utility of contracts versus rate base investment? If so, how? E.g., using an adder assigned to offers from third parties in the RFP process? As part of the review of the utility's cost of capital in rate cases? |

**Table 3**

**Key Procurement Policy Issues – A Checklist for Regulators**

| Threshold Question | Second Order Question | Observation: |
|---|---|---|
| ☑ Should the utility test the market for alternatives to building its own power plants? | ➡ If so, does the commission require (formally) the utility to carry out a competitive procurement, encourage such procurements by providing specific guidelines or recommendations, or give the utility full discretion to do so? | Clarifying commission policy toward competitive procurement and making such policy statements easy to find in PUC websites may lower barriers to entry for independent suppliers seeking to participate in the state's market; on balance, this may serve to support a deeper response to any solicitations. |
| ☑ What is the "product" that the utility should procure through competitive solicitations? | ➡ Is the procurement designed to solicit narrowly or broadly defined products? That is, should the procurement solicit offers for any type of resources to meet given power supply needs, or limit offers to:<br>o Supply-side resources?<br>o Resources using a particular technology (e.g., renewables) or particular fuel (e.g., coal)?<br>o Resources providing a particular function in a supply portfolio (e.g., baseload v. peaking)?<br>o Capacity resources?<br>o Resources in a particular zone?<br>o Resources from new facilities?<br>o Products satisfying particular regulatory requirements (e.g., renewable energy credits)? | Procurements with more narrowly defined products will allow greater reliance on price and less reliance on other evaluative criteria, although it may limit the depth of the market response and the creativity of offers from market participants.<br>The greater control the commission wishes to exert over the choice of attributes of the product being solicited (e.g., type of resource, location, fuel or technology type, function in the portfolio), the more the commission will likely need to encourage review of formal (or informal) utility long-range resource plans in advance of the resource procurement. |
| ☑ Does the commission want to allow – or require – the utility to participate in the solicitation, either directly as a supplier proposing a resource relying upon regulated investment, or indirectly through a competitive affiliate? | ➡ If so, what safeguards will the commission establish and enforce in order to prevent improper self-dealing to assure a fair and competitive solicitation, increase the opportunity for the best resource to be selected, and assure the market that there will be no improper preferential treatment of utility or affiliate offers (thus instilling confidence in the overall design of the competitive procurement)?<br>➡ Whether or not the utility is allowed to or does participate in the solicitation, how will the commission ensure that the utility's evaluation is focused on decisions supporting lowest-cost, reliable service to customers, even where different resource choices may have different impacts on the utility's own real or perceived financial interests? For example,<br>o Implications for the utility's risk profile, capital costs, balance sheet, and so forth, associated with of a third-party contract versus investment a utility owned plant?<br>o Implications for the performance of the utility's own plants (e.g., implications for stranded investment) from transmission congestion due to new resource additions?<br>➡ What guidance will the commission provide to the utility and to market participants about how various risks should be assigned in contracts between:<br>o The utility (as buyer) and a third party supplier, and in turn between the utility and its retail customers;<br>o The utility as a power plant owner and its customers. | Putting in place appropriate safeguards to ensure that the utility's decisions are made with the interests of customer benefits and costs in mind involves great care in the overall design, implementation and supervision of the procurement. Key safeguards to guard against improper self-dealing include:<br>▪ Use of an independent monitor throughout all phases of the process;<br>▪ Commission review of product definition, evaluation assumptions and techniques, contract terms and conditions, debt-equivalency issues in rate cases (not RFPs) and other elements to support fairness for market participants;<br>▪ Requiring comparable forms of risk mitigation in utility and non-utility offers, such as comparable treatment of offer "refreshing" and various types of risk, including development and construction risk, power plant performance risk, fuel price risk, and risks tied to changes in law or regulation, such as costs of mitigating carbon emissions. |

**Table 3 (Continued)**

| Threshold Question | Second Order Question | Observation: |
|---|---|---|
| ☑ To what extent will winning resources be selected on price terms and non-price characteristics, some of which may be difficult to quantify and compare? | ➨ How will the commission's policies shape how and what types of non-price characteristics should be considered by the utility in evaluating offers, in light of such criteria as:<br>o The potential differences in the importance of various non-price characteristics in alternative offers;<br>o The potential for evaluation of non-price characteristics to impose high administrative costs or slow evaluation procedures;<br>o The potential introduction of subjectivity (with the opportunity for self-dealing) that non-price characteristics may create?<br>➨ If non-price factors are necessary to the selection of "best" resources, how will the commission encourage a process that provides sufficient information to the market (e.g., what factors matter, what weight will be assigned to them, and how they will be measured) without also limiting the utility's flexibility to use qualitative judgment in evaluating offers? For example,<br>o Where the winning offers will become part of the utility's resource mix and have network service, how will the need for transmission additions be evaluated, particularly if impacts differ substantially among offers and take time and other resources to fully evaluate?<br>o How will the utility take into account the development status (e.g., types of permits in hand, construction completed) of resource options in ways that support competitive responses while fully accounting for significant differences in risks to consumers?<br>o How will the process incorporate any non-price factors that are relatively easy to put into dollar terms (e.g., transmission enhancement costs), and those (such as project development risk) which are harder to monetize? | The more transparent the evaluation procedures and criteria are to market participants, the more likely they will be assured that the evaluation process will be fair and objective. At the same time, the more the choice of "best resource" depends upon each offer's interaction with the rest of the utility's portfolio, the more the selection will depend upon complex modeling of the utility's portfolio; reliance on these models raises traditional transparency issues associated with "black box" modeling. As a result, regulators will need to pay attention to the modeling assumptions and inputs used by the utility in evaluating resource options (including sensitivity analyses) to help ensure a competitive result. Such review is particularly important where the utility (directly or indirectly) has a financial interest in the outcome of the results (e.g., either directly, if proposing a competing project, or more indirectly, if it owns another existing plant that may become less valuable depending on facility selection). |
| ☑ If you have committed to having your regulated utilities use competitive procurement processes, are you willing to align your own regulatory practices to support them? | ➨ Assuming that markets assign risk to uncertain regulatory outcomes, how will the commission arrange – and commit to implementing and enforcing – its own actions to support outcomes that appropriately balance risks between suppliers, the utility and ratepayers? Relevant regulatory risks that can show up in price premiums include:<br>o Uncertainty about cost-recovery for utilities' contracts with power suppliers versus the utility's own investment;<br>o Uncertainty about how long contract approval will take;<br>o Uncertainty about whether the regulator will enforce the rules requiring fairness and objective processes;<br>o Uncertainty about whether the commission will reopen the process – or throw out the results – if it doesn't like the particular outcome of a solicitation; and<br>o Uncertainty about whether the regulator will allow the utility to take actions that circumvent the procurement, alter procurement procedures mid-stream, or dissolve the procurement (irrespective of rationale)? | The higher the market's confidence that the regulatory agency will support its own past policies and decisions, the lower the risk premium that will be built into offers from the market. Past commission policies and decisions may include meeting certain procedural time requirements to which it has committed and enforcing as appropriate any procurement rules previously adopted. |

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# I. INTRODUCTION AND BACKGROUND

Competitive procurements are not new to the electric industry. Over the past two decades, regulators and the electric distribution utilities ("utilities"[5]) they supervise have experimented with various forms of competitive process as a way to assure lowest-cost, reliable supply for retail electricity customers. In response, the industry has grown to include a wide array of competitive suppliers interested in and capable of providing utilities with power supplies to meet retail customers needs.

Despite this long experience, the use and regulation of competitive procurements has undergone important changes in recent years. Today, many states require[6] – directly or indirectly – that their utilities use competitive procurements as a means of obtaining supplies to serve their retail customers. All told, more than 40 percent of the U.S. states (or jurisdictions)[7] have formal regulations or guidance that requires or encourages utilities to use competitive processes.

In some states with restructured electric industries where the utility no longer owns or controls its own generating resources, utilities are required to procure all of their supply for retail customer's power through competitive processes. Many states with a more traditional industry structure require or at least encourage their utilities to test the market to determine what new source of supply offers the "best" option for meeting incremental customer requirements. In such procurements, the utility's own investment in a new generating resource may compete against offers from third-party power suppliers or the utility's own affiliate. While competitive procurement processes are not new, states in recent years have increased requirements on utilities for when and how such procurements must be undertaken.

With this growing interest in the design and use of competitive procurements, the members of the National Association of Regulatory Utility Commissioners ("NARUC"), through its Committee on Electricity, have been engaged in a collaborative dialogue with the Federal Energy Regulatory Commission ("FERC") on issues related to competitive

[5] Unless otherwise stated, we use the term "utility" to refer to the local distribution utility with certain obligations to serve retail electricity customers.

[6] We note that our use of the word "require" may encompass directives that are a part of non-binding, legislative or commission "guidelines".

[7] States or jurisdictions with formal rules or guidance include Arizona, California, Colorado, Connecticut, Delaware, the District of Columbia, Florida, Illinois, Maine, Maryland, Massachusetts, Montana, New Jersey, New York, Ohio, Oklahoma, Oregon, Pennsylvania, Utah, and Washington. Some other states, such as North Carolina, have less-formal policies and/or have case precedent directing utilities to have tested the market if they propose to build a new generating station.

power procurement. As part of this collaborative dialogue, NARUC engaged Analysis Group[8] to perform a study of competitive procurement of retail electric supply.[9]

This report provides the findings from our study. In the sections below, we:

- Identify key state policy and technical issues associated with current competitive procurement practices;
- Develop criteria for evaluating the success of procurement policies and practices;
- Evaluate current state procurement policies and practices against such criteria;
- Develop guidance on and tradeoffs between "model" competitive procurement practices that are appropriate in different contexts that reflect these criteria; and
- Where possible, identify best practices in procurement design and implementation.

Our findings are intended to provide guidance for states as they determine the appropriate role of and regulations affecting competitive procurements. We do not include any specific recommendations for what any individual state should do with respect to competitive procurements.

To accomplish these goals, we have collected and assembled information on the design and implementation of utility supply procurements. We have researched current state policies that influence whether and how these procurements occur. This information provides many examples of policy designs and practical experiences that have taken shape over many years under different regulatory traditions and industry settings. An important part of our information collection was a survey of state utility commissions that requested detailed information about competitive procurements. Responses to that survey, along with our own research and information collection, identified many key relevant documents, including:

- State legislation;
- Commission orders related to general procurement policy and to individual utility procurements;
- Utility request for proposals ("RFPs");
- Independent monitor ("IM") reports;

[8] The study has been conducted by Analysis Group's team: Susan Tierney, Ph.D., Managing Principal; Todd Schatzki, Ph.D., Manager; Andrea Okie, Associate; Pavel Gavrilov, Senior Analyst; and Mary DiMatteo, Analyst.

[9] NARUC, "Request for Proposal to Identify Model State and Utility Practices for Competitive Procurement of Retail Electric Supply," Proposal Number 000-07-01, September 26, 2007.

- Regulatory filings by various stakeholders (including electricity suppliers); and
- Other relevant documents.

The body of documents we have collected through this process is available electronically for access by the public.[10]

Our review focuses primarily upon activities in states that have formal requirements or guidelines for competitive procurements.[11] Specifically, we do not review the relevant competitive procurement policies or practices of publicly-owned utilities (e.g., municipally owned utilities and cooperatives), small investor-owned utilities, or unregulated competitive retail suppliers in states with retail competition (e.g., Texas). Additionally there are a number of other things which we explicitly did not study, based on our understanding of the original scope of work from NARUC.[12] Notably, our analysis is confined to a review of competitive procurements as regulated by state public utility commissions.[13]

[10] Documents are available at: <http://procurement.webexworkspace.com/>. Members of the public may access these documents by registering as a "guest" at this website.

[11] Many utilities in states without formal policies on procurement may undertake competitive procurements as a part of, for example, demonstrations that certain resources (such as those, for which the utility is seeking certification and cost recovery), are least-cost.

[12] We do not make recommendations about whether states should or should not rely on competitive procurements. Nor do we prescribe a "correct" approach to be adopted across all states that decide to use competitive procurements. We believe that this is entirely a matter of state policy preference, and in some cases, legislative authority. Also, because use of competitive procurements and their design involves a number of important trade-offs that affect how risks are assigned between utilities and their customers, on the one hand, and utilities and their suppliers, on the other, we do not conclude that one or another trade-off is right or wrong. In some cases, we attempt to elucidate implications of trade-offs between particular approaches. We refrain from critiquing particular states' approaches by name; instead, we focus on issues in procurements that are relevant for states in designing or refining competitive approaches in their states. We do not specifically cover competitive procurement practices in prior periods that are no longer being used in states (e.g., for PURPA implementation). We do not focus on competitive procurement for supplies of relatively short-term length (e.g., less than one year). We do not focus on policy the details for states with open dockets on whether to modify their current approaches to procurements. And, in situations where prior problems have been addressed in subsequent policy or other regulatory decisions, we have not dwelt on the prior problems.

[13] As requested in the original scope of work, we do not directly review the relationship between: (a) states' policies for competitive procurements and the practices of their distribution utilities, and (b) other policies of the FERC, the states or regional entities throughout the United States.

## II. OVERVIEW OF STATE COMPETITIVE PROCUREMENTS

While utility competitive procurement practices vary in many important details across the states, certain common frameworks have arisen. Table 4 describes some of these patterns. It shows, in the middle column, that utilities generally utilize one of two types of procurement frameworks: (a) procurement of "incremental supply," or (b) procurement of "supply for full-requirements service." The common approaches result primarily from patterns of regulatory and market conditions that have influenced the types of resources, or electricity products, that regulated distribution utilities need to procure. Table 4 shows different circumstances under which utilities are required (or strongly encouraged) to make use of competitive procurement processes to obtain power supplies for their retail customers.

**Table 4**

**Frameworks for Procurement of Electricity Supply for Retail Customers**

| Electric Industry Structure | Divestiture of Power Plants | Procurement Framework / Product Solicited | Supply Portfolio Management | State Examples |
|---|---|---|---|---|
| Traditional | None | Incremental Supply – typically for resources from a specific power plant obtained through requests for proposals ("RFPs") | Utility | CO, GA, LA, OK |
| Restructured, No Retail Choice | None or Partial | Incremental Supply (via RFP) | Utility | CA, MT |
| Restructured, Retail Choice | Full (or near full) | Full Requirements Service ("FRS") (via auctions or RFPs) | Market | MA, MD, ME, NJ |
| | | Hybrid FRS Frameworks:<br>• Long-term contracts (with FRS procurement)<br>• Utility ownership of generation, with some degree of portfolio management by the utility<br>• Public power authority<br>• Specialized procurements (e.g., renewables or renewable energy credits) | Variously Assigned to Market and to Utility | CT, DE, IL, OH, PA |

In a procurement for "incremental supply," a utility seeks to add a new supply source to its existing portfolio of supply arrangements. This existing portfolio generally includes significant ownership (or control) of generation facilities, but may also include purchase power agreements (short-term or long-term), financial hedges, demand-management, and other forms of resources and supply commitments. This type of procurement is the typical approach used in states with a traditional industry structure, where the utility has the obligation to serve retail customers in its franchise area.

Some traditionally structured states (such as Colorado, Georgia, Louisiana, and Oklahoma) have adopted relatively explicit regulations or formal guidance addressing when and how utilities are to use competitive procurements as part of identifying their next resource additions. Other state commissions do not have codified procurement regulations, per se. Some, such as North Carolina, have issued various decisions in the past that have the effect of imposing a presumption that utilities will "test the market" for attractive resource offers at least as a means of demonstrating that their plans (including any proposals to build their own power plants) are economical. Other traditionally structured states do not have policies related to utilities' use of competitive procurements.

Incremental supply procurements are also used in some states (like California and Montana) where utilities divested much of their generating assets under electric industry restructuring, but where retail competition has been suspended. Utilities in these states, as well as in Arizona, currently use incremental procurements to meet resource needs above and beyond the supplies provided by long-term contracts and/or their remaining generating resources.

The other type of procurement is for supply for "full requirements service" (or, a "FRS" procurement). This type is used mostly in states where: (a) retail customers have the right to choose their electricity supplier, (b) distribution utilities have divested all or nearly all of their generation assets as part of electric industry restructuring, and (c) the utility still retains obligations to serve basic service (or default service) customers. Under FRS procurements, the distribution utility obtains all (or most) electricity supply for its basic-service customers (or a particular class of customers). Because these utilities lack their own generation resources but still retain certain service obligations to customers, the utilities' competitive procurements essentially shift much of the responsibility for assembling and managing an array of electricity services to suppliers who are willing to provide needed electricity services for these retail customers.[14]

In a few states with retail competition (e.g., New York, New Hampshire), utilities retain portfolio management responsibilities and functions for basic service customers, similar to the way in which vertically integrated utilities manage a portfolio of assets in states without retail competition. The portfolio of assets managed by these utilities may include generation facility ownership, long-term supply contracts, financial hedges, spot market purchases, and other agreements.[15] While state commissions typically oversee these portfolios for purposes of cost recovery, regulators generally do not direct or

[14] In Maine, electric distribution utilities are not involved in the procurement of supply for FRS customers. Instead, FRS procurements are run by the Maine Public Utility Commission, and winning bidders become the retail providers for customers.

[15] For example, certain utilities in New York and New Hampshire manage supply portfolios, which may include long-term contracts arising from industry restructuring. Utilities recover the costs of these portfolios through rates approved by regulators. Competitive retail providers also generally rely on development of supply portfolios to supply power for their customers. The amount of supply provided through such retail providers varies from state -to -state. In Texas, where there is no "standard offer" service provider, all retail providers procure supply through these unregulated portfolios.

investigate the specific resources utilities arrange as part of the individual components of these portfolios.[16]

In recent years, some states have introduced or are considering adopting policies that create a hybrid framework, in which utilities (or other regulated entities) may consider developing certain types of long-term supply arrangements in addition to the on-going use of FRS contracts for its retail customers. These modifications include requirements (or incentives) for utilities to enter into long-run supply contracts (e.g., New York), utility development and/or ownership of generation facilities (e.g., in Connecticut, Ohio), and development of state power authorities (e.g., in Illinois).[17]

Incremental supply procurements and FRS procurements differ in an important, fundamental way. FRS supply procurements are typically designed as price-only procurements, in which the utility requests bids to supply a uniform product using a standard contract. By standardizing product specifications and contract terms, price is the only factor differentiating alternative offers and suppliers offering the lowest prices are selected as the winning bidders. In contrast, offers submitted in response to incremental supply procurements differ along multiple dimensions, including price and non-price factors. To select the "best" offer, the utility not only must evaluate and compare each offer's unique attributes, but must also evaluate how each possible new resource would interact with the rest of the utility's overall supply portfolio. This significantly complicates the evaluation and selection process.

As a result of these procurement characteristics, price-only auctions for FRS supply are similar to on-line shopping for a mass market product (such as a specific book or a particular toy) that a consumer has already decided to purchase.[18] In contrast, incremental supply procurements are more akin to buying a house, because no two houses are alike and the choice among houses requires comparison of the many different attributes that differ between houses. Because of this fundamental difference in these two approaches, we discuss each of these approaches separately below. Before doing so, though, we describe various criteria to use in evaluating procurement processes.

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[16] Our assessment does not focus on the development of these portfolios, although lessons from incremental supply procurements may provide some guidance for best practices for and oversight of procurement of individual components of such portfolios.

[17] Additionally, Massachusetts has just passed a law (the Green Communities Act, signed on July 2, 2008) that will require utilities to rely on all cost-effective energy efficiency and allow utilities to enter into certain long-term contracts for renewable energy, while also retaining the basic FRS framework.

[18] Bidder eligibility requirements are also similar to the types of minimum standards for merchant quality (e.g., merchant ratings) that people use when considering on-line purchases.

## III. CRITERIA FOR THE EVALUATION OF COMPETITIVE PROCUREMENTS

In the end, the goal of using competitive procurements is to enhance the process of identifying and securing resources that "best" meet customers' electricity requirements on the "best" possible terms. With this is mind, we describe the types of criteria that help to distinguish well-designed versus poorly designed competitive procurement processes. We offer five key criteria (listed in Table 5). While each is important and seemingly obvious, together they can pose difficult trade-offs as regulators and utilities design procurements to fit the needs of particular situations. Any commission that decides to rely on competitive procurement processes should use criteria similar to these to guide the design and implementation of such procurements.

**Table 5**

**Criteria for evaluating competitive procurements for retail supply:**

Where regulators have committed to relying upon competitive procurement approaches as a means to help identify the "best" resources needed to meet the needs of the utility's customers, the process should have and be viewed as being:

- Fair and objective;
- Encouraging of a robust competitive response and creative proposals from market participants;
- Based on appropriate and relevant evaluation of price and non-price factors;
- Efficient and timely in offer selection;
- Positively supported by regulatory actions that reinforce the commission's commitment to the other criteria.

- **The procurement process should be fair and objective.** A fair and objective process will help to ensure that the outcome of a procurement "best" satisfies retail customers' supply requirements and does not reflect any undue preferential treatment of particular bidders. Such a process also promotes participation by assuring market participants that their offers will be fairly considered on their merits. To achieve this goal, procurements must include appropriate safeguards built into the design of the procurement to prevent undue preferential treatment of any offers. These safeguards must be supported through the practical elements of the implementation phase so that unforeseen circumstances are addressed in manner that is fair and consistent with a competitive outcome. The fairness and integrity of a procurement process is affected not only by the actions of the utility, but also by regulatory oversight of the procurement process. If a commission decides to rely on competitive processes, it own actions to enforce fundamental fairness objectives and uphold any prior commitments to use markets are a critical component of the process of identifying the "best" retail supply for utility customers.

- **The procurement should be designed to encourage a robust competitive response and creative offerings from market participants.** In developing a competitive procurement, the regulators' goal is to design and carry out a process in which suppliers of the most cost-effective resources not only participate but also submit their most competitive offers. Several conditions are key to encouraging such participation. First, market participants must perceive that their offers will be considered fairly and objectively. Concerns about preferential treatment will lower market participants' willingness to incur the up-front costs necessary to submit offers. Second, procurements must protect confidential and commercially sensitive information submitted by market participants. Third, market participants must have access to adequate information about bidder requirements, product specifications, model contract terms, evaluation and selection procedures and criteria, and other factors that would affect the resources they choose to offer. Finally, procurements should allow sufficient creativity to solicit the best offer for customers.

- **The procurement should select winning offers based on appropriate evaluation of all relevant price and non-price factors.** Selecting the "best" offer(s) requires first identifying appropriate evaluation criteria and then evaluating the offers objectively against them. Designing an effective evaluation process is inherently challenging when such evaluations require comparisons of an array of price and non-price factors. In particular, many of these non-price factors are quite complex to quantify and/or qualitative in nature. By contrast, procuring products that meet standardized specifications (such as full requirements service for standard-offer-service customers) greatly simplifies the evaluation process by allowing for the selection of winning offers based on price terms alone. Identifying evaluation criteria that reflect the attributes of greatest importance will increases the likelihood of eliciting offers that best suit retail customers' supply needs.

- **The procurement should be conducted in an efficient and timely manner.** Competitive procurements should avoid unnecessary administrative and procedural costs that may discourage market participants and ultimately impose greater costs on ratepayers. Because bidders are generally required to honor the terms of their offers once made, an unnecessarily slow process increases the financial risks they face from unanticipated changes in market conditions that occur while their offers are "open." Design of bid submission requirements, evaluation and selection procedures, and the timing of commission review should aim to minimize transaction costs for utilities and/or bidders (and the price premiums they include in their bids).

- **When using a competitive procurement process, regulators should align their own procedures and actions to support the development of a competitive response.** Regulators' own actions can positively – and in some cases, negatively – affect the integrity and outcomes of a procurement process. Positive signals can arise, for example, by doing what is legally possible to protect the confidentiality of commercially sensitive information submitted through supply offers, by conducting regulatory reviews in a time frame that supports the "best" price terms in offers, and enforcing elements of the procurement design that enhance the overall fairness and objectivity of the process and the integrity of the procurement results.

As may be evident, there are potentially important interrelationships among these criteria. Establishing a fair and objective process provides suppliers with confidence that their up-front investment in submitting bids is worth the effort. A fair and objective process will provide regulators with greater confidence that procurements will result in just and reasonable rates, thereby allowing them to provide greater assurance of cost recovery of winning proposals. All else equal, regulators' actions to support the integrity of a competitive process will provide confidence that the process will be fair and objective; this in turn will increase the likelihood that there will be a competitive response from the market and that the winner of the process will be the "best" resource for customers.

# VI. PROCUREMENT OF INCREMENTAL RESOURCES

## A. OVERVIEW

Incremental resource procurements are used by electric distribution utilities to obtain new resources to add to their existing portfolio of assets, supply contracts and demand-side programs to meet the utility's service obligations to its retail customers. This type of procurement is the basic form relied upon in states with more traditional electric industry structures where the state requires a market test for new resources. In addition, incremental resource procurements are used in states with retail competition where distribution utilities are procuring long-term resources in addition to FRS supplies (e.g., Connecticut) or where utilities serve their basic-service offer customers using a portfolio of resources they manage (e.g., New York).

In states with a more traditional industry structure, utilities provide bundled electricity service as the sole option for retail customers. The utility has the responsibility to manage a resource portfolio, which typically[19] includes large amounts of generation assets under its ownership, but may also include short- and long-term purchase power agreements, demand-management resources, and other forms of financial hedges and supplies. The extent to which these utilities actually use competitive procurements when seeking to identify and secure the next new resource(s) to add to the resource portfolio varies across and within states.

The design of these incremental supply procurements is shaped by several key factors. First, the array of potential resources available to fill a utility's incremental needs varies along many dimensions. Among others, key differences include:

- the physical characteristics of the resources used to provide supply (e.g., location; technology type; fuel type; availability factors; start-up, ramp rates and cycling features; maintenance requirements);
- operational commitments (e.g., dispatchability or non-dispatchability; provision of energy, capacity, ancillary services, or environmental attributes; plant operation, management and fuel provision by the utility under a "tolling agreement"); and
- development status (e.g., site control; environmental permits; interconnection studies; financing; construction).

Offers also differ in the contract structure that will define the:

[19] Note that we previously described that our report focuses on investor-owned electric utilities; specifically, we do not review the competitive procurement policies or practices of publicly owned utilities (e.g., municipally owned utilities and cooperatives), small investor-owned utilities, or unregulated competitive retail suppliers in states with retail competition (e.g., Texas).

- structure of payments (e.g., all-in prices versus separate payments for such things as energy, capacity, ancillary services; fixed prices versus indexed prices; allowances for payment adders in the event of changed circumstances; penalties and bonuses for certain performance targets (such as delay in meeting development milestones or availability targets);

- the service provided (e.g., energy; capacity; unit dispatch control, in which the utility has control over when the resource delivers power; tolling agreements, in which the utility operates and manages the plant and controls the fuel supply as well; extra compensation for "regulation" service, allowing the output of the plant to be controlled by the system control area operator or system dispatcher; provision of "environmental attributes" such as renewable credits);

- supplier obligations, such as purchase requirements (e.g., minimum quantities of energy over a specified time period, or take-or-pay provisions) and fuel cost requirements (e.g., e.g., tolling agreements in which the utility provides the fuel, or the supplier has responsibility for fuel); and

- the resulting allocation of risks borne by suppliers and utilities.

Assessing the implications of these various contract structures is inherently complex due to an array of important technical details. How a specific power purchase agreement ("PPA") associated with an RFP addresses many of these details has important implications for the types and prices of offers submitted in response to an RFP. If these technical issues and risk allocations are different than those that would arise in a utility self-build proposal, then there will be difficult apples-to-oranges comparison of the offers. That said, a utility self-build proposal could be designed to reflect comparable contract terms (e.g., through price, schedule and other performance conditions as might be contained in a utility contract for engineering, procurement, and construction services (i.e., an "EPC" contract). For these reasons, model contract terms matter, in ways that warrant careful attention by regulators.

While it is possible to design a procurement to elicit offers for comparable products through detailed specification of fuel, technology type, project size, and contract terms, many procurements are designed to leave such important details to the discretion of bidders. As a result, procurements typically involve both price and non-price factors which introduce complexity into comparisons between offers.[20] This complexity makes it challenging, to say the least, to design and implement an overall competitive procurement architecture and the details of its evaluation process in ways that: (a) treat all offers fairly and objectively, (b) arrive at selections efficiently and rigorously, (c) provide enough transparency to be credible without revealing commercially sensitive

[20] Even when there are clear metrics relating to the price terms for an offer, there are often "non-price" issues (both monetized and non-monetized) associated with, among other things, how a proposed resource interacts with the rest of the utility's portfolio in a simulated dispatch and how risks are assigned to the buyer and seller.

business information, and (d) allow the utility sufficient flexibility to respond to potentially innovative and creative solutions from the marketplace. This complexity means that commissions that commit to rely on competitive procurements must be sensitive to these trade-offs.

Second, and perhaps because of the complexity of these trade-offs, incremental resource procurements that include utility self-build (and rate-based) proposals and/or proposals from the utility's affiliates inevitably pose special regulatory challenges to assure that the process is designed and implemented to be fair and objective. Because the utility's (and/or its parent's) financial interests may not be aligned with those of its customers when the utility selects from among the options, extra care is needed to prevent improper self-dealing by the utility. Best practices under these circumstances require a higher degree of regulatory supervision and scrutiny, such as the use of an independent monitor tasked to be the eyes and ears of the regulator and to help bolster the procurement's fundamental fairness and objectivity.

By using the phrase, "improper self-dealing," we intend to recognize that many states that require or encourage competitive procurements for incremental supply also require – indirectly or directly – that the utility participate in the process as one of the entities making a supply proposal. This inherently places a utility in the position of being a "competitor" as well as the entity who determines the "winning proposal." We are characterizing this situation as "proper self-dealing," in the sense that the utility has these two responsibilities, and may, through a fair and objective evaluation, select its own proposal as the "winning proposal." By contrast, we use the phrase "improper self-dealing" to indicate situations where the utility acts so as to structure the procurement design, the product to be procured, and the actual selection of the winning resource in ways that unduly favor its own proposal or any proposal offered by an affiliate of the utility.

Finally, when designing procurement processes to account for both the complexity of evaluating alternative offers and the need for regulatory oversight, it is important to make such choices in light of two other factors involving administrative efficiency. First, it is important to keep the costs to administer procurements relatively low for the bidders and the utility. Second, all else equal, it is important to minimize the time between the submission of offers, development of short-lists of preferred offers, and final selections. Because bidders may be constrained from offering their resources into other markets while their offers are being considered and they may need to maintain firm price terms in spite of market changes, delays in these evaluation stages can increase bidder's opportunity costs to participating in the procurement.

The following sections provide further details on how states and utilities active in competitive solicitations have managed these various trade-offs in the design and implementation of competitive procurements. Our assessment starts with a review of recent policies addressing procurement design, then describes the key components in procurement process architecture, and finally provides a more detailed discussion of key issues relating to the procedures and methods for evaluating offers.

## B. RECENT STATE POLICIES ADDRESSING DESIGN OF COMPETITIVE PROCUREMENTS

In recent years, legislatures and regulators in many states have taken steps to either require or amend requirements for when and how utilities should undertake competitive procurements when satisfying resource needs. Table 6 below lists some of these recent policy actions. The recent spate of legislative and regulatory changes suggests that requirements and guidelines for incremental resource procurements may continue to evolve in coming years. Therefore, regulators, utilities and market participants interested in following the progress of such procurement experience will need to continue to track relevant changes. That said, actual procurements tend to occur relatively infrequently, so the evolution may occur at a relatively measured pace.

## C. PROCUREMENT PROCESS ARCHITECTURE

### 1. Introduction to Procurement Design

When designing an overall procurement process to be used by utilities in their state, regulators must consider a number of design ("architecture") elements. Specifically, the elements should address not only the procurement criteria previously identified in Section III, but also a number of practical issues. These practical issues include such things as the responsibilities of different parties, the rules governing communications between various parties, and the materials and information that must be developed and made available to various parties. Designing such an overall procurement framework addressing all of these elements involves a number of important tradeoffs.

First, the process must be designed to ensure that winning bids are chosen based on a fair and objective process. In particular, the process must be structured to avoid improper self-dealing should the utility or its unregulated affiliates be required or allowed to offer a proposal in the procurement. Many elements of the overall design of the procurement process can mitigate the utility's ability to improperly bias the outcome of a procurement. These include:

- Commission review of RFP instruments (including what electricity supply products should be procured) and oversight of RFP procedures;
- Codes of conduct regarding interactions between utility personnel involved in evaluating offers and (a) personnel involved with developing cost projections and other elements associated with the utility's self-build proposal, and (b) any personnel of its unregulated generation affiliate;
- Engagement of an independent monitor ("IM") with reporting responsibilities to the regulatory commission and a clear scope of work with regard to procurement design, implementation, oversight, and reporting;

- Public participation in procurement design, and in commenting on draft RFP instruments, including key evaluation assumptions and model contract terms;
- Information requirements for RFP instruments (e.g., product specification, evaluation criteria, etc.), and reporting of evaluation process and results; and
- Means to control various utility personnel's access to bidders' commercially sensitive information, including information shared by utility senior managers with responsibility for both self-build offers and procurements from the market.

**Table 6**

**Recent Changes in State Policy Requirements Involving Competitive Procurements for Incremental Resources**

| State | Date | Docket Name | Description |
|---|---|---|---|
| AZ | 2007 | Recommended Best Practices for Procurement (ACC Decision No. 70032) | Commission adoption of "Best Practices" for procurements that identify acceptable procurement methods, and circumstances when RFPs and independent monitor should be used [1] |
| CA | 2003 - present | Energy Action Plan, PUC Decision 04-01-050, AB57 and various other rulings | A series of legislative and commission decisions have established procedures by which utilities develop long-term procurement plans and implement resource procurements. |
| FL | 2002 | Rule 25-22.082 Amended | Amendment to rules requiring competitive procurements for approval of utility self-build proposals, including procedures regarding bid-refreshing and information requirements regarding the self-build offer and evaluation process. |
| GA | 2004 | Amendment to Georgia Code 515-3-4-.04 Identification of Capacity Resources | Georgia General Assembly revision to the IRP Act, to include competitive procurement rules, including requirements for independent monitors |
| LA | 2004 | Market Based Mechanism Order (General Order, Docket No. R-26172 Sub Docket A) | Requirement that utilities use an RFP process to acquire and justify new resource acquisitions, including requirements for independent monitors and providing information to the public in advance of procurements |
| OK | 2007 | Title OCC, Subchapter 35: Electric Utilities – Amendments, Competitive Procurements | Specific requirements for competitive procurements necessary for filling new resource needs, including use of independent monitors and requirements related to affiliate bids and evaluation processes |
| OR | 2006 | PUC Order No. 06-446 | Update of prior order providing guidelines for competitive procurements, including 13 guidelines for RFP design, bid evaluation and selection, role of an independent evaluator, treatment of self-build and affiliate offers, and other elements |
| UT | 2005 | Utah Energy Resource Procurement Act Statute (Title 54, Chapter 17) | Requirements for procurement process for new energy resources, including requirements for an independent monitor |
| | 2007 | Rules R746-420, R746-430, R746-440 | Rules refining requirements for competitive procurements mandated in Title 54, Chapter 17 (2005) |
| WA | 2003 | General Order No. R-509 | Requirements that utilities solicit supply offers, including: specifications for RFP contents, bid ranking, and contracts; bidder option to request an independent monitor to assist commission review if the utility or its affiliates participate as bidders. |

[1] A formal rulemaking process has not been undertaken. Some investor-owned utilities are subject to specific procurement requirements arising from restructuring settlement agreement.

These approaches may limit opportunities for improper self-dealing by (a) establishing clear standards for procurement design and implementation to which utilities will be held accountable, and (b) making procurement development and evaluation transparent to regulators and market participants (as appropriate for each), so that improper conduct is easily observed.

Second, the process must be designed to encourage a competitive response from the market. Doing so will increase the likelihood that all suppliers with potentially valuable resources will participate in the procurement process, and will submit their most competitive offers. Ensuring a fair and objective process will encourage supplier participation by giving potential market participants confidence that their offers will be considered fairly against all other offers including any submitted by the utility or its affiliates. In order to submit offers that best reflect the utility's needs and system conditions, potential bidders need access to accurate and sufficiently comprehensive information on product specifications, model contract terms, credit and collateral requirements, relevant transmission constraints, costs to integrate generators into the transmission system, evaluation criteria, and other relevant factors. In addition, suppliers need to have a means of requesting supplemental information or clarifying information in ways open to all other competitors. However, while aiming for transparency of and access to information, utilities must also balance the need for confidentiality of certain supplier and utility information.

Finally, procurements must be designed to be efficient and timely, consistent with both the utility's own needs as well as those of market participants. The need to keep processes efficient yet thorough and fair creates tradeoffs in procurement design. For example, utilities should balance the cost of information requirements on suppliers with the need to obtain sufficient information to ensure that bidders offer suitable proposals. Similarly, streamlining regulatory reviews can help avoid creating time-consuming delays that may increase risk premiums that market participants build into their offers. With that in mind, it is helpful for regulators to review various early elements of procurement design (such as RFP instruments, evaluation approaches, and model contracts) prior to the utility issuing a final RFP as a means of limiting the extent of regulatory reviews in later procurement stages (e.g., review of final selections or final contracts). Reducing such delays will help to support the eventual procurement of the best resources from consumers' standpoint.

Although there are differences in particular procurement designs, most incremental resource procurements involve the following basic components, in which the utility:

- Identifies needed resources (such as through a long-range resource planning process);
- Designs an RFP instrument to solicit offers to provide needed resources, including potential public participation through comments on the draft instrument (including its anticipated evaluation process, and model contract terms and conditions);
- Receives bids in response to a final RFP from interested suppliers;

- Evaluates all offers and selects a winning offer, in either a single phase or multiple stage process (e.g., pre-qualification of bidders before issuing the RFP; or a review process to develop a short-list of the best set of offers);

- Informs bidders and regulators of resource selections;

- Enters into contract negotiations with the final award group; and

- Submits the results of the process (e.g., the award group with winning contracts) to the Commission for approval.

Box 1 illustrates these stages and other aspects of a specific procurement through a summary description of the competitive procurement process in Georgia.

**Box 1**

**Incremental Supply Procurement Process in Georgia**

In 2004, the Georgia General Assembly passed new rules requiring utilities to obtain incremental supply-side resources through an RFP process that includes use of an Independent Evaluator, application of utility codes of conduct, and various specific requirements for RFP content and public participation.[a] Georgia Power has procured a wide range of resources under these new rules, including: baseload and intermediate resources for a particular location (i.e., Northeast Georgia); baseload resources of varying potential terms (e.g., for 7-, 15- and 30-year periods); and long-term supply-side resources starting in 2016 (for which Georgia Power is offering a self-build nuclear facility). Georgia Power and its affiliates have been allowed to participate in these procurements.

In Georgia, RFP documents go through a public comment period that includes: issuance of a draft RFP; the utility's response to public comments on the draft RFP; public access to all drafts and comments through a public web site; and hosting of bidder conferences. Georgia's rules provide detailed requirements for substantive content of the RFP, including information on all evaluation criteria, transmission impacts, and procurement schedules. Bidders submit offers that include necessary details, such as price terms, technical details of resources relied upon, delivery locations, credit information, and market qualifications. The utilities undertake an evaluation process based on a "total cost impact analysis" as performed in a prior solicitation.

The Georgia Public Service Commission approves the IRP, the final RFP document, and the final resource selection through its "certification of need." After certification, the Commission allows the utility to recover an "additional amount" through rates which is "provided as an incentive for electric utilities to enter into purchase power agreements ... [because] ... if the Companies would only earn on their investments, not on their PPA expenses, they would be more inclined to build than buy."[b]

An Independent Evaluator oversees many phases and components of the procurement process, including review of all participant communications, review of RFP comments and utility responses to such comments, oversight of public web site, and development of an independent evaluation of offers. Additionally the Independent Evaluator provides interim and final reports on the procurement's performance. According to the Independent Evaluator, success in development of model agreements acceptable to all participants, as required by rules, has been "elusive."[c]

[a] Amendments to Georgia Code 515-3-4-.04, Identification of Capacity Resources.
[b] GA PSC Order, 15392-U, December 2002.
[c] Accion Group, Report to the Georgia Public Service Commission on the Georgia Power Company 2009 RFP, p.31.

### 2. Resource Plans and Related Issues Preceding Procurements

For utilities using competitive procurements for incremental resources, the process by which a utility determines what resource(s) to procure through a competitive solicitation often involves and is linked to preparation and regulatory review of a resource plan.

Irrespective of policies with respect to competitive procurements, most utilities with load-serving obligations in states with a traditional industry structure undertake some form of resource planning process. Broadly defined, such a process identifies incremental resource needs using a variety of lenses, including changes in customer requirements, resource adequacy, economics, portfolio mix or diversity, and external considerations (such as environmental policy requirements). In some states, this planning process may require oversight and approval by the state commission in formal integrated resource plan ("IRP") proceedings.[21] By identifying the utility's medium- to long-term resource deficiencies or opportunities, these planning processes are typically the first step in a procurement process in traditionally structured states relying on competitive procurements of incremental resources.

Resource plans have many implications for how resource needs are determined, managed and fulfilled that we do not address in this report. For the purposes of our examination of competitive procurements of incremental supply, we focus on the implications of utility plans for identifying the specific electricity product(s) to be procured from the market. For example, some utility procurements define products very broadly or flexibly, while others define products more narrowly.

More open and flexible procurements, for example, may simply request offers from any resource type/technology delivered to any points within the utility's service territory for a period of some unspecified duration. If a wide variety of types of resources may respond to such requests, the utility will need to compare price and non-price features among offers that may differ along many dimensions.[22] Comparison of such varied offers poses evaluation challenges that inevitably introduce subjectivity into the evaluation process. However, defining products in this way provides the market with the greatest flexibility to propose creative alternatives to meet the utilities' needs most cost-effectively.

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[21] For example, California, Colorado, Georgia, and Oklahoma require integrated resource plans (or similar plans requiring commission approval).

[22] Montana's utility, Northwest Energy issued an open RFP for baseload, dispatchable, shaped and wind resources. The RFP indicated that "The exact quantity and type of resources the Utility procures will substantially depend upon the economic and operational parameters of the bids received and therefore may not match the quantity and type of resources identified as beneficial in the Resource Procurement Plan." Northwest Energy, Request for Proposals, July 2, 2004, prepared by Lands Energy Consulting. Similarly, PacifiCorp's 2009 RFP, which requested 525 MW of supply that could be "prescheduled,", involved solicitation of offers providing for a minimum of 100 MW using any one of eight contractual approaches for terms of 10 to 35 years. PacifiCorp 2009 Request for Proposals, September 2005, Flexible Resource.

Competitive procurements can also define products and potential agreements more narrowly. They might, for example, request specific quantities of renewable power, demand response, or energy efficiency,[23] or request new baseload power plant supply located in or deliverable to a particular zone by a certain start date.[24] Commissions may influence the specificity of these narrower resources procurements through a resource planning process that attempts to identify the type of resources "best" suited to meet the utility's incremental needs. More narrowly defined procurements also eliminate some but not all of the evaluation challenges posed by broader procurements.

Despite the potential benefits of using an IRP process to arrive at a set of narrowly defined resource needs, such a process may result in product specifications based on planning assessments of hypothetical resources rather than on actual prices and resource alternatives offered by the market. For a variety of reasons, important differences may exist between the assumptions used in the planning process and the realities of the markets. Further, utilities may seek to change product definitions (or evaluation criteria) if changes in market conditions make initial resource selections made during planning stages imprudent. Under such circumstances, regulators often must determine whether and, if so, when to review the prudence of the utility's proposed changes. These reviews are likely to be difficult because such amendments may be proposed to avoid investments that are not in consumers' interests or to change opportunistically the terms of the procurement to promote the utility's preferred resources.

In some states, certain types of resources are exempt from commission or legislative requirements that otherwise call for competitive procurements of incremental supply. Exemptions are generally allowed for procurements involving small quantities (e.g., less than 100 megawatts ("MW")) or short durations (e.g., less than one year).[25] These exemptions are provided to avoid imposing excessive administrative burdens on the small, short-term supply purchases that utilities commonly make. While such exemptions provide the utility with needed flexibility to effectively manage a short-term portfolio to maintain resource balances, regulators should also be attentive to situations in which utilities use such exemptions to avoid competitive procurements for longer-term

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[23] In California, the Energy Action Plan creates specific targets for certain preferred resources (including renewable power, demand response, and energy efficiency) to be achieved through separate resource procurements. State of California Energy Commission and Public Utilities Commission, Energy Action Plan II, Implementation Roadmap for Energy Policies, September 21, 2005.

[24] For example, Georgia Power's 2011 RFP requests resources with interconnection to the Northeastern portion of Georgia's grid. Georgia Power, "Overview of the Georgia Power and Savannah Electric 2010 and 2011 RFPs." Southern California Edison's 2005 procurement sought only supply from new generation resources because of the perceived need to encourage new generation to mitigate potential market power and forecasted resource adequacy concerns in that area. Southern California Edison, 2006 Request for Offers, New Gen RFO, Transmittal Letter, V6.0 revised November 30, 2007.

[25] For example, procurements in Utah are required for resource additions greater than 100 MW and for longer than ten years. Energy Resource Procurement Act, 54-17-102. In Oregon, the criteria are 100 MW and five years. Public Utility Commission of Oregon, Order No. 06-446, p. 3.

resources which might produce offers that would otherwise offer favorable terms for customers.

**Box 2**

**Dealing with capital-intensive, new and untested technologies**

Much of the recent experience with utilities' competitive procurements has been limited to solicitation of and/or proposals for procurements of power from natural gas-fired facilities. For a variety of reasons, regulators and utilities may seek to depart from this trend. Recent experiences with using procurements to elicit proposals for baseload resources have varied. Some utilities have sought exemptions from competitive procurements in order to develop coal-fired facilities,[a] while others have asked for proposals (including self-build offers) using coal or nuclear generation technologies.[b]

Development of large, baseload, capital-intensive generation facilities (especially ones using advanced technologies) may raise new types of uncertainties in resource development. First, in some states, development, permitting, and construction risks for coal and nuclear facilities are typically greater than those for natural gas plants. Second, advanced power production technologies face greater technology uncertainty because of their less advanced stage of development. For projects involving advanced technologies (e.g., the next generation nuclear facility, or a large-scale coal facility with carbon capture and sequestration), it may be difficult – either prohibitively expensive or not commercially possible – for suppliers to obtain either equipment manufacturers' performance guarantees or EPC contractors' willingness to take on construction risk.

Capital-intensive advanced technologies pose unique challenges for competitive procurements. Are these risks and technology issues sufficient reason to allow utilities exemptions from competitive procurements? How should these risks, technology issues and need for unique supplier attributes be addressed within eligibility requirements and evaluation procedures? Are there means of effectively quantifying these risks? Are there innovative ways of sharing risks and developing technologies collaboratively that can be developed with potential suppliers, and then built into model contracts that assign an acceptable allocation of risks among suppliers, the utility and, ultimately, electricity customers? These questions are beyond the scope of this review, but are important considerations for policy makers interested in considering the next generation of advanced technologies and how best to use markets as a way to discipline costs associated with them. Further, because the large capital investments necessary for development of these types of resources pose potentially valuable opportunities for utilities to enter new resources into rate base, commissions should be aware that utilities may attempt to shield such projects from competition even in situations where market processes are applicable. Despite these challenges, the potential economic gains from imposing the market discipline of competitive procurements on development of capital-intensive and advanced technologies may be great. In particular, the scope for potential cost savings may be significantly greater than those under procurement of natural gas-fired resources. In light of the expected introduction of greenhouse gas emission controls in the future that will require development of advanced technologies, we encourage regulators and the industry to continue to examine these issues in other forums.

[a] Duke Power, Preliminary Application for Certificate of Public Convenience and Necessity, Cliffside Project, Submitted to the North Carolina Public Utility Commission, May 11, 2005; Public Utilities Commission of Colorado, Order of Settlement, Decision No. C05-0049, December 17, 2004.

[b] PacifiCorp considered benchmark coal resources in its 2009 Request for Proposals for Flexible Resources, and Georgia Power is considering nuclear resources in its 2016 Request for Proposals.

Procurement rules also often allow utilities to petition for exemption from rules requiring a competitive procurement. The reasons for such requests have varied, but have been related to reliability and development risk,[26] or utility financial condition.[27] Some state rules also explicitly allow utilities to petition for "emergency" exemptions if there is insufficient time to implement a full competitive procurement for needed resources.[28] However, some commissions have explicitly cautioned against abuse of such "emergency" self-build proposals, particularly those that arise after a competitive procurement that fails to identify needed resources.[29] For similar reasons, commissions may require that utilities submit a self-build offer to avoid the situation in which the utility rejects all offers in a competitive procurement, and then subsequently submits a self-build proposal to fill resource requirements. When considering such exemptions and requirements as allowed or required under their authorities, commissions must balance potential lost gains from a competitive procurement against the particular factors raised by the utility in its application.

### 3. Procurement Oversight, Stakeholder Participation, and Utility Codes of Conduct

Participation by suppliers, commissions, the public, and independent monitors can be important to ensuring a fair and objective process. Such participation early in the process can also help to avoid (or at least lessen) later regulatory disputes by providing opportunities for differences of opinion, misunderstandings, or information problems to be resolved ahead of the competitive solicitation itself.

#### a. Independent Monitor

Independent monitors have become an important component of procurement oversight in many of the incremental supply procurements, particularly when the procurement includes utility self-build proposals or affiliate bids. State policies, however, differ in their requirements relating to IMs. Apart from the threshold issue of determining

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[26] For example, although North Carolina has no formal requirements for competitive procurements, Duke Energy explicitly requested approval to forgo a competitive procurement given the nature of the proposed resources. Duke Power, Preliminary Application for Certificate of Public Convenience and Necessity, Cliffside Project, Submitted to the North Carolina Public Utility Commission, May 11, 2005.

[27] Public Service of Colorado requested, and was granted, exemption from procurement rules for a 500 MW coal-fired power plant. Among other reasons suggested, Public Service of Colorado argued the need for the project to maintain sufficient equity on financial balance sheet.

[28] For example, Public Utility Commission of Oregon, Order No. 06-446, p. 3. PacifiCorp argued that the purchase of a 500 MW power plant should be exempt from procurement requirements because it is a "time-limited resource opportunity of unique value to customers." See: Clearing Up, "PacifiCorp Signs Stealth Deal to Acquire 500-MW Generator," April 23, 2008; Public Utility Commission of Oregon, Order No. 06-446, August 10, 2006, p. 4. See also Ohio's newly enacted law (127 SB 221) that sets forth the market-condition criteria under which the Commission may not approve the winning bids (and market-based prices) of a competitive procurement process. Sec. 4928.142.(B)(3)

[29] For example, resources may not be selected if they fail to meet a competitive benchmark, such as short-term market purchases. Public Utility Commission of Oregon, Order No. 06-446, p. 5.

whether and when an IM is required to be part of the procurement process, the other key issues include:

- What are the IM's roles and responsibilities (e.g., oversee the utility's actions? Independently evaluate the bids? Select the winning offers?)
- Who selects the IM (e.g., the utility and/or the commission?)
- To whom does the IM report (e.g., the utility and/or the commission?)

Independent monitors are currently required in nearly all states that impose some procurement requirements, although there are exceptions.[30] In some states, IM monitors are required for all procurements;[31] in other states, IMs are required only if utility self-build or affiliate offers are considered.[32]

Using an IM involves many trade-offs in terms of costs and benefits to the process. The potential roles an IM may play (and services it may provide) include:

- Reviewing initial procurement documents (e.g., the RFP, model contracts, credit requirements);
- Overseeing communications with potential bidders, and between utility teams to comply with "codes of conduct";
- Reviewing utility bid evaluation methodologies, and in some cases even carrying out parallel independent bid evaluations;
- Monitoring contract negotiations; and
- Reporting to commission staff and supporting the regulatory review of the entire process and its results.

Appendix A provides a more detailed list of the various activities that IMs often perform.

By playing these roles, an IM may add substantial benefits, particularly in terms of maintaining process fairness and objectivity to mitigate the potential exercise of

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[30] Florida's Rule 25-22.082 does not require that competitive procurements use an independent monitor, although some procurements by Florida utilities may incorporate utility-hired monitors to evaluate certain procurement elements. For example, see Direct Testimony of Alan S. Taylor, In re: Florida Power and Light Company's Petition to Determine Need for West County Energy Center Units 1 and 2 Electrical Power Plant, Docket No. 02162-06.

[31] For example, Oregon (Public Utility Commission of Oregon, Order No. 06-446, p. 6), Louisiana (Louisiana Public Service Commission, General Order, Docket No. R-26172 Sub Docket A).

[32] For example, California requires an IM in all procurements in which the utility or its affiliates has a proposal. California Public Utilities Commission, Decision 04-12-048, Opinion Adopting Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company's Long-Term Procurement Plans, April 1, 2004.

improper self-dealing. However, an IM can also improve the efficiency of the process and the quality of the results. For example, the IM can monitor communications to ensure an appropriate level and substance of communications. The IM can assist in ensuring appropriate resolution of technical challenges that inevitably arise in the course of a complex competitive procurement. Similarly, the IM can monitor and report on the utility's conduct and the procurement's competitiveness as a way to help the commission evaluate whether the results of the procurement should be approved as consistent with just and reasonable rates. In addition to these important oversight roles, an IM may also provide substantive feedback on procurement design and "lessons learned" that can improve effectiveness of future procurements.

Against these benefits of including an IM are the costs to the process – especially the cost of hiring the IM, which can be substantial. However, as many states have determined, the benefits of IMs seem to outweigh these costs in most instances, and are a necessary element of a credible process where the utility itself has a financial stake in the outcome of the competitive procurement itself. In many states, legislation or commission rulings provide specific guidance on these activities, while other states provide no explicit guidance or requirements.[33]

Achievement of these IM benefits requires a degree of separation between independent monitors and the utilities they are overseeing. Thus, decisions about who selects the IM, and to whom the IM reports may affect their independence and their ability to fulfill their duties in effective ways. In some states, IMs are selected by commission staff, potentially with input from various stakeholders, including the utility and potential bidders.[34] In other states, the utility selects the IM, although the commission or its staff usually retains some control over the selection process.[35] In nearly all states, the soliciting utility is responsible for compensating the IM and, in many states, can recover such costs from rate payers (as part of the costs of the procured resources) or through fees imposed on bidders.[36]

[33] For example, Arizona's guidelines provide limited specification of IM duties. Arizona Corporation Commission, Decision No. 70032. In contrast, Utah's rules identify very specific IM roles and responsibilities. Utah Administrative Code, R746-420.

[34] For example, Oregon (Public Utility Commission of Oregon, Order No. 06-446, p. 6), and Utah (Utah Administrative Code, R746-420, Requests for Approval of a Solicitation Process, at R746-420-1).

[35] In Arizona, the Staff endorses a short-list of IMs from which the utility can select. Arizona Corporation Commission, Decision No. 70032, p. 3-4. In Louisiana, the Commission can reject the utility's proposed IM. Louisiana Public Service Commission, General Order, Docket No. R-26172 Sub Docket A.

[36] In Utah, the utility charges "reasonable" bid fees of up to $10,000 per bid to defray IM costs, but can also recover any remaining costs through customer rates. Utah Administrative Code, R746-420, Requests for Approval of a Solicitation Process, at R746-420-5. Georgia also allows the utility to recover IM costs through bid fees up to $10,000 per bid. Georgia Code 515-3-4-.04.

### b. Public (or Stakeholder) Participation

While public participation may occur at any stage of a procurement process, most activity tends to occur in certain discrete periods: (a) during the policy development period when a commission is considering whether to require competitive processes and what structures and rules to require; (b) prior to a particular procurement, when the utility is developing RFP instruments and procedures, defining products and contract terms, and determining information to provide to potential bidders; (c) immediately after the RFP is issued and potential market participants have a chance to gather any additional information they need to respond to the RFP; (d) during a formal process the commission uses to review the results of the procurement; and (e) after the procurement process when the commission is considering what "lessons learned" can lead to process improvements in future procurements.

While public participation during these phases may add time to their completion, such participation may avoid delays later in the process by minimizing incomplete supplier offers and by decreasing the opportunity for misunderstandings or disputes about bid requirements, other RFP terms and conditions, and evaluation procedures. Final RFPs often reflect input from market participants and other interveners obtained through comments on draft RFPs.[37] Workshops provide an opportunity for more informal discussions amongst the procuring utility, regulators, and potential bidders about draft or final RFPs. Such conferences may also provide a means for utilities to clarify particular aspects of RFP terms and conditions.

### c. Utility Codes of Conduct

Because of the inherent and well-recognized potential conflicts of interest that arise in competitive procurement processes where the utility is both a buyer and potential supplier of power, utilities and their affiliates are typically required to act under "codes of conduct" that limit and/or guide certain types of communications and interactions between utility employees. In particular, these codes of conduct limit and guide communications between the utility's personnel with different functions: the team of individuals developing utility self-build proposals, the team evaluating competitive offers, the team providing estimates of transmission impacts, and the team administering the utility's transmission functions.[38] By operating pursuant to these conduct codes and

[37] For example, comments to draft RFPs have be requested by utilities in various states, including Georgia, Louisiana, Oregon, and Utah. For example, see, the Georgia PSC maintains a web site providing access to draft RFPs and comments from all interveners. <https://www.gpscie.com/_gpscie/home.asp >. See also, Entergy Services Inc., 2006 Request for Proposals for Long-term Resources, April 17, 2006.

[38] For example, see, Georgia Public Utilities Commission Rules, 515-3-4-.04; Utah administrative Code R746-420, Requests for Approval of a Solicitation Process. We also note that FERC's Standards of Conduct govern interactions between utility personnel involved in certain transmission functions and other personnel. See, Standards of Conduct for Transmission Providers (see, e.g., 122 FERC ¶ 61,263, Standards of Conduct for Transmission Providers Docket No. RM07-1-000, Notice of Proposed Rulemaking, March 21, 2008)

standards, the utility's bid evaluation team is less likely to bias decisions in favor of the utility's or its affiliate's proposals, and the utility's teams developing self-build or affiliate offers are less likely to have advantageous access to confidential information not available to all bidders. IMs often oversee such interactions to ensure that utilities are not in violation of these prohibitions and requirements.

Procurement processes vary in the means by which any offers from an affiliate and self-build proposals are introduced into the solicitation process. In some cases, such offers must be submitted under seal ahead of those of other bidders to provide assurance that these offers have not been shaped with knowledge of information from other proposals.[39] In other cases, utilities compare supplier offers against utility or market benchmarks whose content may or may not be known to suppliers prior the submission of their offers. The utility may choose to reject all offers that fail to beat either type of benchmark. In all of these cases, there need to be safeguards so that market participants know in advance the rules for how affiliate proposals and self-build offers will be treated.

## 4. Design/Structure of the Evaluation Process

### a. Evaluation Timing

The process of evaluating and selecting offers in incremental supply procurements takes at least many months. During this time period, bidders are typically required to honor the terms of their initial offers, which can create financial risk for suppliers due to fluctuations in the cost of construction materials, fuel prices and other cost factors. Because suppliers are likely to add risk premiums to their offers to capture such risks, procurements that minimize the time between submission of offers and awarding of contracts are likely to encourage offers with lower prices, all else equal. By reducing these supplier risks, keeping the evaluation period as short as possible helps to reduce such risks and costs. However, it is difficult to eliminate such costs altogether. The evaluation of incremental resource offers is, by its nature, highly complex and time consuming due to the need for multiple stages of analysis, development of supplemental data, complex production simulation modeling, and multi-attribute comparisons of offers. Thus, an evaluation that is hurried may result in poor resource choices.

While some procurements result in the selection of bidders within three to four months,[40] it is not unusual for procurements to take significantly longer. In practice,

[39] An IM can manage the receipt of supplier bids and dissemination of certain parts of the bids to the evaluation team during different stages of the process as ways to prevent any (intentional or unintentional) preferential treatment.

[40] For example, in Montana, Northwest Energy's 2004 all-source procurement scheduled roughly four months between bid submission and contract signing. Northwest Energy, Request for Proposals, Issued July 2, 2004. Similarly, PacifiCorp's 2009 RFP was scheduled to achieve a selected offer for more detailed

evaluation periods will reflect many factors such as the number of offers anticipated, the complexity of the required quantitative evaluations given system conditions, the number and complexity of evaluation criteria, and the diversity of supply offers in terms of contractual forms, resource types, and other factors that complicate offer evaluation. Given such differences, utilities should tailor procurement schedules to the types of resources that are being procured.[41]

Given the costs of delays in competitive procurements, procurement design should consider taking steps to shorten evaluation periods and taking steps to mitigate against unanticipated events that may create delays. For example, public participation prior to issuance of the RFP may reduce delays by increasing the likelihood that suppliers conform with bid requirements. Similarly, IMs may have to help mediate unanticipated events that lead to disputes or require arbitration of appropriate procedures.

### b. Contract Negotiation, Including Model Agreements and Bid Refreshing

Just as with the process to purchase a house, the multi-faceted nature of incremental resource procurements suggests that some degree of negotiation after initial bids are received is inevitable. The extent of such negotiations can vary from relatively minor adjustments in the RFP's model contract terms, to negotiations over payment terms and more substantive elements on contract terms. Allowing broad negotiations after offer selection creates incentives for suppliers to understate initial offers and then attempt to recapture value during contract negotiations. Such broad negotiations may also reduce the transparency of the procurement process. However, some scope for negotiation in the terms of incremental resource agreements is important to ensure that potential modifications that expand the scope of benefits to suppliers and utilities can be considered.

Competitive procurements often make their policies regarding negotiation of contract terms explicit to ensure that both the utility and the supplier have common expectations about the likelihood of such negotiations when initial offers are being reviewed. In particular, utilities have explicitly allowed an opportunity for suppliers to "refresh" offers (usually only downwards) at a pre-determined point in the evaluation process, often after a short-list of offers has been identified.[42] Allowing suppliers to "refresh" offers

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negotiations within three months. PacifiCorp 2009 Request for Proposals, September 2005, Flexible Resource, December 1, 2005.

[41] For example, Southern California Edison's 2006 procurement for new generation includes both a Fast Track (five months) for projects that are well into or have completed development phases and are ready to move to construction phases and a Standard Track (14 months) for projects that are earlier in the development process. Southern California Edison, 2006 Request for Offers, New Gen RFO, Transmittal Letter, August 14, 2006.

[42] For example, see Benson, Elizabeth, "Report of Elizabeth Benson, Process Independent Monitor of the Entergy Services Inc. 2006 Request for Proposals for Long-term Supply-side Resources," Docket No. U-30192. September 14, 2007.

may reduce their financial risks given the potentially long delays between bid submission and the awarding of contracts. Of course, such an opportunity also invites suppliers to understate their initial offers. Also, to the extent that there are opportunities for the utility to refresh the cost terms of its self-build proposals, other competitive suppliers should also be given similar opportunities. In some cases, indicative offers are used as a means to move offers into a final stage at which the suppliers sharpen their pencils and refresh their bids.[43]

Most RFPs include model contracts, which provide bidders with guidance about the utility's preferred terms and conditions and about expected allocations of risk among the buyer and seller which would affect the price terms offered by the bidder. The value of such model contracts is that they provide suppliers with a common set of assumptions about the overall shape of an ultimate transaction. The more these terms parallel those which the utility itself will face if it proposes a self-build offer, the fairer will be the competition between proposals from third parties and the utility and the less likely there will be proposal differences that lead to improper self-dealing.

However, model contracts accompanied by tight limitations on contract negotiations may unnecessarily constrain the range of mutually beneficial agreements between suppliers and utilities. Many utilities recognize the potential cost of such constraints and allow suppliers to propose alternative contractual arrangements as part of their initial offer. In contrast, amendments to model contracts may penalize the supplier's offer, since the bidder is typically prohibited from raising a final offer price relative to the indicative offer. In either case, procurements should clearly state the conditions related to amendments to model contracts to avoid a situation in which some suppliers design their offers around model agreements to avoid penalties, while other suppliers offer amendments to model agreements under the belief they will be able to negotiate a more favorable allocation of risk without being penalized in their price terms.

### 5. Commission Reviews of Procurement Process and Results

State commissions have many opportunities to review and approve particular aspects of the procurement process. Regulators often do so – formally or informally – during certain periods: (1) an IRP process when the utility may be identifying the type and amount of incremental resources it plans to procure and/or build; (2) RFP design, which may occur if the utility proposes a design in advance of implementing the RFP; (3) offer evaluation and selection; or (4) the approval of agreements (or proposed self-build investments) and cost-recovery related to them.

When making such choices, commissions face not unfamiliar problems of balancing their role of providing prescriptive policy guidance and holding the utility management

[43] Where this occurs, it is one more instance in which the utility's team responsible for refreshing its self-build offer should not have access to commercially sensitive information from other potential suppliers' bids.

responsible and accountable for its own decisions. While commissions in some states actively participate in overseeing different stages of procurements, other commissions take a relatively light-handed role in intervening in utility management analysis and decision-making until utility proposals are formally submitted for approval.[44]

A critical issue affecting those states that have chosen to use a competitive procurement process for incremental resources, of course, is the signals sent by regulatory reviews and decisions with regard to the regulators' actual commitment to the competitive process and the assurances regulators will provide with regard to recovery of the costs of transactions emanating from the competitive process. Regulators thus end up balancing competing objectives. On the one hand, they must consider the need to provide assurance to the market about cost-recovery. On the other hand, they need to maintain their ability to act on consumers' behalf to deter imprudent utility actions and maintain "fair and just" energy prices.

Commission rulings that allow the market (and investors) to infer relatively greater commitment to the outcomes of a competitive procurement process may reduce uncertainty about the utility's ability to recover the costs of PPA(s) that result from a procurement. This in turn can reduce the associated regulatory and financial risks, and any cost premiums associated with them.[45] For complex competitive procurements for incremental supplies, it may be difficult (if not impossible) for regulators to provide utilities with a before-the-fact, iron-clad commitment to allow cost recovery for any transactions that result from a competitive procurement found to have been fully competitive (unless such regulatory authority were sanctioned in a state's legislation). That said, once regulators (or their legislators) have called for reliance on competitive procurements, the actions of regulators to show their willingness to allow cost-recovery of transactions resulting from solicitations found to be competitive will help to buttress a favorable investment climate in the state. Commission approvals may also provide other market participants with greater confidence that the commission supports the outcome of the procurement process. Thus, for example, approval of the utility's proposed RFP process may provide the market with greater confidence that the commission supports the procurement process and that the procurement will eventually result in signed agreements with suppliers.

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[44] Members of the North Carolina PUC have referred to their role as a quasi-judicial entity, which responds to utility/regulatory issues and controversies brought to the commission to resolve. At the other end of the spectrum on procurement issues is the Maine PUC, which is the entity that actually decides what resource(s) to select in the context of procurements and then assigns such resources and related costs to regulated utilities in the state. (Ohio's new law gives the PUC authority to select winning offers of competitive procurements under some circumstances.) In the middle are a large number of states with traditional or hybrid electric industry structures (e.g., Arizona, California, Georgia, Louisiana, Oklahoma) with an array of utility practices, in which the state gives more or less guidance over preferred procurement approaches, and different levels of supervision and decision-making about utility actions in different phases of the RFP process.

[45] All else equal, the longer that a bidder has to keep its resource out of the market while its bid is being considered by a utility in the course of a procurement, the higher the opportunity costs and other risk premium will be built into the offer price.

## D. IMPLEMENTING THE PROCUREMENT: THE UTILITY'S EVALUATION OF OFFERS

### 1. Overview

As described earlier, offers to provide incremental resources typically vary along multiple dimensions related to the type and character of resources offered, and the structure of the proposed contractual arrangements. Because incremental supply offers may differ along many of these dimensions, utility evaluations must consider trade-offs across various criteria related to economic, reliability and other considerations. Key criteria for evaluation of offers include:

- Price, on a dollar per kilowatt and a dollar per megawatt-hour basis, reflecting anticipated fixed and variable payments given likely dispatch as part of the utility's system;
- System benefits (related to congestion relief or transmission losses) or costs (in terms of transmission upgrades necessary to enable a resource to power in accordance with the proposed agreement);
- Shifts in risks among the utility, the seller and retail customers associated with various provisions in the contract, such as fuel price indices, availability penalties, collateral requirements of the utility and supplier; and
- Other non-price policy factors and considerations (e.g., environmental impacts, development risk for a new project, the utility's fuel or portfolio diversity, etc.).

A successful evaluation should attempt to account for these costs and risks, assign weights that appropriately reflect the value proposition (and risks) to customers, make comparable evaluations across all offers (including self-build and affiliate offers), and complete evaluations in a timely and efficient fashion to provide proper incentives for bidders.

To reduce evaluation costs and the time between offer submission and selection, evaluations typically proceed in three stages, including: (i) identification of bidders and/or offers meeting basic eligibility requirements; (ii) a preliminary evaluation to identify a "short list" composed of the "best" offers; and (iii) a full evaluation of "short-list" offers to identify a final selection. While most incremental resource procurements follow such a three-step process, there is little uniformity in how (and whether) particular evaluation criteria are considered in each of these stages. However, in general, initial eligibility criteria are utilized primarily to ensure that offers meet financial and electricity market participation criteria necessary to deliver power reliably.

### 2. Economic Modeling of the Benefits and Costs of the Offer as Part of the Utility's System

Evaluation of offers – at least the set of short-listed offers – typically involves an analysis of how an offer and/or groups of offers, interacts with the utility's system. This typically involves a series of simulations of the system with different base-case conditions and with different offers or groups of offers, along with sensitivity analysis exploring the robustness of outcomes under different fuel prices conditions.

Final evaluation of the costs of proposed power supplies, including associated transmission-related impacts,[46] typically relies on the use of highly detailed production cost models among other things. These models have a long history of use within the context of utility planning and regulatory proceedings. As such, we do not revisit the many issues arising in the proper valuation of the costs of alternative electricity supply resources. Several issues regarding the use of these models within the competitive procurement context are, however, worth noting.

Due to their complexity, production cost models (and their data inputs and assumptions) used to evaluate and compare the economic costs of various offers may have limited transparency to market participants. While frustrating to market participants concerned about whether their proposals have been treated fairly and objectively, there are inherent challenges in opening these processes up for public scrutiny. Competitive procurements may take several approaches to ensuring that modeling is performed in ways that support fair and objective evaluations. First, utilities might rely on the same production cost models used in other regulatory proceedings. Past experience with such models may reduce the cost of oversight of the evaluation process. Second, regulators or independent monitors may review portions of the utility's evaluation studies, perform completely independent evaluations of all offers, or perform evaluations using the same models as the utility's evaluation team. In particular, review of modeling assumptions and data prior to the submission of bids may allow any controversial issues to be identified and resolved prior to the evaluation stage.[47]

To the extent possible, utilities should aim to provide bidders with information about input assumptions used in these models, such as demand forecasts and key parameters of other system resources. This will allow suppliers to shape their competitive offers to be more attractive than other offers. However, utilities may find it prudent under some circumstances to revise these assumptions during the course of the evaluation process, so that evaluations reflect up-to-date market conditions. Procedures for updating data

[46] In Section VI.D.7, "Transmission", we discuss these types of costs, including congestion impacts, losses, and any transmission-system upgrades that may be needed to integrate a new resource into the utility's transmission system.

[47] As these evaluations frequently rely on assumptions and models developed as a part of the utility's IRP process, the evaluation structure has already undergone some degree of review. For an example of an independent model evaluation, see, Potomac Economics, Independent Monitoring of the Evaluation of Proposals for Entergy Long-Term Supply-Side Resources, Solid-Fuel Final Report, September 2007.

should be specified prior to evaluation and be sensitive to concerns about the transparency of evaluation procedures or improper self-dealing.[48] Certain design procedures might mitigate these tensions, such as indexing key assumptions to publicly available metrics. The involvement of IMs may mitigate such concerns through review of modeling assumptions or implementation of parallel, independent evaluations.

In some procurements, offers are compared to "benchmarks" that reflect estimates (but not actual offers) for a utility self-build facility or purchase of power on short-term wholesale markets. The potential use of such benchmarks may present a dilemma for regulators, however, if they are faced with having to decide what to do in the event that no offers beat the assumed benchmarks, that the benchmarks do not reflect the actual products being procured in the RFP, or that cost-recovery policies for utility self-build proposals do not bind the utility to these benchmarks.

Finally, choice of evaluation methodology may have implications for comparing offers that differ along certain dimensions. For example, comparison of offers of different duration (e.g., comparing a 15-year contract offer to a "life-of-unit" self-build proposal) is sensitive to methodology choice, since these methodologies implicitly make different assumptions about the prices that prevail for periods when offers of different duration do not overlap.[49] End-effects associated with offers of different duration can have a large impact on overall system benefits and costs, and therefore must be treated with care when evaluating proposals with significantly different terms. Commission guidance on these and similar technical issues prior to issuing an RFP may contribute to more efficient processes in the end.

### 3. Economic and Financial Risks

Competitive procurement of incremental resources involves important questions associated with who bears the burden of the financial and economic risks in power supply arrangements, as between:

- the power supplier (as seller) and the utility (as buyer) in a PPA;
- the utility and its customers in a PPA; or
- the utility and its customers in a self-build proposal in which commissions will eventually determine cost-recovery on the investment.

[48] For example, see, Staff of the Public Utilities Commission of the State of Colorado, Report on Public Service Company of Colorado's 2003 Least-Cost Resource Plan, Volume 1: Commission Rules and Practices, Docket No. 07M-147E, June 14, 2007.

[49] Boston Pacific Company. "Bid Evaluation Methods in Competitive Solicitations: A White Paper on Techniques Used to Evaluate Power Supply Proposals with Unequal Lives," prepared for Calpine Corporation.

In fact, because of their ability to influence the allocation of certain risks, competitive procurements have begun to be used in utility settings as a means to address core issues associated with such risks.

The cost of arranging for and obtaining generation services on behalf of retail customers depends on many uncertainties. Regulators are quite familiar with many of these risks: the risk of fuel price increases; the risk that it will cost more to construct a plant than originally expected; the risk that new laws will be enacted that change the future investment requirements and operating costs at a power plant; the risk that a plant will not perform as expected over time; and so forth. Regulators understand these and other categories of risk and have addressed them in a variety of ways over time.

The magnitude of such risks depends on many factors. In particular, three risk factors are important to competitive procurement of incremental supply: (i) the assignment of obligations and responsibilities between the buyer and the seller, as set forth in agreements; (ii) the character of inherent risks associated with the type of resource involved in offers; and (iii) the risks associated with the development status of power plant projects underlying different supply offers.

**Table 7:**
**Illustrative Shifts in Financial Risks for Alternative Supplier Agreement Structures**
**∗ = Risk shifted to supplier relative to a self-build with no comparable agreements in place (illustrative)**

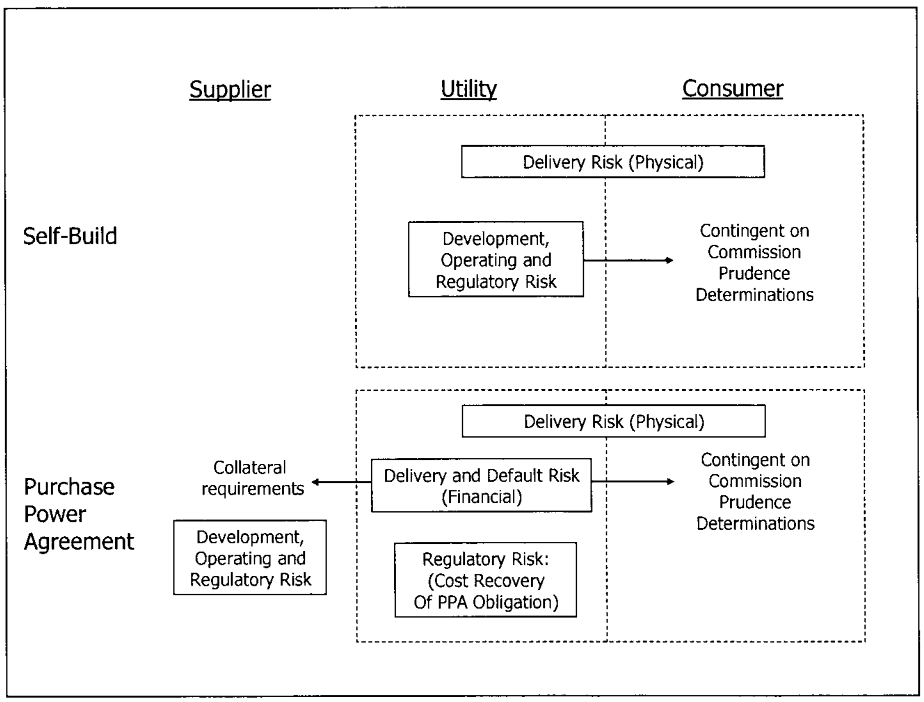
| Types of Risks (examples): | Engineering, Procurement, Construction Agreement | Asset Purchase and Sale Agreement | Tolling Agreement | Purchase Power Agreement |
|---|---|---|---|---|
| Development Risks: | | | | |
| Construction Risk (timing, cost) | ∗ | ∗ | ∗ | ∗ |
| Operating Performance and Cost Risk | | | | |
| Fuel Price | | | | ∗ |
| Heat Rate Performance<br>O & M Costs Specific to a Plant<br>Power Plant Availability | | | ∗ | ∗ |
| Regulatory Risk | | | | |
| Cost-recovery Risk | | | ∗ | ∗ |
| Environmental Policy Risk | | | ∗ | ∗ |

Note: Some risks can be shared between suppliers and the utility (and its customers) through various means, such as indexing measures relying on fuel price or construction cost indexes. Indexing can control for market risks, but not idiosyncratic risks associated with supplier performance.

How these risks are allocated between third-party suppliers, the utility (as buyer in a PPA or as a power plant owner) and retail customers is a fundamental issue for utilities and regulators relying upon competitive procurements. Table 7 shows how the terms of PPAs can shift various project risks away from the utility (and its retail customers) to suppliers, as compared to utility self-build. With a self-build, these risks are distributed between utilities and customers depending on commission rulings.[50] By contrast, at the other end of the spectrum are PPAs. These agreements shift many of these risks to suppliers, by requiring, for example, that they deliver replacement power at a certain price even if fuel prices increase or pay other penalties if the plant performs poorly. Other types of agreements, such as those presented in Table 7, shift certain pieces of these financial risks.

The development, operating and regulatory risks identified in Table 7 reflect only a portion of the entire risk story. Figure 1 provides a stylized illustration of the distribution of risks under a PPA, on the one hand, and a self-build approach, on the other. There are various ways to assign responsibility for certain risks identified in Figure 1. For example, default and delivery risks from PPAs can be mitigated through supplier collateral requirements and/or other performance penalties. Also, utility risks from uncertainty over recovery of the costs of contractual agreements made with suppliers (so-called "debt equivalency") can be mitigated through certain measures. The sections that follow provide further discussion of each of these risks.

**Figure 1**
**Illustrative Distribution of Financial Risks of**
**Self-Build and Purchase Power Agreement Offers for Retail Supply**




[50] Such regulatory decisions include, for example, determinations as to the prudence of utility actions when the it proposes to add investment to rate base (whether at the point when the project becomes used and useful, or over time as new capital investments are required at the facility). Other cost recovery decisions are made over the life of the plant (e.g., utility fuel purchases of fuel and plant operating performance.)

Other aspects of agreement structure can also impact the distribution of financial risks. For example, financial risks to suppliers can be shifted back to the utility (and its customers) by making energy-related payment terms dependent on market prices as reflected in publicly available price indices, or by making capacity-related payment terms tied to changes in construction cost indices during the construction period. By using these and other mechanisms, utilities and commissions can design procurements to achieve a desired distribution of these risks and – to some degree – avoid the challenges of reliably assessing the economic cost imposed by these risks.

In principle, evaluations should aim to account for the allocation of various risks when comparing alternative supply offers. Figure 1 illustrates how the distribution of these financial risks can vary dramatically between a PPA and a utility self-build project. While PPAs shift much of the development and operational risks traditionally associated with a cost-of-service regulatory model to third-party suppliers, they leave utilities with the risk that regulators may decide not to approve cost recovery for contracted power. Because of this risk, many utilities condition any contracts they sign with bidders (as a result of a procurement) upon regulatory approvals of cost-recovery of contract payments.

Measuring the implications of alternative contractual forms for the transfer of risk is complicated by many factors. First, many of the uncertainties are difficult to quantity given limited information and limited experience with the relevant risk. The shifting of risk is never as tidy as suggested in Figure 1 despite contractual provisions.[51]

Second, the relevant financial risks vary not only with contractual form but also with other attributes of suppliers' offers, such as the type of proposed technology. Some technologies (e.g., gas-fired combustion turbines) rely on equipment for which there is significant construction and operating experience; this creates relatively low financial risk. By contrast, other technologies require plant construction tailored to particular site conditions (e.g., large baseload facilities) or have relatively little operating experience (e.g., coal-fired integrated gasification combined cycle facilities). Further, uncertainty in future fuel prices, future environmental policy (particularly with regard to greenhouse gas emissions), and transmission infrastructure availability (e.g., for remote wind power) may create differences in financial risks of competing offers that are difficult to compare.

Finally, a contract framework may not fully capture certain development risks faced by the utility due to its obligation to maintain the reliability of the electric system. Thus, while some contractual provisions, such as collateral requirements, may mitigate certain financial aspects of development and delivery risks, they may not mitigate the physical risk that suppliers fail to develop generation resources needed to maintain system adequacy requirements.

[51] For example, EPC agreements may not fully shift development risks given contractual clauses that provide contractors with opportunities to plea for changes in original agreement terms, including change orders that inevitably occur given the difficulty of fully specifying the facility prior to construction.

### 4. Credit

Utilities that enter into PPAs face the risk that suppliers will be unable or unwilling to deliver in accordance with the agreement's terms. In parallel, suppliers face the risk that the utility will be unable to pay for contracted-for supplies. These uncertainties create financial risks because utilities may incur higher costs to replace supplies that are not delivered, or because the seller may lose revenues if a utility bankruptcy or regulatory action undermines the utility's ability to pay what is owed to the seller. To mitigate these and other financial risks, utility procurement processes introduce various means to evaluate the credit of sellers and to identify suppliers less likely to impose such risks. In addition, the PPAs can create incentives for suppliers and utilities to fulfill agreements as specified, and can minimize either party's financial losses in the event the other fails to perform.

One typical requirement in competitive procurements is a minimum credit rating that all bidders are required to meet. When used, such criteria should be transparent to suppliers so they have sufficient opportunity to address any credit deficiencies and to avoid such standards from inadvertently excluding suppliers from participating in the procurement.

Potentially more important than these credit standards are the financial guarantees or collateral requirements imposed on suppliers (and in some cases, of the utility as the buyer). These guarantees ensure that the counterparties to the PPA have access to sufficient funds to recover contractual penalties or remedies in the event that either the supplier or the utility cannot fulfill its obligations under the agreement. By ensuring the availability of these funds, the incentive to renege on the agreement's terms is reduced, and funds are available to compensate for the corresponding financial losses, such as utility losses arising from the need to replace power the supplier has failed to deliver.

The following list identifies key issues related to the design of supplier collateral requirements and are discussed in further detail in Appendix B (along with a summary of collateral requirements in selective procurements):

- The level of financial guarantees. The level of credit required should reflect a balance between (a) the benefits of insuring against financial losses and creating proper supplier incentives, and (b) the costs of imposing additional financial requirements on suppliers that are likely to increase the price of their offers (or the depth of offers submitted into the procurement). Some methodologies, such as those reflecting mark-to-market accounting, adjust the required level of financial guarantees to market conditions over time.[52] Utilities that make explicit the assumptions and methodology used in setting required levels of credit

[52] KEMA, "The Cost of Credit: A Review of Credit Requirements in Western Energy Procurement," prepared for the California Energy Commission, CEC-300-2006-014, 2006, p. 6.

provide regulators and stakeholders with greater opportunity to assure the reasonableness of these requirements.[53]

- Collateral requirements during procurement. To ensure that suppliers' offers are sufficiently developed and financially credible, some utilities require bid deposits when offers are initially submitted, and/or require financial guarantees of the offers chosen for the "short-list" of considered offers. However, such requirements may act as a barrier to entry for smaller and less-well-financed suppliers, which may be a particular constraint in some procurements, such as those for renewable resources.[54] As a result of this trade-off, regulators and utilities should carefully consider the likelihood that non-bona-fide offers will be a problem, as regulators/utilities determine whether and what kind of bid deposits and other financial guarantees to require in the initial stages of offer submission and review.

- Collateral requirements over the contract life-cycle. The level of financial guarantee necessary to address delivery risk varies over the project's life-cycle, with different risks associated with bid selection, development and operation stages. PPAs should appropriately address these changing realities over the course of the supply agreement.

- Flexibility in the means of fulfilling collateral requirements. To minimize the cost to suppliers of providing collateral, utilities can provide suppliers with alternative means of fulfilling these requirements. In addition to letters of credit, financial guaranties from credit-worthy entities, and cash, the utility may consider other forms of guarantee, including second liens, claims to plant warranties or insurance policies, or step-in rights, in which the utility can take-over project development in the event of developer default.[55]

### 5. Debt Equivalency [56]

Over the years, utility obligations made under PPAs with third party suppliers have given rise to concerns about the best way to assess the implications of such financial risks on

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[53] For example, in PacifiCorp's 2012 RFP process, delays in producing details regarding credit requirements and a justification for the credit approach eventually proposed raised concerns for the Independent Evaluator and various stakeholders. Merrimack Energy Group, Inc., "Report of the Independent Evaluator Regarding PacifiCorp's 2012 Request for Proposals for Base Load Resources" August 30, 2006.

[54] KEMA reports that short-list deposits for proxy projects in California Renewables RFPs were $300,000 in three of three of ten RFPs reviewed and over $1.5 million in another. KEMA, 2006, p.4 and 11-11.

[55] Aspen Environmental Group and Sentech, "Lowering the Effective Cost of Capital for Generation Projects, California Credit Policies Report, Summary of June 27, 2006 Workshop," prepared for the California Energy Commission, CEC-100-2007-001, 2007.

[56] Several references provide a broad overview of debt equivalency issues, including: Brattle Group, "Understanding Debt Imputation Issues," prepared for the Edison Electric Institute, 2008; GF Energy LLC, 2005.

utilities and their investors. In general, there are two issues associated with financial and ratemaking treatment of PPAs that are relevant in the context of competitive procurements.

First, under a PPA, the utility's contractual obligations to the supplier may create a financial risk if this obligation is not matched with a correspondingly firm expectation about the utility's ability to recover such costs from consumers in rates. This financial risk may arise because PPAs set up binding commitments that must be paid under the contract, such as certain fixed payments for available capacity or take-or-pay energy payments. The lack of a corresponding regulatory promise of cost recovery would thus create a potential financial risk for the utility. Second, despite these potential risks, commissions have traditionally treated utilitys' obligations to pay suppliers under PPAs as expenses for ratemaking purposes, thus allowing the utility no opportunity to earn a financial return; by contrast, when utilities pursue capital investments (such as self-build power plant proposals), the utility has the opportunity to earn a return of and on its investment. This can affect not only value of the utility's investment opportunities, but also its capital structure, in some circumstances. While not generally recognized as such by commissions, the utility's commitments under PPAs are generally recognized by credit-rating agencies as debt-like obligations on utility balance sheets. Because these credit ratings affect utilities' overall cost of borrowing on debt markets, a PPA might affect a utility's cost of capital irrespective of commission treatment of PPAs. As a result of these issues, utilities are concerned with commission treatment of a number of related issues, including commitment to PPA cost recovery, access to adequate investment opportunities, and the impact of PPA's on utility capital structure. As a result, so-called "debt equivalency" issues have become an area of tension as commissions expect regulated utilities to undertake procurement processes that may lead to PPAs.

Over time, two basic approaches to addressing debt equivalency issues have evolved. In one, these issues are addressed as part of the overall utility ratemaking process. In a utility's rate case during which its capital structure and cost of capital are determined, regulators consider what adjustments (if any) to a utility's allowed returns (e.g., cost of equity, capital structure) are appropriate in order to acknowledge impacts on the utility when it enters into PPAs with debt-like obligations. In the other approach, these issues are addressed during the evaluation of PPAs when the utility compares offers from third parties to those of a utility self-build proposal. In this approach, the utility makes adjustments to the economic cost of PPA offers to reflect the inferred value of the PPAs' impact on the utility's debt costs. (Appendix C provides further details on construction of such adders.)

In general, regulatory decisions about how best to adjust any inferred debt are complicated by the less-than-complete empirical evidence available on the financial risks associated with PPAs versus other means of supply. To date, there is relatively little research that has assessed how alternative means of fulfilling resource needs impact a utility's overall cost of debt or return on equity.[57] In fact, there is even uncertainty regarding how PPAs impact the credit ratings developed by credit-rating agencies. While certain credit agencies have clearly described certain quantitative balance sheet adjustments made for PPAs, they also note that these are only one among many possible adjustments that may affect a utility's credit rating.[58] However, because many of these other considerations are less clearly described and are more qualitative in nature, determining a PPA's net impact on utility credit ratings is difficult. These considerations again caution against assessment of debt equivalency, or any risk factor, outside of a comprehensive evaluation that accounts for all of the various risks posed by alternative utility obligations and commitments from the standpoint of consumers, while leaving the utility fairly compensated for its financial risks. These issues are normally addressed by commissions in general rate cases in which regulators examine the capital structure and cost of capital of the utilities they regulate.

State policies regarding debt equivalency vary substantially and continue to evolve. A few states have allowed adjustments for inferred debt associated with PPAs in rate proceedings.[59] For example, in Colorado, Public Service Company of Colorado's equity ratio was increased to account for the debt equivalent value of PPAs on the company's balance sheet.[60] More common is the use of debt equivalency "adders,"[61] although many commissions have disallowed the use of adders proposed by procuring utilities.[62] In states that allow the use of debt equivalency adders, the quantitative measure of financial risk used in these adders has varied significantly.[63]

[57] One study suggests that PPAs have little effect on a utility's cost of capital, while utility self-builds actually raise the utility's cost of capital. While various limitations to this study caution against reaching any broad conclusions from its results, the results do suggest that it is important to understand the risk tradeoffs posed by alternative agreement forms when assessing the risk posed by any individual agreement. Kahn, Edward et al., "Impact of power purchased from non-utilities on the utility cost of capital," Utilities Policy 5(1): 3-11, 1995.

[58] For example, Standard & Poors notes: "That said, PPAs also benefit utilities that enter into contracts with supplier because PPAs will typically shift various risks to the suppliers, such as construction risk and most of the operating risk." Standard & Poor's. "Standard & Poor's Methodology For Imputing Debt for U.S. Utilities' Power Purchase Agreements," Ratings Direct, May 7, 2007.

[59] For example, Colorado, Florida, and Wisconsin.

[60] See Colorado Public Utilities Commission, Final Decision, C05-0049, ¶95, December 17, 2004.

[61] For example, procurements in Florida, Louisiana, and Washington allow debt equivalency adjustments.

[62] For example, procurements in California, Colorado, Connecticut, and Georgia do not use debt equivalency adjustments. In some cases, this decision was reached as a result of settlement, rather than commission policy. For example, see Public Utilities Commission of Colorado, Order of Settlement, Decision No. C05-0049.

[63] "Risk factors," which are commonly used to measure the level of regulatory risk when calculating debt equivalency adders, range from 15% to 50% among procurements we are aware of. Washington allows a risk factor of 40% for take-or-pay contracts, and 15% for other PPAs. Puget Sound Energy, All-Source RFP Pre-Proposal Conference, February 11, 2004, Meeting Notes, as referenced in: GF Energy, 2005. In Louisiana, Entergy's use of a 50% risk factor was approved by the Commission. Potomac Economics. "Independent Monitoring of the Evaluation of Proposals for Entergy Long-term Supply-side Resources, Solid-Fuel Final Report," Exhibit DBP-2. Docket No. U-30192, 2007.

However, state policies continue to evolve both in terms of how to account for potential inferred financial impacts and the quantitative measure of such impacts. For example, after initially allowing use of inferred debt adders, California has recently precluded utilities from using such adders in its procurements, while recognizing the potential for recovery of potential inferred debt impacts in later rate hearings.[64] Commissions can also mitigate such risks by increasing assurances about PPA cost recovery, which will likely affect how rating agencies take PPAs into account in their evaluations.

### 6. Economic Risk Mitigation Aspects of PPAs

Under self-build proposals, regulators typically must make decisions about which of the utility's actual investment and operating costs are prudent, used and useful, and therefore recoverable from ratepayers. However, the timing of these decisions is sometimes out of synch with competitive procurement cycles. Therefore, there is a special challenge for procurement processes to deal with the potential situation in which the utility determines that its self-build proposal is more attractive for customers than any of the offers from the market, rejects offers from the market, and then proceeds in pursuit of its own plant.

Under a self-build proposal, it is not until much later on – after actual construction of the facility and in light of the actual costs incurred in doing so – that the utility takes its investment in plant to regulators to determine cost-recovery for the plant. By that time, the original offers from the market may be quite stale and may not reflect what was reasonably known at the time the decision was made to proceed with self-build proposal. The regulator will have to address what market or other information to use in considering the cost-effectiveness of the actual plant as built by the utility and whether the utility's actual costs were prudently incurred. In the end, the utility's self-build costs may turn out to be much higher than anticipated at the time the alternative offers from third parties were rejected.[65,66] (Similarly, performance of a self-build plant may end up

[64] California Public Utility Commission, Opinion Adopting Pacific Gas and Electric Company's, Southern California Edison's, and San Diego Gas & Electric's Long-Term Procurement Plans, Decision 07-12-052, December 20, 2007.

[65] Not only in the past, but also in more recent instances, actual cost overruns for utility self-build facilities illustrate that these risks are real. The history of past nuclear plant cost overruns is well known in the electric industry. See, for example, Bonbright, James C. et al., Principles of Public Utility Rates, Public Utilities Reports Inc.: Arlington, VA, 1988, p. 257-8. More recently, self-build projects developed by Entergy in Louisiana and Duke in North Carolina have experienced similar cost increases. See National Economic Research Associates. "Competitive Electricity Markets: The Benefits for Customers and the Environment," prepared for the COMPETE Coalition, 2008, p. 14.

[66] It is also possible for self-build plants to end up costing the same or less than originally anticipated. A recent example of a utility self-build project which ended up with a lower cost (on a dollar-per-kilowatt basis) than originally expected is Sierra Pacific Power Company's new Tracy Combined Cycle Unit in Nevada. It was originally approved by regulators at a budget of $421 million for a 514-MW unit, and ended up costing that amount for a unit with a 541-MW unit; in effect, the cost went from $819/KW to $778/KW. Sierra Pacific Power Company, Application to Increase Annual Revenue Requirements, Before the Public Utility Commission of Nevada, Docket No. 07-12001, Application Volume 1, Page 2.

being lower than anticipated when it was reviewed.) Determining what portions of these higher costs will be borne by ratepayers will need to be determined by the commission at different points in the life of the investment. Thus, the self-build facility raises particular types of inherent ratepayer risks that generally do not exist for resources supplied under PPAs. While it is possible to impose the same economic discipline on self-build offers as that applied to offers from third parties – such as through contracts that hold the utility to the price and performance terms that it assumed in its evaluations of self-build and third party offers – it is not the norm to do so.

Therefore, PPAs can provide inherent benefits to consumers by shifting these risks to suppliers.[67] Consequently, evaluations should aim to capture differences in the financial risks associated with different types of proposed agreements (e.g., PPAs and self-build proposals) and differences arising from particular contractual terms, such as the use of pricing terms dependent on fuel indices. Failing to account for risk mitigation will inherently disadvantage offers from third-party suppliers (who must account for such risks when making binding offers and contractual commitments) relative to self-build proposals from utilities (which tend to have such risks at least partially mitigated by the fact that regulatory review is based on actual rather than anticipated costs).

Procurements generally do not consider these risk mitigation benefits when evaluating competing supply offers. Several approaches could address these risks. First, similar to adjustments for debt equivalency, quantitative adjustments for risk mitigation could be developed.[68] As with debt equivalency, empirical understanding of these risks is limited, although, in principal, adjustments reflecting historical variances between initial and final cost estimates could be developed. Such adjustments may be no less accurate (and potentially more accurate) than current debt equivalency adjustments. We are unaware of any procurements that have utilized such adjustments to capture risk mitigation benefits.

There are other alternatives proposed to adjust for risk mitigation. One approach mitigates a portion of the supplier's risk (whether the utility or a third party) by allowing payments to vary depending on the level of market indices that capture these risks. Examples include the use of a natural gas price index to capture fuel prices risks, and use of a construction/materials cost price index (e.g., for steel and other materials) to capture construction cost risks.[69] Such approaches, however, do not completely resolve

[67] Further, incentives to control costs may be improved by assigning these financial risks to suppliers, who bear the full burden of these risks, rather than utilities, who share these risks with consumers. However, assuming that these risk transfers are accurately captured, supplier and utility offers should reflect the potential gains from these improved incentives.

[68] Boston Pacific Company. "Getting the Best Deal for Electric Utility Customer, A Concise Guidebook for the Design, Implementation and Monitoring of Competitive Power Supply Solicitations," prepared for the Electric Power Supply Association, 2004, p. 16.

[69] For example, the PacifiCorp 2012 RFP allows 40% of capacity payments to be tied to market indices, and up to 25% to be tied to the Consumer Price Index and up to 15% to be tied to the Producer Price Index for Metals and Steel Products. PacifiCorp, Request for Proposals, Baseload Resources, April 5, 2007, p. 39.

the inherent differences in risks between PPAs, self-build proposals and other forms of agreement. For example, these approaches typically do not fully mitigate project-specific risk that can be particularly daunting for certain types of projects (e.g., large, capital-intensive baseload plants). In addition, by shifting risks back onto consumers, indexing of payments may be undesirable in terms of other policy goals related to rate stability. As discussed previously, another approach to closing the gap between PPA and self-build risks is to shift development and capital cost risks from consumers to the utility by requiring that the utility agree not to pursue cost recovery for increases in construction costs beyond initial estimates. Thus, the utility would bear the risk of cost increases, which would then need to be reflected in its self-build offer.

### 7. Transmission

The transmission impacts associated with particular incremental resource additions can vary considerably from one proposal to another. These transmission-related costs can include the costs of connecting the facility to the transmission network, changes in overall system productions costs arising from congestion on the transmission system introduced by the operation of the new facility, and any costs associated with upgrades on the transmission network needed to enable the new resource to qualify for network service.

In comparing the value of incremental supply offers to retail customers, utilities therefore must not only examine the direct costs to purchase power supply but also the indirect costs arising from the manner in which an offer interacts with the utility's system dispatch and the impact (if any) of the output from the proposed resource on power flows on the utility's transmission system. As part of this analysis, competitive solicitations typically must involve evaluation of any transmission-system upgrades needed to deliver the proposed resource(s) to target customers. The costs of congestion and/or transmission upgrades necessary to achieve deliverability are an important consideration in resource procurements.

In the context of competitive power procurements, there are two important concepts associated with a proposed resource's deliverability:

1. Interconnection – This refers to the transmission connection between the generation facility and the existing transmission network.

2. Integration – This refers to any changes to the transmission system that may be necessary to enable new generation resources to meet load requirements and meet relevant reliability standards.

The costs of interconnecting generating facilities are relatively predictable. A bidder may be able to develop its own rough estimates to interconnect its facilities to the grid.[70] Typically, competitive procurements require the developer of the generation resource to bear such interconnection costs.[71]

By contrast, the costs to integrate fully a new resource into a system are likely to vary dramatically across systems, and across particular regions or nodes within a system. The costs may also vary depending on whether the resource is intended to supply firm or interruptible power under a variety of system contingencies. Typically a bidder will not have the detailed technical information necessary to calculate integration costs. Complex modeling of the transmission and generation systems is needed to identify what facilities are needed and then to estimate their costs. For example, in some cases, adding a new facility may delay the need for a planned transmission facility, and in other cases, the new generating resource may hasten the need for transmission upgrades. In the end, cost estimates for both interconnection and system integration enhancements rely on studies and engineering specifications developed by transmission providers, with these studies themselves taking time and money to accomplish. Because the cost of such system enhancements may differ between competing offers in competitive procurements, utilities should aim to find efficient and timely ways to obtain estimates of these costs.

Procurement design for incremental resources therefore must address several key issues related to transmission costs:

- **Identification of transmission-related costs to include in the review of alternative offers** – What might seem like a straight-forward issue in theory typically turns out to be quite complicated in practice. On the one hand, it is clear that if incremental offers for generation resources have different implications for transmission system integration costs, then utilities seeking to understand which offer provides the best value to customers should look not only at the direct costs associated with the generation offers, but also take into account their indirect costs (e.g., transmission system upgrades.) This should be

[70] Interconnection costs reflect the costs of the engineering and construction of transmission wires and other equipment necessary to connect new resources to the existing transmission network or to increase transmission capacity for re-powered facilities that will increase net output. Existing generation facilities or re-powered facilities not increasing net output typically do not incur any additional interconnection costs. The transmission company generally provides estimates of interconnection costs for all bids if bidders have not already obtained such estimates through prior requests for interconnection.

[71] Although there have been some allegations of bias in the interconnection cost estimates used to evaluate self-build or affiliate proposals, concerns about non-comparability of interconnection costs appear less serious than those related to integration costs. Further, it is likely easier for independent monitors to identify non-comparability for interconnection costs than for integration costs. (For example of such allegations, a report from the Colorado Public Utility Commission Staff noted that Public Service of Colorado estimated interconnection costs at $4.5 million for their self-build option while assessing interconnection costs of $60.5 million to other offers for similar coal-fired facilities. Staff of the Public Utilities Commission of the State of Colorado, "Report on Public Service Company of Colorado's 2003 Least-Cost Resource Plan," Volume 2, Docket No. 07M-147E, June 29, 2007, p. 26.)

the goal, but there will be important technical issues that must be addressed to accomplish this objective in a way that dovetails well with other features of the procurement process. First, in procurements for new resources, some specific generating project proposals may not have advanced far enough in the development process to be captured in studies by the transmission provider. The depth of the information available about congestion impacts, system upgrades, and facility cost estimates thus may vary significantly across offers. The planning studies and detailed technical analyses of such transmission issues are typically conducted by the transmission provider and can be costly and take time to complete. Therefore, a utility should anticipate the need for planning studies in advance of a procurement, and may find it useful to ask for appropriate studies to be performed as part of the transmission provider's transmission planning process (under FERC's Order 890).[72] The results of such studies can assist the utility in developing proxy cost estimates for integrating certain types of facilities located in different areas on the system.

- **Bidder information on transmission costs** – Although transmission-system integration costs are often an important component of a utility's economic evaluation of bids, such costs may not be well known to prospective bidders prior to submission of their offers. Without such information, bidders may not have a good sense of whether their proposals stand a good chance of winning a procurement. Given this uncertainty, utilities and transmission companies should attempt to provide bidders with information that will provide guidance about the relative costs of integration across alternative locations. Analyses performed by transmission providers when undertaking planning studies and specific network impact studies provide a useful source of information for utilities in their evaluation of the costs of integrating new generation into the system. These public processes and their results can also provide insights to market participants about possible cost advantages or disadvantages of offers located in one area or another. In addition, such information will help to explain (in part) the outcomes of the utility's evaluation of how individual offers interact with the utility's current portfolio of resources. Using this or other available transmission information, utility RFP documents should assist bidders by identifying to the extent possible such things as: any favored delivery points given the existing configuration of loads and generation in the network; locational information about a benchmark resource;[73] or information about likely integration costs.[74]

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[72] See, for example, FERC Order 890, Section V.B (Coordinated, Open and Transparent Planning), 2007, paragraphs 418-551; 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).

[73] For example, regulations in Florida require identification of details about the self-build option being pursued by the utility, including the proposed location. Such information is required to be accurate and any revisions to such information are to be provided to potential bidders in a timely fashion. Reliant Energy Power Generation, "Amended Complaint of Reliant Energy Power Generation, Inc. Against Florida Power and Light Company," Florida Docket 020175, May 17, 2002.

- **Bidder assumptions about who pays for system integration costs for winning offers** – In theory, the transmission-related costs associated with individual offers can be borne by either the bidder or the utility soliciting the offers. Most utility procurements require that bidders assume in their offers that they will absorb the costs to interconnect their facilities to the grid. But procurements for incremental resources have varied with regard to assumptions about for transmission upgrades needed to integrate the facility into the system. On the one hand, there are instances where procurements have required that bidders assume that they will directly have to absorb the costs of any incremental system upgrades associated with its project; in these instances, a reasonable bidder will construct a bid that allows for recovery of such costs as part of the purchase of power from the project. Other competitive procurements have incorporated a different assumption – that is, as long as a bidder's resource is located in or delivered into the utility's service area, the bidder should assume that it will not have to directly absorb system integration costs if the bidder's project is selected by the utility.[75] These two approaches can introduce quite different assumptions into the price of power supply bids. In the former type of bid, on-system transmission integration costs may be built into generation prices; in the latter, generation offer prices do not incorporate system integration costs and differences in transmission-cost implications of alternative offers are accounted for in the utility's evaluation of those offers. In the end, either way approach leads to a result in which the transmission costs associated with winning (and approved) offers will inevitably be born by consumers, whether it is through inclusion of such costs in suppliers' bids or through distribution utilities' charges to their retail customers to support transmission investment needed to deliver power to them. However, the size of these costs may not be the same under both circumstances. For example, suppliers facing the requirement that they pay for transmission system impacts, but with limited information useful to determining such costs, may add price premiums to their offers to account for such uncertainty.

- **Transmission study timeliness and cost** – Because transmission system planning studies can be time consuming, expensive and otherwise resource-intensive,[76] these studies have the potential to create a bottleneck in evaluation

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[74] For example, Georgia Power Company's 2010 RFP provided information on regions of the Southern Company's Control Area that are likely to have higher integration costs and more "difficultly meeting transmission firmness requirements." Georgia Power Company, 2010 Request for Proposals, March 22, 2006.

[75] Some procurements have attempted to level this playing field by treating all offers as though they have network status. For example, the Georgia Commission required Southern to treat all bidders as competing network resources in its 2005 RFP. ("... in order to mitigate the relative size of Southern and to increase alternative supplies, the Commission required Southern to treat unaffiliated entities as if they are competing network resources in meeting load and load growth." Calpine Corporation, "Protest and Alternative Request for Hearing of Calpine Corporation", FERC Docket No. ER03-713-000, April 29, 2003.)

[76] The cost and time of a full system impact study may place real constraints on how these studies are used in the evaluation stage of a competitive procurement process. Most procurements rely upon a preliminary

procedures unless care is taken by utilities to plan their requests to transmission providers in ways that support competitive procurements. The time required to complete such formal planning studies has led some utilities to develop less costly and quicker approaches to estimate the cost of system impacts and needed transmission investments for use in evaluating procurement supply offers.[77] Such approaches help to identify the relative cost implications (for transmission and dispatch) of various resource options within a reasonable time frame; and it reduces the number of formal studies that eventually need to go through the transmission provider's formal transmission planning studies and/or facility review processes.

- **Comparability of transmission-related costs** – Estimates of system integration costs should be developed in ways that do not introduce unfair or undue discrimination among offers from third-parties, affiliates and the utility's self-build proposal. The complexity and "black box" nature of system impacts studies raise many challenging issues for ensuring such comparability.[78] In situations where the utility's competitive procurement team is reviewing offers from third parties, the utility's affiliates and any self-build proposals from the utility itself, an independent evaluator should review the comparability of any methodologies and the basis for cost estimates prepared by the utility team to review the offers.

For some types of resources, such as wind power, procurements have also had to address the "chicken and egg" problem of coordinating the timing and commitment to large transmission investments necessary to interconnect and integrate new resources on to the grid. Wind resources typically require both large interconnection investments, due to their remote locations, and potentially large integration investments to avoid regulation and loop flow problems that may arise due to sudden power variability.[79]

The complexity of these various transmission-related issues suggests that competitive procurements should include clear ground rules about the transmission-related

transmission analysis for early stages of the evaluation process, both to lower the cost the evaluation and complete these initial assessments in a timely fashion. Once the initial evaluation stage has identified a short-list of the most competitive bids, full system impacts studies are then performed for bids on this short-list. For example, see the Georgia Power 2009 RFP (Accion Group, "Report to the Georgia Public Service Commission on the Georgia Power Company 2009 RFP," p. 27.) Also, the Entergy Louisiana Little Gypsy 3 procurement (Potomac Economics, "Independent Monitoring of the Evaluation of Proposals for Entergy Long-term Supply-side Resources, Solid Fuel Final Report,", September 2007).

[77] Some procurements have considered the use of initial preliminary estimates in later stages of evaluation should system impacts studies be delayed. For example, see Benson, 2007, p. 40.

[78] For example, see, Accion Group, "Report of the Independent Evaluator, [Georgia Power] 2010 and 2011 RFPs, Re: Draft RFP Documents," November 21, 2005, p. 4.

[79] See, for example, "Oregon Department of Energy's Reply Comments on Bidding Guidelines," Oregon Docket No. UM 1182, October 21, 2005. Also, see the approach adopted by the California ISO to support interconnection and integration of "energy resource areas," such as areas with the potential to develop wind resources. 119 FERC ¶ 61,061, Order Granting Petition for Declaratory Order, California Independent System Operator, Docket No. EL07-33-000 (Issued April 19, 2007).

assumptions to be used in preparing all bids and evaluating all offers (including self-build proposals). As a result of the complexity of these transmission issues, oversight by independent monitors may be important to ensuring bidder confidence and enforcement of procurement rules.

### 8. Other Non-price Criteria and Bid Requirements

While some "non-price" price criteria, such as transmission impacts or certain financial risks, may be quantifiable in dollar terms, other non-price factors that impact the value of a competitive offer may be difficult to measure on such terms. Such "non-monetized" criteria may include factors such as development risk, contribution to the overall fuel diversity of the utility's portfolio, environmental benefits, and operational flexibility.

There is substantial variation across procurements in which non-price factors are considered, and which non-price factors should be introduced via non-monetary metrics or other subjective approaches. (Appendix D provides details on the criteria considered in selected competitive procurements and whether these criteria are evaluated in monetary or non-monetary terms.) Some procurements include few non-monetized criteria, while others include many. There are obvious but nonetheless difficult tradeoffs in reliance on many of these criteria. While non-monetized factors may reflect important policy or service objectives, they also may increase the subjectivity of evaluation outcomes and increase the opportunity for preferential treatment of the utility's self-build or affiliate offers.

The means by which non-monetized criteria are evaluated and compared also varies significantly. An important issue is whether non-monetized factors are used as threshold eligibility requirements that proposals must meet in order to proceed to further evaluation and possible selection. Because such threshold criteria serve to leave some offers outside the door while others are able to proceed, these criteria must be chosen with care. In practice, their use is generally limited to factors that are in some way essential to a proposal's success, such as technical requirements (e.g., location of the resource on the system) or minimum supplier credit-worthiness. Winnowing out potentially valuable offers from consideration because of non-essential considerations can undermine the goal of providing the "best" resource options to consumers. To the extent they are used, such eligibility criteria should be stated explicitly in RFP documents to ensure that suppliers have an opportunity to fulfill such criteria and/or determine that it is not worth expending resources to prepare a bid.

For offers meeting these eligibility requirements, the further assessment of non-monetized criteria can take many forms. These assessments may range from evaluations that explicitly score and weight identified criteria to those that simply list non-monetized criteria that will be considered by the utility using their discretion. These alternatives balance several factors. Explicit scoring and weighting provides transparency to bidders, independent monitors and commissions, but may lead to evaluations that constrain the utility's ability to exercise appropriate judgment about these non-monetized criteria. Choices made by firms every day reflect these types of judgments about non-monetized factors, similar to the types of judgments made by homeowners when choosing a construction contractor. While procurements that simply identify relevant non-monetized criteria provide evaluators with flexibility in how such factors are considered, however, they may provide the utility with a subtle and difficult-to-trace way to exert improper preferential treatment for or against certain supplies. For example, in some circumstances, bids have been eliminated in the initial review or short-list stage due to concerns about the viability of the resource given information on: project schedules; engineering, finance and permitting status; credit-worthiness; and other considerations.[80] In particular where utility self-build proposals or affiliate offers are involved, regulators should scrutinize the use of non-monetized criteria and expect to rely on on-the-ground oversight from an independent monitor to help ensure that such criteria are not used to improperly exclude certain offers from consideration.

[80] For example, several offers in PacifiCorp's RFP that lead to a proposed self-build were eliminated due to such factors. Oliver, Wayne. "Direct Testimony of Wayne Oliver on Behalf of Division of Public Utilities," Docket No. 04-035-30, DPU Exhibit 2.0., September 27, 2004, p. 21-22.

# VI. PROCUREMENT OF FULL REQUIREMENT SERVICE

## A. OVERVIEW OF FRS SUPPLY PROCUREMENTS

Utilities in states with competition for retail generation service typically do not rely upon incremental resource procurements. Instead, these utilities generally procure so-called full-requirement service ("FRS") products. In these states, utilities retain certain service obligations to provide supply for certain retail customers and yet may have no (or insufficient) generation resources to supply these customers' needs. This is true in states where the utilities divested most if not all of their generation assets and long-term supply agreements as part of industry restructuring. In these states, commissions have typically developed policies affecting the design and implementation of FRS procurements, which often reflect requirements embedded in each state's electric industry restructuring legislation.

In FRS procurements, suppliers submit offers to provide all electricity services for a standardized block (slice, or share) of the distribution utility's customer load. By standardizing the components of FRS and the terms of FRS contracts, price becomes the only factor differentiating offers from potential suppliers. Thus, the utility selects the offers with the lowest prices, after identifying sufficient blocks to supply customers' demand requirements. In most cases, the utility is the contracting agent, and in effect passes through the cost of buying power supply from the selected FRS contractors.[81]

By eliminating subjectivity and complexity from the evaluation of offers, the price-only nature of FRS procurements provides many benefits. For example, in those FRS procurements involving highly structured auctions (such as New Jersey, described Box 3), minimum procedural safeguards are needed to protect against self-dealing; the safeguards relied up are an independent auction manager, code-of-conduct requirements, and various monitoring procedures to deter outright bid rigging. Because price is the only factor affecting the choice of winning offers (assuming all bidders have met eligibility requirements), the evaluation process leaves little opportunity for improper assessment of offers. Consequently, participation of unregulated generation affiliates does not generally require additional safeguards to protect against improper self-dealing.

[81] The particular components of these products vary across utility service areas depending on the particular products offered in wholesale markets administered by Regional Transmission Organizations, transmission tariffs, and state requirements on electric generators (e.g., renewable portfolio standards). In the case of New Jersey, for example, full requirements service includes fifteen products from various markets. There are some deviations from these generalizations. Some commissions have excluded certain products from FRS contracts due to pending regulations that increased the uncertainty of the associated costs for suppliers.

**Box 3**

**New Jersey's Procurement of Full Requirements Service (or "Basic Generation Service")**

As part of its restructuring legislation, New Jersey's major electric distribution utilities undertake competitive procurements for the provision of electricity services to customers that continue to take Basic Generation Service ("BGS") from the utility. Utilities procure BGS supply through auctions using a "descending-clock" mechanism. In this type of auction, the utility posts a price and suppliers submit offers for the share of the utility's customer load they are willing to supply at that price. If there are more offers for supply blocks than are needed, the auction manager lowers the price in succeeding rounds of bidding until bidders offer just enough power to satisfy the utility's load requirements. Binding agreements are signed shortly thereafter, which allows the bidders to develop financial positions to hedge the financial risks of their BGS supply contracts. Winning bidders must also post sufficient collateral to mitigate the risk of defaulting on their supply commitments to the utility. Auctions are held at the same time for all affected utilities in New Jersey, although each utility procures supply for its own customers. The rules for these auctions have been relatively consistent since the first auction in 2001.

Bidders must meet certain eligibility requirements, but do not need to own generation facilities. Suppliers are responsible for needed components of supply (including energy, baseload energy, capacity, renewable credits, ancillary services, and so forth). And it is up to the supplier to determine over time what mix of resources (and what combination of physical supply contracts or assets and financial arrangements) to rely upon to service the BGS supply contracts.

The auction starts with all potential bidders submitting indicative bids prior to the auction to help determine appropriate starting prices. The auction occurs over one to two days, with new rounds occurring at relatively frequent internals within the auction period. Various bidding rules are imposed to improve price discovery and mitigate against strategic manipulation intended to raise auction prices. For example, bidders that chose not to offer supply in one round are prohibited from bidding in subsequent rounds. A variety of supply blocks (for different customer classes (e.g., a commercial supply product) and for different utilities) are auctioned in parallel, and bidders are allowed to shift their bids between product auctions over the course of the auction, until it closes. Affiliates may offer supply into the BGS auctions.

Currently, three-year contracts are procured for one-third of each utility's load in each year. Pricing terms vary depending on the type of customer being supplied. Supply for residential and retail customers is set at a fixed price over the three-year contract, while supply for customers with loads exceeding certain thresholds is set at a price that varies by hour.

The process is overseen by an independent auction manager/monitor hired by the utilities. The auction manager must approve the auction results in order for them to be forwarded to the Board of Public Utilities ("BPU"). The BPU has two days to approve the results of the process. In total, the auction takes about six days from the time the auction is held to the time when contracts are signed and approved.

The design of FRS procurements also has important implications for the distribution of financial risks associated with providing supply. By requiring that each supplier construct its offers and then commit to arrange for and manage all aspects associated with supplying electricity for a share of the utility's entire customer load, the utility effectively shifts important financial risks from itself to the competitive suppliers. One type of risk is the portfolio risk associated with constructing whatever mix of short-, medium- and long-term financial and physical arrangements the supplier believes are necessary and appropriate to service the contract. Another type of risk is the volumetric risk that arises from uncertainty about the size of customer load; this risk is particularly sensitive to the migration of customers to and from the utility's service territory.

Experience with FRS procurements varies across states depending on the implementation of industry restructuring, and particularly the duration of transition rate caps. While some states (e.g., New Jersey, Maine, Massachusetts) have many years of experience with FRS procurements, many other states' experiences are significantly shorter, particularly where transition rate caps and associated supply contracts have limited supply procured through FRS procurements.[82] Despite this variation in experience, because of many common design elements across states, existing experience provides a good basis for developing lessons about FRS procurements.

Most FRS procurements follow a common format: first, information about FRS products, the procurement approach, and a procurement schedule is released to bidders in advance of the actual date when offers are to be submitted. Because of experience with past FRS procurements, few recent changes in rules or products between procurements, and the opportunity to ask clarifying questions, these procedures are generally well understood by bidders in advance of submitting their offers. Next, bidders submit offers in accordance with specified procedures. Utilities then select winning bids, and regulators generally approve results within a short period of time. As an example of an auction style of FRS procurement, Box 3 describes the basic elements of FRS procurements in New Jersey.

Some states with retail competition are undertaking or considering policy changes with potentially important implications for competitive procurements. For example, several states have undertaken or are considering requirements that utilities develop integrated resource plans to identify potential resource deficiencies.[83] Some options for addressing resource deficiencies potentially alter current reliance on FRS procurements for procuring supply. Box 4 summarizes some of the revisions being undertaken or considered in different states.

Because these changes may lead to increased reliance on incremental resource procurements, lessons from such procurements as used by vertically integrated utilities may be valuable for providing insights into design issues. These changes may also have implications for future FRS procurements. So far, the relatively simple structure of FRS procurements arises because utilities procure all customer supplies through these procurements. However, in the future, procurements processes will need to accommodate both of these activities. For example, a utility that is supplying peaking resources itself will also be procuring FRS products in some form. At a minimum, such

[82] In many states that restructured their electric industries to allow for retail competition, customer choice and encouragement of divestiture of utility assets, the transition periods involved situations where distribution utilities met their customers' supply requirements through initial long-term "transition supply" contracts. This was true, for example, of Illinois, Massachusetts, Pennsylvania, and Rhode Island, among others. The presence of these multi-year supply contracts accompanied by transition rate periods meant that distribution utilities did not need to procure other supplies for many years. As these contracts have expired with the end of transition rate caps, distribution utilities have had to rely on FRS procurements to procure all supply for their customer.

[83] Delmarva Power & Light Company's Delaware IRP Update, March 5, 2008. Delaware PSC Docket No. 07-20. Integrated Resource Plan for Connecticut, January 1, 2008.

changes may lead to a re-definition of the utility's need for supply beyond its own assets and agreements, may shift some volumetric risk back onto rate payers, and re-introduce certain portfolio management responsibilities to the utility.

Some elements of the design of FRS procurements can have important implications for their success in terms of achieving an efficient and timely process, encouraging supplier participation, and developing the best offers for consumers. We discuss these further below.

## B. PRODUCT DEFINITION – DIFFERENT TYPES OF FULL REQUIREMENT SERVICE SUPPLY

How FRS supply products are defined is an important means by which regulators may influence the consequences of FRS procurements for ratepayers. The early FRS procurements often sought to procure all service for all customers through a single procurement, so that consumer rates tended over time to closely follow changes in wholesale market prices. In recent years, regulators in many states have attempted to mitigate the resulting rate volatility arising from FRS procurements in a number of ways.

One approach to mitigate price volatility is to increase the duration of full requirements contracts. Procuring supply through longer-term contracts (e.g., two or three years) reduces price volatility by reducing the frequency of power purchases. A second approach to mitigating volatility is to pool or average procurements over time by procuring only a portion of load in each auction. By staggering procurements, customer prices at any point in time are based on a blend or rolling average of prices from different points in time.[84] Finally, volatility can be mitigated through the pricing terms offered to customers. Supply agreements (and thereby customer rates) can be set based on flat, non-varying rates over the duration of the agreement, or designed to vary by hour, day, or season in a predictable fashion over the agreement's duration.

Regulators' decisions about mitigating price volatility often seek to balance potentially competing policy tradeoffs. On the one hand, reducing rate volatility may shield consumers from certain undesirable economic consequences. However, shielding consumers from price volatility may inadvertently slow the development of competitive retail markets in these retail access states, as well as preventing customers from seeing the true cost of supplying power. This latter effect blunts price signals that might otherwise better inform customer decisions about using electricity or reducing demand.[85]

[84] Mixing contracts of different duration allows a blending of long-term contracts that stabilize prices and shorter-term contracts that may create fewer stranded cost and cost recovery risks for the utility.

[85] In states where competitive retail options exist, customers can mitigate rate volatility, and thereby avoid facing current market prices in all hours, by contracting with competitive retail suppliers offering fixed price service. In this case, however, the choice is made by the consumer, rather than the regulator.

**Box 4**

**Elements of Evolving Regulatory Frameworks in States with "Hybrid" Full Requirements Service Procurements**

**Utility participation in resource procurements** – In Connecticut, new legislation requires that electric utilities obtain certain new generation resources. Connecticut Light and Power, and United Illuminating were required to submit a self-build proposal for new peaking capacity. Third party suppliers were also permitted to make offers for peaking capacity. The legislation specified that suppliers be compensated based on a traditional "cost plus" regulatory model. In Ohio, a recently enacted law (127 SB 221) preserves the right of customer choice previously established in the state and retains the utility's standard offer requirement. The law allows a utility to propose a market rate option ("MRO") under some circumstances (e.g., existence of forward price benchmarks, and an RTO with a market monitor having certain roles and responsibilities), or an "electric security plan" (that allows the utility to undertake its own generation investment). If approved by regulators, the MRO must use open competitive bidding for establishing the suppliers and prices of MRO service; the law sets forth findings the Commission must make in order to approve the results of the competitive solicitation.

**Utility procurement of resource portfolio** – In Delaware, Delmarva power was required by legislation to pursue long-term supply contracts as a part of an IRP process. Delmarva is now in the midst of procuring a portfolio of new peaking generation resources, wind power resources, demand-side management and energy efficiency programs, short- and long-term bilateral contracts, and market purchases. State agencies have recently issued rules on utility portfolio development and management, and the terms of individual procurements.

**Long-term contracts** – A number of states are considering or have allowed utilities to enter into long-term contracts to provide supply for their customers on standard offer service. In Maine, for example, regulators have directed utilities to enter into long-term contracts, with a particular focus on capacity resources. Massachusetts recently passed a new "Green Communities Act" (July 2008) with requirements that utilities enter into long-term contracts with renewable suppliers for up to 3 percent of the utility's load.

**Government involvement in procurements** – The recently enacted Illinois Power Agency Act (2007) calls for the formation of a state agency with the power to construct and operate power generation facilities, procure supply through contracts with market participants, and sell power "at cost" to customers. Retail service provided by the state power agency would not replace standard offer service provided by the utility, but would offer customers an "at cost" alternative to standard offer service and service offered by existing competitive retail suppliers.

**Procurement of renewable and/or alternative energy attribute credits** – Under policies adopted by New York regulators, the state uses a hybrid approach to implement its renewable portfolio standard requirements. Electricity customers pay for renewable energy credits through a non-bypassable payment on their utility bills. The funds collected are used by the New York State Energy Research and Development Authority ("NYSERDA") to purchase renewable energy credits ("RECs") from renewable power suppliers; a single-clearing price auction process is used to make awards and sign contracts for different quantities of RECS for different contractual durations. New York's utilities have recently been directed to pursue renewables more directly, as well. In Pennsylvania, utilities are responsible for compliance with the state's Alternative Energy Portfolio requirements. PECO Energy has been authorized to use a competitive process to procure and bank Alternative Energy Credits ("AECs").

As a result of these competing goals and particular customer attributes, regulators and utilities often design standard-offer products – and the procurement of supply for them – to meet the different needs of different customer classes. Products for residential and small commercial customers are typically designed to minimize price variation through use of overlapping, two- to three-year contracts with fixed prices. By contrast, products for larger customers (i.e., customers above some pre-determined load threshold) generally follow market prices through single, short-duration (e.g., three-month) contracts with prices that vary by month or hour. Regulators appear more willing to shield smaller customers from market volatility given the fewer number of competitive suppliers available to them and, potentially, other policy concerns. Appendix E provides examples of different types of FRS products currently being procured in different states.

Utilities and their regulators may choose to mitigate certain risks facing suppliers in order to encourage participation in FRS procurements and avoid high risk premiums associated with particular regulatory uncertainties. For example, multi-year contracts may create risks for suppliers when significant policy changes loom on the horizon, such as now may exist with climate change legislation, or the adoption of a new capacity market in the relevant Regional Transmission Organization region. Given such uncertainties, some states have eliminated certain products from those procured as a part of FRS procurements, including potential renewables requirements and capacity market products.[86] Some states have even attempted to limit supplier's volumetric risk by placing limits on the extent to which the supplier's load obligations can shift over time give potential customers' migration.[87]

## C. PROCUREMENT APPROACH – AUCTION AND REQUESTS FOR PROPOSALS

FRS procurements have been implemented through either single-price auctions, such as the descending-price clock auctions used in New Jersey (described in Box 3), or RFPs with sealed bid offers. To date, descending-price clock auctions have been used in several states, most notably, Illinois in addition to New Jersey, while other states rely on sealed-bid RFPs.

Under a sealed-bid RFP, bidders provide a single, binding, sealed offer that specifies the quantity they are willing to supply and the price demanded to deliver that supply. Utilities select the lowest-cost supply from among these offers and the price paid to each supplier reflects that supplier's offer price ("pay-as-bid"). By contrast, under descending-price clock auctions, suppliers submit multiple offers until the market clears, and suppliers are all paid the same price (the "single clearing price".)

In principle, clock auctions produce lower prices by promoting price discovery through multiple rounds of bidding and eliciting bids that better reflect underlying economic

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[86] For example, in the past, Maryland utilities have exempted suppliers from future renewables requirements and Massachusetts utilities have exempted suppliers from uplift and capacity requirements. Maryland Utilities, "Maryland Utilities' Request For Proposals for Full Requirements Wholesale Electric Power," Pre-bid Conference, December 12, 2006. See also, Competitive Procurement Survey Response from Massachusetts.

[87] For example, starting in June 2008, power (MW) supply obligations under Maryland utility FRS contracts are capped at a fixed quantity. Any increase in supply obligation beyond this cap as a result of customer migration or other factors is the responsibility of the utility. Maryland Utilities, 2006, p. 63-65.

costs.[88] Although they impose greater cost and complexity on administrators and market participants, the overall cost of implementing such auctions is likely to be modest relative to the total value of services procured in these auctions. While clock auctions provide better performance in principal than pay-as-bid RFPs, empirically demonstrating the magnitude of this benefit (if any) is difficult.

Under either type of procurements, bidders may be required to submit preliminary or "indicative" bids prior to the actual RFP or auction. These indicative bids may be used to determine initial prices in clock auctions and provide information to commissions useful for performing a preliminary assessment of likely market prices and the competitiveness of market response.

Such information may also be used as a part of procedures designed to protect against unanticipated, adverse procurement outcomes. For example, Maryland has developed a price anomaly procedure, under which higher-price bids may be rejected if average prices exceed thresholds designed to reflect current market conditions.[89] In other states, the commission has the authority to delay a procurement in the event of unforeseen events that may undesirably elevate market prices (e.g., hurricanes.)[90] Use of these procedures has potential implications for other aspects of procurement performance by, for example, increasing supplier uncertainty and leaving the utility out of compliance with other state regulations. For example, Massachusetts utilities would be unable to fulfill state requirements that they post rates in advance of providing service to customers if the result of a procurement were rejected and the utility had to rely entirely on spot markets to procure supply.[91]

## D. OTHER ELEMENTS OF FULL REQUIREMENTS SERVICE DESIGN

### 1. Bidder Eligibility and Collateral Requirements

Because they are designed to select supplies on the basis of price alone, FRS procurements rely upon eligibility and collateral requirements to ensure that potential winning suppliers are able to fulfill their supply obligations. In particular, eligibility requirements generally require that suppliers demonstrate their credit-worthiness. In effect, these requirements attempt to ensure that all eligible suppliers have the means

88 Cramton, Peter et al., "Auction Design for Standard Offer Service." Working Paper, Charles River Associates and Market Design, Inc, 1997.

89 Under the price anomaly procedure, the commission's consultant, with input from its staff, develops a price anomaly threshold ("PAT"). If the load weighted average price from all winning bids exceeds this PAT, then the highest priced bids are dropped until the average price is at or below the PAT. Any deficiency in supply from dropping high priced offers is made up at subsequent or reserve procurements. Maryland Utilities, 2006.

90 Public Service Commission of the State of Delaware, Order No. 7053.

91 Competitive Procurement Survey Response from Massachusetts.

and incentives to deliver FRS supplies, along with insuring the utility and its customers against financial loss in the event of supplier default. In addition, suppliers are typically required to demonstrate their ability (and qualification) to participate in the relevant wholesale electricity markets needed to provide FRS supplies. Physical ownership of generation facilities is typically not a requirement.

Bidders generally are required to provide collateral in support of non-performance of the contract when offers are submitted. The level of collateral required is pre-determined based on the quantity of supply offered, and may also depend on the supplier's own credit-worthiness.[92] The forms of credit acceptable to utilities varies, with some utilities requiring cash or letters of credit, and others allowing bidders to propose alternate forms. Because fulfilling these requirements may be costly, it is important that collateral requirements are set to balance the utility's need to insure against default against the deterrence such requirements may have on supplier participation.

### 2. Independent Monitors [93]

Independent monitors may play several important roles in FRS procurements. First, they may review RFPs and related materials, oversee distribution of procurement information, and participate in public workshops to ensure that participants receive sufficient information to allow them to compete effectively. As information such as data on customer loads and migration is critical to suppliers' ability to submit competitive offers, ensuring that information is provided in a thorough and timely fashion is important to procurement success. Second, IMs typically monitor all procurement phases to ensure a fair and objective process. While the evaluation process in FRS procurements is fairly straightforward, IM oversight nonetheless helps to provide assurance to the utility, regulators, suppliers, and consumers that there are appropriate safeguards to prevent inappropriate bidding behavior or preferential treatment in selection. IMs, or other consultants hired by commission staff, may also provide an assessment of the procurement's competitiveness (e.g., number of bidders and quantity of supply bid), whether the procurement has occurred during a spike in wholesale market prices, or whether other "anomalous" events have adversely affected procurement outcomes.[94] The monitor may provide feedback on potential modifications

[92] For example, see, Maine Public Utilities Commission, "Request for Proposals to Provide Standard Offer Service to Central Maine Power Company's Residential and Small Commercial Customers," October 9, 2007.

[93] In an FRS procurement in which price is the only factor used in selecting bids, the independent monitor has sometimes been called an "independent auction manager" or an "independent evaluator." Although there are important nuanced differences among their functions, the essential feature is the involvement of a party who is neither an employee of the utility nor of the regulatory agency, with specific responsibilities relating to the competitive procurement. In Illinois' FRS auctions, the Auction Manager was responsible for designing and implementing the descending clock auction on behalf of the utilities. Her responsibilities included communications with bidders, conduct of the auction, monitoring the status of offer prices and participation, identifying the award group, and reporting to the Illinois Commerce Commission. Thus her role included monitoring the process, managing the auction, and evaluating the process and its results.

[94] Maryland Utilities, 2006; Public Service Commission of the State of Delaware, Order No. 7053.

to procurement procedures. In some cases (e.g., Illinois), the auctions were actually run, or managed, by the independent monitor (in this case, called the auction manager, selected by the utility).

Use of IMs in FRS procurements varies across states. In some states, procurements are reviewed by IMs that provide formal reports on procurement results to state commissions.[95] Other states do not use IMs and rely on oversight provided by the PUC to ensure the integrity of the procurement process.[96]

### 3. Timing and Commission Approvals

Procurement timing is particularly important for creating positive incentives for supplier participation and avoiding additional costs that may raise the prices of supplier bids. FRS procurements generally aim to minimize the time between submission of bids and awarding of contracts. This serves not only to minimize suppliers' financial risks associated with potential changes in market conditions that may occur after they submit their bids, but also to minimize the risk premium that suppliers would likely include in their offer to cover their exposure to these market risks. Because of the price-only nature of FRS procurement, evaluation of offers by utilities and approval of results by commissions can generally be competed quite quickly. All FRS-procurement states that we reviewed, with the exception of Maine, issued finalized procurement decisions within a five day period, and some finalized these decisions in as little as one day.

### 4. Confidentiality

Policies to protect the confidentiality of bidder information reflect a balance between (a) the benefits of transparency about the market's performance, and (b) protection of valuable and commercially sensitive bidder information. Commission policies on release of bid information typically involves bidder identities, quantities of offers (bids amounts), and the price level of winning bids.

Supplying actual bid information from the bidding rounds themselves raises a number of concerns. First, such information may reveal valuable information about bidding strategies. Second, such information may raise suppliers' costs of hedging the financial risks to supply FRS, and thereby the price of their FRS offers, by alerting financial market participants to their need for financial hedges. Potentially adverse consequences of these policies can often be mitigated through careful design. For example, release of information about winning bidders can be delayed to avoid raising the costs of financial transactions made after securing the FRS contract. In practice, policies regarding release of supplier information vary across utilities. For example, Delaware utilities only release information from its RFP procurements that reveal averaged bid prices and bid

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[95] For example, Delaware, Maryland, New Jersey, and Washington, D.C.

[96] For example, Maine and Massachusetts.

ranges, while New Jersey utilities release information on market-clearing prices and winning bidders for each utility.[97]

[97] Response to Survey by Janis Dillard, Delaware PSC; "The 2006 BGS Auction Results," <http://www.bgs-auction.com/documents/2006_BGS_Auction_Results.pdf>.

# VII. CONCLUSION

Competitive procurements for retail electricity supply have been used for many years in different states. More than forty percent of the states now rely on formal policies and rules for procurements, while regulators in many other states encourage use of competitive procurements by utilities in determining which resources to add to their mix of retail supply.

Where regulators have committed to relying upon competitive procurement approaches as a means to help identify the "best" resources needed to meet the needs of the utility's customers, the process should be designed and implemented so that it reflects the following criteria (and is generally viewed as being consistent with them):

- fair and objective;
- designed to encourage a robust competitive responses from market participants with creative responses from the market;
- based on evaluations that incorporate all appropriate and relevant price and non-price factors;
- efficient, with a timely selection process; and
- supported by regulatory actions that positively reinforce the commission's commitment to the other criteria.

While the use and design of procurements continues to evolve, there is a growing body of experience that provides a relatively clear set of issues that commissions and utilities should consider when they design competitive procurements to suit the industry structure and regulatory norms in their states. The checklists (in Tables 2 and 3 in the Executive Summary) and discussions of individual issues provided in this report lay out regulators' key decisions and options for the design of competitive procurements, the tradeoffs they must assess when choosing among these options, and the other lessons learned from past procurement experience.

While past experience provides valuable lessons for the design of future procurements, there are still many issues that require further development as regulators consider expanding the use of competitive procurements and using these procurements to develop the types of new resources that will likely be needed to meet future electricity needs in a manner consistent with other environmental and policy objectives. Notable among these issues are how regulators will incorporate the efficiency benefits of market forces in situations where capital-intensive resources and advanced technologies are needed to satisfy such long-term electricity requirements in a carbon-constrained economy. This merits continued attention from regulators and members of the industry.

## APPENDIX A – INDEPENDENT MONITOR ACTIVITIES AND ROLES

The range of potential activities in which an IM might participate is extremely broad, spanning from the initial stages of procurement design to its final approval. In these interactions, the IM may assist commission staff or perform independent monitoring in the following areas:[98]

- Review and comment on completeness of proposed RFP materials and conformance with relevant requirements;
- Review and comment on proposed evaluation methods and assumptions;[99]
- Oversee written and verbal communications between the commission, its staff, potential bidders, and the utility (including its evaluation teams, transmission evaluation teams, and unregulated generation affiliates);
- Monitor and in some cases, moderate utility public workshops;
- Identify and assist in the resolution of potential disputes arising between parties involved in the procurement;[100]
- Provide feedback to the utility and commission on different elements of the procurement process;
- Validate utility self-build (prior to bid submission);[101]
- Review and validation of models and assumptions used in evaluating offers;
- Management of submitted offers, including initial review of submitted offers and "blinding" of offers in conformance with relevant requirements;
- Oversee of the utility's evaluation process;
- Independently evaluate submitted offers;
- Independently assess portfolios of offers according to broader planning goals;[102]
- Oversee negotiations with bidders; and
- Report on procurement process, results, and lessons learned to regulators.

[98] Other states providing detail on IM roles include Georgia (Georgia Code 515-3-4-.04)

[99] Utah Administrative Code, R746-420 requires such reviews, and procurements in Oregon have included such reviews. For example, see Boston Pacific Company and Accion Group, "The Oregon Independent Evaluator's Assessment of PacifiCorp's 2012 RFP Design," April 13, 2007.

[100] Utah Administrative Code, R746-420.

[101] Utah Administrative Code, R746-420.

[102] Public Utilities Commission of Colorado, Emergency Rules Amending the Commission's Electric Resource Planning Rules, Decision No. C07-0829, September 19, 2007.

## APPENDIX B – CREDIT REQUIREMENTS

This appendix provides additional details on several aspects of how credit requirements are treated in competitive procurements, including:

- Rationales for the level of credit guarantees and/or collateral requirements;
- Means of reducing the cost of credit requirements; and
- A summary of credit requirements in illustrative procurements.

### THE LEVEL OF GUARANTY OR COLLATERAL REQUIREMENTS

Financial guaranty or collateral requirements should be related to the actual financial consequences to utilities of suppliers' failure to perform under the terms of the contract. The risk of non-performance arises because of the potential for supplier bankruptcy or default, and the potential that it may not be in the supplier's financial interest to fulfill the terms of the contract. PPA agreements typically impose penalties on suppliers in the event that they cannot (or do not have sufficient incentive to) fulfill agreement terms, and provide financial compensation to the utility for the potentially higher cost of replacing lost power. To ensure that suppliers have sufficient financial resources to fulfill these terms, they are required to provide a financial guarantee that such funds are available.

(While less often the focus of scrutiny in procurements, some suppliers may seek to require that utilities (as buyers) put up some form of financial assurances that the utility will also perform under the terms of the contract. Reasons of commercial symmetry and fairness may warrant such reciprocal financial assurances, which may include conditions (e.g., a utility credit rating falling below a particular point) under which the utility needs to post forms of financial guaranty or credit to support their performance under the contract.)

Collateral requirements for power suppliers should reflect the likelihood that they will fail to perform and the financial consequences for the utility in the event of the seller's non-performance. Estimating the financial cost of non-performance will depend on many factors, such as the market alternatives available for replacing lost power, the type of supply being replaced (e.g., peaking or baseload), the value of the contract that remains to be fulfilled, and likely payments received through litigation of the contract. Some of these risks can be directly addressed in the terms of the contract (e.g., size of penalties for non-performance), with collateral in place to support the agreement.

In some procurements, bidders have questioned the level of credit requirements as unrelated to the actual non-performance risks facing utilities.[103] Regulators should attempt

[103] For example, see Louisiana Public Service Commission Staff, "Preliminary Comments of the LPSC Staff on the Draft RFP," Southwestern Electric Power Company, 2005 RFP for Intermediate and Long-term Resources, p. 3, 8-9.

to gauge whether the particular level of credit requirements is warranted or are so strict as to inappropriately stifle a robust level of participation from the market. The implication of credit requirements on supplier cost structures is not particularly well understood. For example, alternative assessments of impact of credit requirements on total project costs for recent California procurements suggested that such requirements raised costs as much as nine percent and as little as two percent.[104]

The level of financial guarantee necessary to address the risk of non-performance may change over the course of the procurement and the term of the contract. For example, during the bidding and evaluation phase of an incremental resource procurement, utilities may face some risk that a supplier's offer is not sufficiently developed and financed to be credible. Such offers may lead to unnecessary administrative costs and potential failures to develop resources in a timely fashion if they lead to procurement delays. Utilities often require a bid deposit or fee when offers are initially submitted, and then impose additional requirements for offers that are selected for the short-list. Regulators should be aware that initial bid deposits can act as a barrier to entry for certain suppliers – some of whom may submit desirable offers in certain procurements, such as those for demand side management services or renewable resources.[105]

Suppliers may also be required to post financial security during the time between the awarding of the contract and the time when delivery begins. Such requirements may be needed in the event that facilities under development do not meet contracted schedules, if the project defaults, or if the facility does not meet technical specifications (e.g., heat rate guarantee, availability levels, or emissions rate). During the period when suppliers are obligated to deliver power, many solicitations use a mark-to-market approach to set collateral requirements, in which the amount of required collateral changes in proportion to the utility's expected financial loss if it needed to obtain replacement power. However, the actual procedures by which mark-to-market approaches are implemented vary substantially across procurements.[106] Additionally, contract provisions allowing for penalties in the event of poor supplier performance (e.g., availability below acceptable target levels) may be able to address directly various risks, so that collateral can be focused more directly on default risk.

## MEANS OF REDUCING THE COST OF CREDIT REQUIREMENTS

If credit protections are sought, procurement design should attempt to minimize their economic costs to bidders, while still providing adequate assurance to buyers. A way to minimize the cost of credit requirements on suppliers (and potentially on the resulting cost

[104] See reference to estimates reported by Starwood, Caithness and Black & Veatch in: Aspen Environmental Group and Sentech, 2007, p. 13.

[105] KEMA reports that short-list deposits for proxy projects in California renewables RFPs were $300,000 in three of ten RFPs reviewed and over $1.5 million in another. KEMA, 2006, p. 10.

[106] KEMA, 2006, p. 6.

of the winning supply) is for the utility to allow some flexibility to suppliers in how credit requirements are met.

Traditional means for providing credit include letters of credit from large, investment-grade financial institutions or financial guaranty from a credit-worthy entity, such as the parent company of the entity offering supply. These forms of security provide the procuring utility with a liquid source of funds that can be immediately drawn upon in the event of non-performance or default. However, the cost of obtaining and maintaining letters of credit may be high for developers. There may be situations where parent companies' desire to avoid providing additional finance beyond the equity typically included in such projects acts as a barrier to a supplier's participation in the procurement. Regulators should monitor the credit requirements placed on suppliers by utilities to assure themselves that the level and terms of the financial guarantees are appropriate to the risks involved in various stages of the process.

Recognizing the need for flexibility, other approaches have been used and are under development in an effort to provide lower-cost means of providing financial assurances to utilities. One approach is to provide the utility with a claim to project-specific assets, such as subordinate liens, in which the utility is granted rights as a creditor in the event of bankruptcy or default. Similarly, utilities may be granted rights to payments associated with plant equipment warranties or project insurance policies. The utility may receive step-in rights, in which it has the ability to take over project development in the event of developer default.[107] Suppliers may also provide an exclusivity guarantee to prevent it from selling to other parties. Because the value of many of these claims depend on market conditions at the time of non-performance, determining the financial value of the security provided by these claims may be more difficult than more traditional lines of credit or guaranties.[108] Other approaches are also being considered, such as securitizing specific agreement credit risks across multiple agreements, power supply clearinghouses or state operated risk pools.[109]

[107] Aspen Environmental Group and Sentech, 2007, p. 17.

[108] Comments by Southern California Edison in: Aspen Environmental Group and Sentech, Inc., 2007, p. 15.

[109] For example, see Ghosh, Partho S., "MMC Presentation to Electricity Committee Workshop on Lowering the Effective Cost of Capital for Generation Projects," June 27, 2006; references to MMC comments in: Aspen Environmental Group and Sentech, 2007, p. 17-18, 28, 33-34.

| Table B1 – Credit Requirements From Selected Procurements | | | |
|---|---|---|---|
| **RFP** | **Timing of Credit Requirements (after short-list; during construction; during operation)** | **Allowed Forms of Credit** | **Credit Requirement Amount** |
| Southern California Edison 2006 RFO (All Source) | • Development security from effective date (regulatory and contract approvals) to beginning of delivery<br>• Delivery security | Unspecified | • Development security of $109.6/kW (fast track) and $54.8/kW (standard track)<br>• Delivery security required for amounts above unsecured credit to cover mark-to-market exposure over a 24- or 48-month period. (Only investment grade bidders eligible for unsecured credit.)<br>• Seller grants secondary liens to SCE |
| Pacific Gas & Electric 2005 (New Generation Resources) | • Proposal fee<br>• Selection security (upon request for CPUC approval)<br>• Development security<br>• Operating security | Unspecified | • Proposal fee: $5/kW<br>• Selection security: $10/ kW<br>• Development security: $61/ kW<br>• Operation security: mark-to-market (either a 2- or 5-year window, depending on time to replace generation), and collateral threshold |
| Georgia Power Company and Savannah Electric Company 2009 RFP | Unspecified, but ability to meet credit standards or security requirements must be demonstrated in offer | Credit requirements may be met through:<br>1) Seller net worth threshold;<br>2) Guaranty from entity meeting net worth threshold;<br>3) Investment grade credit rating based on utility evaluation; or<br>4) Collateral sufficient to cover potential damages resulting from seller default (levels are not specified).<br>Unless a successful bidder (or its guarantor) is rated at least one notch above investment grade, then 50% of such bidder's security collateral must be in the form of cash or a letter of credit. | Credit requirements standards can be met through either demonstration of credit-worthiness (with specific Allowed Forms of Credit) or posting of collateral sufficient to cover necessary damages resulting from default |
| Progress Energy Florida (2003) | • Development security starting 30 days after contract signing<br>• Operating security starting 30 days prior to planned operation date for the duration of the contract | Letter of credit, cash, or U.S. bonds held in escrow | • Development security starting at $20/ kW and rising to $50/kW (at 12 months before commercial operation)<br>• Initial operation security of $10/kW, $20/kW after 5 years, and $30/kW after 10 years |

**Table B1 – Credit Requirements From Selected Procurements**

| RFP | Timing of Credit Requirements (after short-list; during construction; during operation) | Allowed Forms of Credit | Credit Requirement Amount |
|---|---|---|---|
| Entergy 2006 RFP for Long-Term Supply-Side Resources | • Letter of intent security<br>• Performance collateral upon execution of agreement | • Traditional forms of collateral and non-traditional forms on a case-by-case basis (e.g., lien on assets and step-in rights) | • Letter of intent security of $2 million letter of credit<br>• Performance collateral: $200 per kW for solid fuel; $100 per kW for CCGT<br>• Entergy determines amount of uncollateralized exposure based on the bidder's credit rating (up to $100 million for AAA to A-) |
| Northwestern Energy (Issued July 2, 2004) | Unspecified | • Demonstration of investment grade credit rating<br>• Acceptable performance assurance, including letter of credit, guaranty from parent company, or cash | Unspecified |
| PacifiCorp's 2012 RFP | Security starting on the date of PUC contract approval or execution by parties (starting at 10% of full credit and rising to 100% in 2 years, with full credit due when financing secured) | • On-going: letters of credit, guaranties, cash or other collateral<br>• Asset-back agreements "must" backup agreement with the resource through certain options, including step-in rights, second lien, leverage limitations, and other financial covenants<br>• Initial (10%) security must be posted with letter of credit or cash unless 100% of security is posted at effective date | • Credit requirements reflect PacifiCorp's market exposure given type of agreement, agreement term, and other factors<br>• Credit matrix identifies security requirement based on type of resource, size of resource, and the year the resource is expected to be operational<br>• PacifiCorp permits some uncollateralized supplier exposure depending on seller's credit rating and the type of resource |
| PacifiCorp's 2009 RFP | Security starting on the date of PUC contract approval or execution by parties (starting at 10% of full credit and rising to 100% in 2 years) | Acceptable "credit assurances" are unspecified (letter of credit is acceptable) | • Credit matrix based on type of resource, size of resource, and the year the resource is expected to be operational<br>• PacifiCorp permits some uncollateralized supplier exposure depending on seller's credit rating and the type of resource |
| Puget Sound Energy 2008 All Source RFP | Unspecified | Unspecified | May be required to post collateral absent demonstration of credit-worthy status (BB+ or better) or guaranty from credit-worthy parent company |

**Sources:**

[1] Southern California Edison, RFO for New Generation Resources, Transmittal Letter, August 14, 2006, pp. 16-17.

[2] [Pacific Gas & Electric] KEMA, Inc., "The Cost of Credit: A Review of Credit Requirements in Western Energy Procurement," prepared for the California Energy Commission, CEC-300-2006-014, 2006.

[3] Georgia Power Company and Savannah Electric Company 2009 RFP (Draft), July 5, 2005, pp. 10-11.

[4] [Progress Energy Florida] Merrimack Energy Group, Inc., "Report of the Independent Evaluator Regarding PacifiCorp's 2012 Request for Proposals for Base Load Resources," Utah PSC Docket 0503547, August 30, 2006, pp. 2-3.

[5] [Enetergy] Merrimack Energy Group, 2006, pp. 9-10.

[6] Northwestern Energy RFP Issues July 2, 2004, p. 12.

[7] PacifiCorp 2009 RFP for Flexible Resources (Draft), Responses due December 1, 2005, pp. 15-16.

[8] PacifiCorp 2012 Credit Security Requirements Methodology Overview, pp. 1-5.

[9] Puget Sound Energy 2008 All Source RFP, January 2008, pp. 10-11.

## APPENDIX C – DEBT EQUIVALENCY

The report previously described the two most common methods for addressing the financial impact of the debt-like commitments taken on by utilities when entering into power purchase agreements. These two methods address these issues either

(a) through the cost-of-capital and capital structure phases of general rates cases; and/or

(b) through use of adders to third-party offers that introduce an economic penalty on third-part offers relative to utility self-build proposals.

Because regulators are more familiar with addressing a variety of risk issues faced by utilities in cost-of-capital and capital structure issues in general rate case proceedings, in this appendix we focus on the latter approach; that is, methods used to develop adders to account for debt-equivalency affects in the context of competitive procurement proceedings.

The methods used to estimate inferred debt "adders" generally draw upon the explicit balance sheet adjustments made by credit ratings agencies to take into account a utility's relative default risk as a result of its contractual financial obligations, including PPAs.[110] Under these methods, the level of inferred debt depends on the size of fixed payments assumed in these contracts and a risk factor that reflects the likelihood of full cost recovery of these PPA costs given the specific regulatory and legislative conditions affecting recovery. The risk factors used by credit agencies may depend on the relevant state commission's "reputation" regarding cost recovery and specific aspects of state's utility regulation, such as whether there is a mechanism for automatic rate adjustment, whether the Commission has approved the RFPs or the selection of offers, and whether legislative requirements are supportive of cost recovery.[111]

When considering whether to allow utilities to use some form of risk-adjustment adder to compare contracts against self-build options in the context of competitive procurements, commissions should be mindful of what they already know in general – that is, that the inferred debt adjustment made by credit agencies is not the only impact on credit ratings from a utility signing a PPA. In fact, Standard & Poor's has explicitly indicated that it accounts for many factors when assessing utility credit risk, including other factors that may affect the choice between alternative types of supply agreements. For example, credit agencies would recognize the reduced utility exposure to commission prudence determination that would arise from entering into a PPA rather than adding additional

[110] For example, see Standard & Poor's, 2007.

[111] For example, see Standard & Poor's, 2007.

capital to the utility's rate base.[112] Because inferred debt calculations do not account for these factors, regulators should be careful not to infer that risk factors account for the net impact of PPAs on either the utility's cost of capital (via its credit status), let alone the final financial risks to consumers. Unfortunately, there is relatively little empirical analysis to shed light on the net impact of PPAs on utility's cost of capital.[113]

Because of these factors, while most states that include debt equivalency "adders" utilize the same basic methodologies, the specific risk factors that commissions have used range from 15% to 50% across procurements. For example, Washington allows a risk factor of 40% for take-or-pay contracts, and 15% for other PPAs, and, in Louisiana, Entergy procurements use of a risk factor of 50%.

[112] "That said, PPAs also benefit utilities that enter into contracts with supplier because PPAs will typically shift various risks to the suppliers, such as construction risk and most of the operating risk." Standard & Poor's 2007).

[113] What research has been done suggests that PPAs have little effect on a utility's cost of capital, while utility self-builds raise it. However, various limitations to this study caution against any broad conclusions from its results, the results do suggest that the importance of understanding the risk tradeoffs posed by alternative agreement forms to selecting the most desirable supply alternatives. Kahn, Edward et al., "Impact of power purchased from non-utilities on the utility cost of capital," Utilities Policy 5(1): 3-11, 1995.

## APPENDIX D – EVALUATION OF PRICE AND NON-PRICE FACTORS

| Source | State | RFP | Monetized | Non-monetized |
|---|---|---|---|---|
| **Illustrative Examples – Ways that Different Utilities Have Addressed Various Price and Non-Price Factors, and Whether These Factors Have been Monetized** | | | | |
| [1] | UT | PacifiCorp 2009 | Price, based on ratio of bid price to projected price (60%)[114]: (for a ratio of [x], the bid gets [y] points:)<br>• Ratio < or =l to 80%: 100%<br>• Ratio > 80%, but < 120%: 100% times ratio<br>• Ratio > or = 120%: 0% | Non-price factors will be weighted (40%):<br>• Flexibility of resource dispatch: day-ahead and adjustment: 20%; or only day-ahead: 10%<br>• Exceptions to any pro forma agreements: 10%<br>• Environmental attributes relative to the resource, if applicable: 10% |
| [2] | OR | PacifiCorp 2012 | Price, based on ratio of bid price to projected price (70%)[115]:<br>• Ratio < or = to 80% of adjusted price curves: 100%<br>• Ratio > 80%, but < 120%: 100% times ratio<br>• Ratio > or = 120%: 0% | Nonprice factors will be weighted (30%):<br>• Development, construction, operational experience: 10%[116]<br>• Compliance with pro forma agreements submitted with proposal: 10% [117]<br>• Site control and permitting: 10% |
| [3] | OK | Oklahoma Gas & Electric Co. 2008-2010 RFP | Price factor (60%), reflecting:<br>• Capacity charge<br>• Energy charge<br>• Start-up charge<br>• Transmission system impact | • Bidder's proposed changes to Model PPA: 10%<br>• SPP RTO market risk cost allocation: 15% [118]<br>• Quality of output: 15%<br>- Dispatchability/scheduling<br>- Reliability/availability<br>- Operating profile/characteristics |

[114] Total score reflects score on price ratio multiplied by weight, for example if ratio = 90%, score = (90*0.6) = 54.

[115] Total score reflects score on price ratio multiplied by weight, for example if ratio = 90%, score = (90*0.7) = 63.

[116] One percent point for each project the bidder has previously developed, constructed and/or operated, with partial points awarded for partial experience.

[117] Modifications to pro forma agreements could result in a reduction in the bidders score (out of 10%) if those modifications resulted in a material shifts in risk or cost from the bidder to the utility. This process and percentage application per section within the pro formas was to be validated by the IE.

[118] SPP/RTO Market criteria was intended to relates to the bidder's proposed methodology for the sharing or allocation of market benefits and risks between bidder and OG&E that may arise from changes to SPP RTO market rules.

| Illustrative Examples – Ways that Different Utilities Have Addressed Various Price and Non-Price Factors, and Whether These Factors Have been Monetized | | | | |
|---|---|---|---|---|
| **Source** | **State** | **RFP** | **Monetized** | **Non-monetized** |
| [4] | AZ | Arizona Public Service Commission 2007 RFP for Renewables | Quantitative[119]:<br>Respondent Bid Price plus Additional Costs is compared against Market Cost of Comparable Conventional Generation[120] | • Financial risk<br>• Regulatory risk<br>• Counterparty credit risk<br>• Transmission risk<br>• Operations risk<br>• Project development risk |
| [5] | MT | NWE 2004 RFP | Proposal price and value, including:<br>• Costs/benefits of transmission<br>• Value of dispatchability<br>• Firmness of products<br>• Ability to remarket energy<br>• Value of points of delivery<br>• Ancillary services value<br>• Costs of resource integration | • Development and performance risk (2nd most important factor)<br>• Environmental factors (3rd most important factor) |
| [6] | FL | Progress Energy 2007 RFP | • All costs, as reflected in 30 year optimization analyses | Minimum bidder eligibility requirements:<br>• Environmental<br>• Engineering and design<br>• Fuel supply and transportation plan<br>• Project financial viability<br>• Project management plan<br>Technical criteria:[121]<br>• Development feasibility<br>• Project value<br>• Operational quality |

[119] Respondents were advised that price would be a major factor in APS' evaluation, but APS will consider other quantitative and qualitative risk factors.

[120] "Respondent Bid Price" referred to the amount APS would pay to the respondent. "Additional Costs" were costs that are needed to incorporate the renewable resources into APS' system, including additional interconnection costs, system integration costs, and costs associated with imputed debt (for PPA proposals). "Market costs of conventional generation" were to reflect the utility's energy and capacity cost of producing or procuring incremental electricity from a conventional resource.

[121] "Development feasibility" were to reflect the bidder's ability to meet development schedules, such as permitting certainty, financial viability, commercial operation date certainty, and bidder experience. "Project value" were to reflect the project's cost and flexibility, including acceptance of key terms and conditions, fuel supply and transportation reliability, reliability impact, and flexibility provisions. "Operational quality" was to measure the proposed unit's flexibility to respond to changes in system demand, including minimum load, start time, ramp rate, max starts/year, minimum run-time/down-time constraint, and annual operating hour limit.

**Illustrative Examples – Ways that Different Utilities Have Addressed Various Price and Non-Price Factors, and Whether These Factors Have been Monetized**

| Source | State | RFP | Monetized | Non-monetized |
|---|---|---|---|---|
| [7] | WA | Puget Sound Energy (PSE) | • Resource cost<br>• Transmission<br>• Portfolio cost impact[122]<br>• Capital structure impacts<br>• Guarantees and security[123] | • Timing<br>• Resource match to monthly need<br>• Operational flexibility<br>• Performance within utility's own resource mix/portfolio<br>• Status and schedule<br>• Price volatility<br>• Resource flexibility and stability<br>• Resource technology<br>• Long-term flexibility<br>• Project risk<br>• Impact on PSE's overall risk[124]<br>• Environmental & permitting risk<br>• Ability to deliver as proposed<br>• Status of transmission right<br>• Managerial control<br>• Security & control<br>• Federal regulatory approvals<br>• Environmental impacts<br>• Resource location<br>• Community impacts<br>• Future exposure to taxes and/or environmental regulation |
| [8] | LA | Entergy Fall 2006 RFP | Individual and portfolio costs, as estimated by a production cost model | Non-quantifiable aspects of:<br>• Transmission<br>• Fuel cost and availability<br>Portfolio design criteria, including:<br>• Product category supply cost ranking<br>• Maximum total resource objective<br>• Regional dispersion<br>• Product category needs<br>• Mix of product terms |

[122] Portfolio cost impacts taken into consideration for proposals that make the preliminary shortlist.

[123] PSE took into consideration credit information provided by the bidder to determine whether PSE would requires any additional guarantees or credit support, and include the estimated costs of providing such guarantees or credit support to the bidders proposed offer terms.

[124] The impact on PSE's overall risk position was considered for proposals making the preliminary shortlist.

| **Illustrative Examples – Ways that Different Utilities Have Addressed Various Price and Non-Price Factors, and Whether These Factors Have been Monetized** | | | | |
|---|---|---|---|---|
| **Source** | **State** | **RFP** | **Monetized** | **Non-monetized** |
| [9] | GA | Georgia Power Company and Savannah Electric 2009 RFP | Fixed costs:<br>• Capacity cost payment<br>• Fixed O&M payment<br>• Cost due to inferred debt from PPA[125]<br>• Startup costs<br>• Fuel pipeline costs, including the estimated costs for adequate firm natural gas transportation and natural gas storage<br>Variable generation costs:<br>• Fuel cost<br>• Variable O&M<br>• Proposal dispatch characteristics<br>Transmission costs:<br>• Integration costs<br>• The increase (or decrease) in transmission system energy losses | Development schedule:<br>• Reasonableness<br>• Contingencies<br>• Current developmental status<br>Resource schedule and dispatch flexibility:<br>• Lead time for dispatch schedules[126]<br>• Ability to change schedules hourly/daily[121]<br>• Quick start capability or curtailment<br>• Minimum schedule and downtime<br>• Minimum energy take[121]<br>• Response to emergencies<br>• Dispatchability[121]<br>• AGC capability<br>Fuel:<br>• Type of fuel<br>• Risk of fuel supply interruption<br>• Price risk<br>Environmental:<br>• NOx. VOC and $SO^2$ compliance strategy<br>• Toxic release inventory<br>• Future permitting restrictions<br>• Water requirements<br>Proposed PPA changes<br>Transmission:<br>• Impact on transmission interface capability[121]<br>• Transmission delivery risk[121]<br>• Voltage control[121]<br>• Other grid impacts[121] |

[125] The equity cost of lease reflects an estimate of the "debt equivalency" impacts as measured by either the PPA's balance sheet impact on the balance sheet (in the case of capital lease) or the capital structure adjustment necessary to cover the imputed debt burden (in the case of an operating lease).

[126] Where possible, this might be converted into an explicit price factor.

| Illustrative Examples – Ways that Different Utilities Have Addressed Various Price and Non-Price Factors, and Whether These Factors Have been Monetized | | | | |
|---|---|---|---|---|
| **Source** | **State** | **RFP** | **Monetized** | **Non-monetized** |
| [10] | CA | Southern California Edison 2006 RFO | • Market assessment: the market value of the benefits contained in each offer versus its costs[127]<br>• Transmission impact: cost of network upgrades<br>• Debt equivalence as additional cost<br>• *Environmental: greenhouse gas emissions adder ($8 per ton of $CO^2$)*<br>• Credit: ability to post collateral if necessary | • Ability to fill capacity requirements<br>• Portfolio fit: impact the offer has on (i) the demand and supply effect on CAISO zone and (ii) the ability of SCE's portfolio to meet SCE's RAR[128]<br>• Project viability: ensure project can be constructed consistent with terms of RFO<br>• Physical concentration risk[129]<br>• Financial concentration risk |

**Sources:**

[1] PacifiCorp 2009 RFP Flexible Resources, September 2005, pp. 26-38.

[2] PacifiCorp 2012 RFP Base Load Resources, April 5, 2007, pp. 30-35.

[3] Oklahoma Gas & Electric Company, RFP for Capacity and Energy Resources Years 2008-2010, Issued March 29, 2007, pp. 13-17.

[4] Arizona Public Service Commission 2007 RFP for Renewable Resources, March 5, 2007, pp. 8-11.

[5] Puget Sound Energy, RFP for All Generation Resources, January 2008, Exhibit B; and Puget Sound Energy, 2006 RFP for Long-Term Supply Side Resources, p. F-4.

[6] Progress Energy Petition for Determination of Need of Hines 4 Combined Cycle Unit, August 4, 2004, pp. 50-66.

[7] Northwestern Energy RFP issued July 2, 2004, pp. 6-8.

[8] Entergy Fall 2006 RFP for Limited-Term Supply-Side Resources, October 24, 2006, Appendix E.

[9] Georgia Power Company and Savannah Electric and Power Company 2009 RFP, July 5, 2005, pp. 18-19.

[10] Southern California Edison 2006 New Gen RFO, Transmittal Letter, August 14, 2006, pp. 15-16.

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[127] Potentially including capacity payments, start up charges, variable operating and maintenance costs, and fuel costs resulting from offer heat rates.

[128] Factors influencing the portfolio fit could also include but are not restricted to: the range of offers that are available for selection; variable costs; volume in MW offered; unit flexibility (e.g., ramp rates, start times, ancillary service capabilities); the proposed initial delivery date; and the agreement's duration.

[129] Portfolio Concentration Risk referred to both (1) "portfolio concentration risk" reflecting potential electric system reliability and continuity of service risks from over reliance on purchases from a particular technology, and (2) "financial concentration risk" from significant monetary exposure to a single counterparty. CPUC Decision 02-10-062 requires SCE to devise procurement strategies that procuring generation from a variety of fuel sources and a variety of counterparties.

# APPENDIX E – STATES WITH PROCUREMENTS FOR RETAIL SUPPLY OF FULL REQUIREMENTS SERVICE

## Overall Frameworks Used in Selected States Procuring FRS Supply[130]

| | CT | DE | DC | ME | MD | MA | NJ |
|---|---|---|---|---|---|---|---|
| Does state have regulations about FRS procurement? | Yes | Yes | Yes | Yes | Yes | Yes | Yes |
| Bid Payment Form | Pay-as-bid | Pay-as-bid | Pay-as-bid | Pay-as-bid | Pay-as-bid | Pay-as-bid | Uniform price |
| Price-only offers? | Yes | Yes | Yes | Yes | Yes | Yes | Yes |
| Are generation-owning affiliates able to bid? | – | Yes | Yes | Yes | Yes | Yes | Yes (With BPU approval) |
| Annual "lessons learned" process? | Yes | Yes | Yes | – | Yes | No | Yes |
| Does bidder eligibility include credit criteria? | Yes | Yes | Yes | Yes | Yes | Yes | Yes |
| Do bidders need to post collateral? | Yes | Yes | Yes | Yes | Yes | Yes | Yes |
| Do bidders provide indicative bids? | No (based on recent RFP) | No (based on recent RFP) | No | Yes | No (based on recent RFP) | Yes | Yes |
| Who oversees process on a daily basis? | Utility, with oversight by IM | PUC, with help of PUC-retained IM | IM | PUC; No IM | IM (retained by utilities) | Utility No IM. | IM retained by utilities; BPU has a consultant |
| Time between submitting final bids and selection of winner | 5 hours (e.g., UI's recent SOS procure-ment) | 1 day | 1 day | 1+ months | 4 hours beginning in 2008 (previously 1 day) | 5 hours (e.g., recent RFP) | ~50 minutes between bidding rounds |
| Timing of RFPs / Auction | Separate RFPs for each utility (one solicits semi-annually; the other each year) | Largest utility staggers two tranches (1-2 months apart) | Only one utility | All utilities procure power at same time but use separate RFPs. | All utilities procure power at same time but use separate RFPs. | Utilities stagger annual procure-ments (2 in Jan, 1 in Feb, 1 in Mar) | All utilities solicit through a single auction |

[130] There are other states (e.g., Illinois) that have carried out FRS procurements.

## Additional information About Products Recently Procured in Selected States Procuring FRS Supply[131]

| State | FRS Products Procured: |
|---|---|
| CT | Four product classes for standard offer service with separate pricing for:<br>(1) residential; (2) small commercial and industrial; (3) large commercial and industrial, and (4) street lighting classes.<br>Both major utilities have used a laddering approach, with a portion of the total power requirements contracted over a three-year cycle, to create a blended portfolio. |
| DE | Four product classes, in two overall groupings:<br>Small – residential/small commercial and industrial: procurement has 3 contract lengths, offered simultaneously (13-month term, 25-month term, and 37-month term in 2005; in 2006 only a 36-month term);<br>Larger – (a) medium general service – secondary; (b) large general service – secondary; and (c) general service – primary customers: 13-month term only in 2005 (in 2006 only a 12-month term) |
| DC | Three product classes, procured via the following two contract terms:<br>(1) residential and (2) small commercial = 30% using 16-month contracts; 30% using 28-month contracts; 40% using 40-months or more;<br>(3) large commercial 60% using 16-month contracts; 40% using 28-month contracts; |
| ME | Three product classes:<br>(1) residential/small commercial: procurement is 3-year contract offered once per year for 1/3 of load;<br>(2) medium commercial/industrial and (3) large commercial industrial: procurement is 6-month contract offered twice per year for 100% of load |
| MD | Beginning in 2008 the products are:<br>(1) residential and small commercial: 2-year contracts for 25% of load, RFP issued twice a year; and (2) mid-to-large commercial and mid-sized industrial: 3-month contracts for 100% of load, RFP is issued 4 times a year |
| MA | Two product classes:<br>(1) residential (and small commercial): procurement is 12-month contract offered twice per year for 50% of load; and (2) medium/large commercial & industrial: procurement is 3 month contract offered 4 times per year for 100% of load. |
| NJ | Two types of contract approaches:<br>(1) fixed price contract to serve small to mid-size customers; must serve a fixed % share of load; 3-year contract; 1/3 of load procured each year<br>(2) hourly-priced contract for large customers; must serve a fixed % share of load; receive a capacity payment and an energy payment determined by the PJM real-time hourly market; 1-year contract; 100% of load procured |

[131] There are other states (e.g., Illinois) that have carried out FRS procurements.

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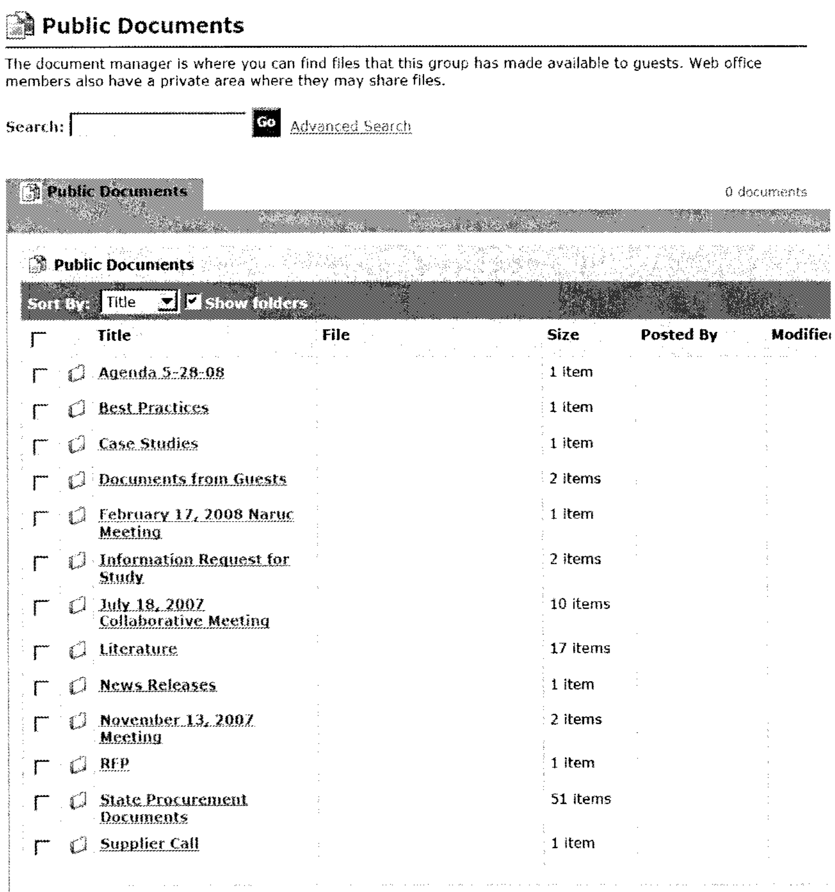
As part of our analysis of competitive procurements of retail electricity supply, we compiled and reviewed a substantial amount of literature. These documents include regulations, opinions, and reports from government agencies; white papers from industry experts and interest groups; actual procurement documents; and other sources in the public domain.

These documents are posted on the website of the NARUC-FERC Collaborative Process on Competitive Procurements. Members of the public can gain access to these documents by logging on to the website as a guest. The address is:

http://procurement.webexworkspace.com/login.asp?loc=&link=

The website includes a wide variety of documents, as shown in the excerpt from the website, below.



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| Documents from Guests | | 2 items | | |
| February 17, 2008 Naruc Meeting | | 1 item | | |
| Information Request for Study | | 2 items | | |
| July 18, 2007 Collaborative Meeting | | 10 items | | |
| Literature | | 17 items | | |
| News Releases | | 1 item | | |
| November 13, 2007 Meeting | | 2 items | | |
| RFP | | 1 item | | |
| State Procurement Documents | | 51 items | | |
| Supplier Call | | 1 item | | |

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Electric Power Supply Association
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# STATE COMPETITIVE PROCUREMENT: MODEL SUCCESS STORIES AND LESSONS LEARNED

## I. Introduction

In November 2007, at the request of the Electric Power Supply Association (EPSA),[1] the Dickstein Shapiro law firm prepared a survey entitled "State Competitive Procurement Practices: A Partial Survey of Best Practices" ("Survey").[2] The Survey included examples of the rules governing various state competitive procurement programs, and also proposed Model Rules and Best Practices that might be helpful for either the design or improvement of state competitive procurement procedures. The Survey was offered by EPSA to assist the ongoing efforts of the joint task force on competitive procurement that has been convened by the National Association of Regulatory Utility Commissioners (NARUC) and the Federal Energy Regulatory Commission (FERC).

This follow-up paper, also prepared with Dickstein Shapiro's assistance, highlights case studies from various actual competitive procurement regulations, orders and Requests for Proposals ("RFPs"), grouped into "model success stories" and "lessons learned stories." We have attempted neither to disparage nor to extol any particular state's experience with competitive bidding, but rather, applying the Model Rules and Best Practices from our earlier survey, to determine what has been particularly successful (or unsuccessful) in these processes, with the objective of assisting the joint task force's continuing deliberations and those of individual states. While competitive procurement is most important in non-restructured states, elements of a successful program can be seen across regulatory structures. EPSA hopes that this survey will prove valuable.

## II. Competitive Procurement: Model Success Stories

### A. Arizona

In 2001, the Arizona Public Service Company ("APS"), Arizona's largest investor-owned utility, filed an application before the Arizona Corporation

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1 EPSA is the national trade association representing competitive power suppliers, including generators and marketers. These suppliers, who account for 40 percent of the installed generating capacity in the United States, provide reliable and competitively priced electricity from environmentally responsible facilities serving U.S. power markets. EPSA seeks to bring the benefits of competition to all power customers. The comments contained in this filing represent the position of EPSA as an organization, but not necessarily the views of any particular member with respect to any issue. Go to www.epsa.org for more information.

2 http://epsa.org/forms/documents/DocumentFormPublic/view?id=B5E200000031

Commission ("ACC" or "Commission") in Docket No. E-01345A-01-0822, seeking to suspend the state's Electric Competition Rules, and to instead secure the state's long-term power needs through a power purchase agreement between APS and its unregulated affiliate, Pinnacle West Energy Corporation ("PWEC"). Specifically, APS sought a variance from the state's competitive bidding requirements, stating that "adherence to the competitive bidding requirements of the Electric Competition Rules will not produce the intended result of reliable electric service for Standard Offer customers at reasonable rates."

APS's application arose years after Arizona had publicly committed to meeting all of the state's wholesale electric power needs through all-source competitive bidding, and after numerous competitive power companies had invested billions of dollars in the state to develop facilities to serve those needs. APS, pointing to the recent collapse of California's wholesale competitive market regime, alleged that only a long-term power purchase agreement between APS and its non-utility power affiliate, PWEC, could reliably serve Arizona's load. A coalition of competitive power firms with plants either in operation or under construction in Arizona intervened in the APS proceeding. After an extended administrative proceeding, the Commission rejected APS's application, and ordered all-source competitive bidding.[3] In rejecting APS's request, the Commission established specific bidding rules to ensure a competitive, transparent process designed to identify least-cost solutions to APS's power needs. The Commission stated that APS was obligated to "acquire, at a minimum, any required power that cannot be produced from [APS's] existing assets, through the competitive procurement process."[4] In other words, in determining the amount of power to be solicited in the competitive solicitation, APS was required to test the market beyond what it could not acquire from its own utility assets or through existing contracts to consider whether alternative generation was reliable and less costly than what could be provided by APS or PWEC might be available in the wholesale market.

In addition, the Commission determined that the generating assets of PWEC could not be counted as APS assets for purposes of determining the amount of power to be acquired through the competitive procurement process, thus establishing that PWEC would be forced to compete on an equal footing with non-affiliated generation to service APS load. The Commission also stressed the importance of establishing standards of conduct, and specific restrictions governing the interactions between APS and its affiliates with respect to the competitive procurement process. The Commission precluded APS from giving preferential treatment to PWEC by virtue of its affiliation with APS (for example PWEC's access to gas capacity or transportation rights by virtue of APS's contract with its affiliate El Paso Natural Gas Company). Finally, the

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3 *In the Matter of the Generic Proceedings Concerning Electric Restructuring Issues, Opinion and Order*, Arizona Corporation Commission, Docket Nos. E-00000A-02-0051, *et al.* (Sept. 10, 2002) ("Track A Proceeding") ("ACC September 10 Order") *available at:* http://www.cc.state.az.us/divisions/utilities/electric/Gen020051/020051fi.pdf; 2003 Ariz. PUC LEXIS 2 ("March 14, 2003) ("Track B Proceeding") *available at:* http://www.cc.state.az.us/divisions/utilities/electric/Track-B-03-19-03.pdf.

4 ACC September 10 Order at 23.

Commission ordered the retention of an independent monitor and additional Commission staff oversight of the solicitation process to ensure that utilities such as APS ran the RFP process to serve the best interests of its customers.

This case study demonstrates the benefits of a state commission vigilantly enforcing its own competitive procurement rules, to the benefit of its electricity customers. ACC Commissioner Hatch-Miller recently stated that the state's competitive procurement processes have saved APS's ratepayers $70 million.[5] Most recently, the ACC adopted the "Recommended Best Practices for Procurement," a report drafted by ACC staff that incorporated findings from numerous workshops and extensive review of resource planning issues. The Recommended Best Practices for Procurement specifically identifies acceptable procurement methods, states a preference for RFPs, describes the limited exceptions when a utility need not utilize the RFP process, and supports the role of an independent monitor in the procurement process.[6]

### B. California

While the state's three major investor-owned utilities or their affiliates have partially reentered the California generation markets in recent years, there remains a thriving competitive power sector in the state, and the "utility-build" option remains the exception rather than the rule, the backstop rather than the preferred means of serving load. In addition, California's aggressive approach both to fostering the development of renewable resources and to reducing greenhouse gases has been addressed predominantly through market-based mechanisms.

For several years, the California Public Utilities Commission ("CPUC") has published and revised highly detailed rules governing the California utilities' long-term procurement plans ("LTPPs"). In the most recent version of the LTPP, issued at the end of last year,[7] the CPUC addressed a wide array of issues with respect to the utilities' procurement processes, including:

> 1. *Independent Evaluator.* An independent evaluator ("IE") must be chosen to oversee all competitive solicitation processes that involve IOU affiliates or utility-owned turnkey bids. The IE must be selected by the IOU using a transparent process. Under the current LTPP, the IOU has authority to contract directly with the IE, based on CPUC-established criteria. However, the CPUC has specifically reserved the right to remove that contracting authority from the IOUs, and for the CPUC itself to hire the IE in the future.[8]

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5 Transcript of July 18, 2007 NARUC/FERC Competitive Procurement Dialogue Meeting, at 5.

6 *In the Matter of Competitive Procurement Issues in the Generic Investigation into Electric Resource Planning,* Arizona Corporation Commission, Docket No. E-00000E-05-0431, (Dec. 4, 2007).

7 2007 Cal PUC LEXIS 606 (Dec.20, 2007), *available at:* http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/76979.pdf.

8 *Id.* at 136-137.

2. *Transparency.* When IOUs submit applications for Commission approval of winning bid projects, they must submit detailed descriptions of the bid selection and approval process to ensure transparency.[9] California has one of the most comprehensive and vigorous oversight regimes governing affiliate transactions in the nation.

3. *Debt Equivalency.* Debt equivalency ("DE") – the imputation by credit agencies of debt to LSEs that enter into long-term contracts with competitive power producers – has been the subject of debate within the industry for over a decade. In some instances, the issue of debt equivalency has been raised by LSEs as a reason to improperly inflate the price of competitive bids, and to instead favor self-build options over competitive procurement. In prior LTPP orders, the CPUC had permitted California's LSEs to include a debt equivalency factor when evaluating proposed PPAs in competitive solicitations in order to "quantify risks presented by IPP projects,"[10] while utility-owned projects would include no such factor. In its most recent LTPP order, the CPUC eliminated the DE factor, in order to encourage fair competition between PPAs and utility-owned projects.

4. *Utility-Owned Generation Bids v. Independent Power Producer Bids.* The CPUC will allow head-to-head competition between non-utility generators and utility-owned generation ("UOG") only if the IOU develops a detailed code of conduct to prevent information sharing between utility employees who develop the bids, and staff who create the bid criteria and evaluate winning bids.

5. *Greenhouse Gas ("GHG") Issues.* The CPUC directed that procurement of zero-GHG or low-GHG resources should be given preference in competitive solicitations for new generation. The CPUC stated that it would provide guidance in its future LTPPs as to how IOUs should consider the costs and risks associated with GHG reduction.[11] This recent addition to the LTTP underscores the emergence of "speciality" RFPs, i.e. competitive solicitations that seek generation resources with particular environmental or other features, rather than "pure commodity" RFPs, which solicit bids for a particular amount of generation regardless of the fuel source of that generation.

The following example illustrates how the CPUC's LTTP rules were applied in a specific competitive procurement. The CPUC's 2004 LTTP directed PG&E to procure 2,200 MW of new generation in northern California by 2010. Pursuant to the CPUC's directive, PG&E conducted an all-source solicitation to procure the needed resources. PG&E received over 50 bids totaling in excess of 12,000 MW through the competitive

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9 *Id.* at 149-150.

10 *Id.* at 165.

11 *Id.* at 244.

solicitation process. In 2006, PG&E submitted a number of long-term PPAs to procure 2,250 MW of new generation resources that had been identified through the competitive solicitation process conducted pursuant to the 2004 LTTP. The CPUC cited an IE report on PG&E's conduct with respect to the solicitation process which determined that PG&E had "conducted an open, competitive, and fair solicitation and contract selection process."

In the 2006 proceeding, certain parties objected to PG&E's proposed PPAs because PG&E had, in addition to and outside the scope of the 2,250 MW of new generation at issue in the RFP proceeding, received approval to construct and operate the 530 MW Contra Costa project.[12] Although the CPUC approved the 530 MW Contra Costa PPA in a separate proceeding, the CPUC determined that the Contra Costa project would not count against the 2250 MW of generation authorized by the CPUC under the 2004 LTTP. Certain parties objected that the combination of both the Contra Costa project and the 2250 MW RFP exceeded the 2200 MW of new generation authorized under the 2004 LTTP. The CPUC responded by explaining that "[w]e do not count the Contra Costa 8 project against the 2,200 MW authorized in D.04-12-048, as so doing would undermine our commitment to a comprehensive and cohesive process for evaluating the utilities' long-term procurement plans and to a competitive bidding and bid evaluation process for procuring resources pursuant to those plans."[13]

### C. Maryland

In April 2003, the Maryland Public Service Commission ("MPSC") approved a settlement agreement among twenty parties, including Potomac Edison Company ("Potomac"), an affiliate of Allegheny Energy Supply Company, LLC, ("AE Supply") that established a competitive solicitation process to procure standard offer service in Maryland upon expiration of the utility rate freeze. Later that year, the MPSC approved another settlement that established specific rules and requirements for implementing a statewide RFP process. The MPSC determined that the RFP process established through the settlements "reflects the outcome of extensive and exhaustive negotiations between informed parties of diverse and traditionally adverse interests."[14]

Each of Maryland's four electric utilities, including Potomac, issued RFPs for standard offer service, as contemplated by the settlements. Consistent with the settlements, potential bidders were first required to submit documentation supporting their qualification as standard offer service suppliers. All potential suppliers, including affiliates, were required to submit a confidentiality agreement and documentation confirming that the supplier was: a member of PJM, a qualified market buyer, a market seller in good standing, and federally authorized to make wholesale sales of energy, capacity, and ancillary services at market-based rates. Potential bidders were also

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12 2006 Cal PUC LEXIS 464 (Nov. 30, 2006).

13 *Id.* at *10.

14 MdPSC Order No. 78710 at 3, *available at:* http://webapp.psc.state.md.us/Intranet/Casenum/NewIndex3_VOpenFile.cfm?ServerFilePath=C%3A%5CCasenum%5C8900%2D8999%5C8908%5C269%2Epdf.

required to submit relevant financial information, and to post collateral to demonstrate the financial commitment of the bidder. By requiring that potential suppliers qualify as bidders in advance of submitting a bid, the RFP process was designed to ensure that "all submitted bids met a minimum standard for certain non-price factors."[15]

Suppliers submitted bids on standardized spreadsheets, which included volume and prices for both summer and non-summer energy and demand. Suppliers were also authorized to submit bids of varying contract lengths. Potomac selected winning bids based on a single calculated price for each bid, which was determined based on a weighted average of different period prices for energy and demand, discounted prices based on contract lengths, and other parameters established by the utility. This calculation is called the Discounted Average Term Price, and is unique to the Maryland RFP process. Winning bids were binding, and winning bidders received the actual price submitted in their offers.

Potomac's RFP was monitored by an independent consultant who was specifically hired at the direction of MPSC, and who met certain qualifications established by the MPSC. The consultant reported directly to the MPSC, and his responsibilities included monitoring the solicitation process to ensure that the RFP process met the criteria established under the MPSC approved settlements.

AE Supply, an affiliate of Potomac, submitted a bid into Potomac's RFP process, and won bids to provide a portion of Potomac's requirements for the provision of standard offer service to its retail customers, along with a number of other selected suppliers.

AE Supply then applied for FERC authorization to sell at market-based rates to its affiliate Potomac, pursuant to the terms of the transactions resulting from the Potomac RFP process. In granting AE Supply's application, FERC explained that Potomac's RFP Process met the *Edgar* criteria, meaning that: "(1) a competitive solicitation process was designed and implemented without undue preference for an affiliate; (2) the analysis of bids did not favor affiliates, particularly with respect to non-price factors; and (3) the affiliate was selected based on some reasonable combination of price and non-price factors."[16] The Commission found that the transparent, non-preferential competitive solicitation process satisfied Commission concerns about affiliate abuse, and so the Commission granted AE Supply's application to sell at market-based rates to Potomac.

This particular case study underscores the circumstances under which utility-affiliated generation may bid in model competitive procurement regimes. By establishing a transparent bidding process, overseen by an independent monitor, the state ensures (a) that non-affiliated bidders can participate in such procurements

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15 *Allegheny Energy Supply Company, LLC,* 108 FERC ¶ 61,082 at P 12 (2004), *available at:* elibrary.ferc.gov/idmws/common/opennat.asp?fileID=10212209.

16 *Id.* at P 18 (citing *Boston Edison Co. Re: Edgar Electric Energy Co.*, 55 FERC ¶ 61,382, at 62,168 (1991)).

without fear of the process being "rigged;" (b) that a utility's own or its affiliate's bid will be selected only if it is truly the best option; and (c) that the wholesale sale is more likely to withstand FERC's scrutiny under the *Edgar* standards in determining whether the transaction is allowed to proceed under the Commission's market-based rate authority.

## III. Competitive Procurement "Lessons Learned" Stories

### A. <u>Georgia</u>

The State of Georgia has had mandatory competitive bidding procedures in place since the early 1990s. In January 2007, when Georgia Power Company ("GPC") submitted its integrated resources plan to the Georgia Public Service Commission ("GPSC"), in Docket No. 24505,[17] GPC also sought a blanket exemption from the state's competitive bidding procedures for all of its future baseload nuclear and coal capacity. In seeking this exemption, GPC offered no real justification for why its needs could not be met through a competitive RFP process. Rather, GPC asserted only that the existing RFP rules were insufficient to procure baseload resources, and presented unacceptable risks. A number of parties representing varying interests, including customer groups, wholesale suppliers, demand-side resources, and government entities intervened in the proceeding. Those parties universally opposed GPC's request for exemption from the state's competitive bidding processes. GPC subsequently withdrew its request for a blanket exemption, and instead sought at hearing a one-time exemption from the RFP procedures for the purpose of self-building two baseload nuclear units.

In a pleading in support of its request for a one-time exemption from the competitive procurement rules, GPC again failed to justify why it was unable to utilize competitive bidding procedures to address its power needs. GPC claimed that the specific exemption was needed to meet the 2016-2017 baseload requirement because there was insufficient time to meet the baseload requirement through the RFP process. That argument encountered fierce resistance in the proceeding, because it was GPC's refusal to initiate an RFP process that created the purported time pressure. GPC also claimed that its proposed project was "an extraordinary advantage for ratepayers that requires immediate action," without offering any factual support for that claim. Instead, GPC offered a "recitation of the evils that allegedly result from 'renting' instead of 'owning' baseload generating assets."[18] GPC claimed that a series of factors associated with the purchase of baseload power, rather than self-building baseload power, create "unacceptable risks" for utilities. These factors included "potential bankruptcy of a third-party power supplier; 2) obtaining replacement power for an expiring PPA; 3) managing the upgrade or expanding of a third-party supplier's facility;

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[17] *See* Georgia Power Company's Application for Approval for Approval of Its 2007 Integrated Resource Plan, Docket No. 24505-U, *available at:* http://www.psc.state.ga.us/facts/docftp.asp?txtdocname=99381.

[18] EPSA Brief, GA PSC, Docket No. 24505-U, filed June 21, 2007.

4) renegotiating a PPA when conditions change; and 5) ensuring reliability of third-party power suppliers."[19]

To the credit of the GPSC, the dispute was ultimately resolved through a unanimously approved settlement whereby GPC withdrew its exemption request, and instead agreed to issue an RFP to solicit offers to meet its power needs. Under the settlement, comprehensive, competitive and transparent RFP rules were established for purposes of identifying solutions to GPC's future power needs. The settlement states that GPC's RFP process "shall seek base load type resources with a clear preference for resources which provide ratepayers base load type benefits of reduced long term fuel risk." GPC is also required to submit its RFP documentation to the GPSC for prior approval before disseminating the RFP to potential bidders. An independent evaluator who will work with GPC and GPSC Staff to evaluate bids is also required under the settlement agreement.

### B. Colorado

Public Service Company of Colorado ("Public Service") has recently been involved in an active dispute before the Colorado Public Utilities Commission ("CoPUC") for either circumventing or ignoring the state's existing competitive procurement procedures by failing to utilize competitive bidding procedures required under the CoPUC's existing rules. In 2004, Public Service and other parties representing the various interests in the state entered into a comprehensive settlement that included a proposed 2003 Least-Cost Resource Plan, a 2005 All-Source RFP, and detailed bidding rules for the 2005 All-Source RFP. The settlement was submitted to the CoPUC in Docket Nos. 04A-214E, et al.[20] Under the settlement, Public Service was allowed to meet a portion of its power needs by constructing a utility generating facility on a sole-source, no-bid resource. The CoPUC approved that comprehensive settlement.

Only one year later, however, Public Service filed an application seeking to amend the 2003 Least-Cost Resource Plan to change the resource acquisition period from a ten year period to a nine year period. Public Service claimed that if it were required to fill its 2013 resource needs from bids submitted in response to the 2005 All-Source RFP, a baseload coal facility would be the likely choice. Public Service claimed that such coal facilities were uneconomic options.

The CoPUC denied the request, and admonished Public Service for seeking to change the resource acquisition period and for disregarding the bidding process established for the 2005 All-Source RFP. As the CoPUC pointed out, Public Service unilaterally decided not to even consider bids for 2013 prior to seeking approval of an amendment to the resource acquisition period. The Commission stated that Public

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19 *Id.* at 14.

20 See *Order Approving Settlement*, Decision No. C05-0049 of the CoPUC issued in Docket Nos. 04A-214E, *et al.* (Dec. 17, 2004) *available at*: http://www.dora.state.co.us/PUC/DocketsDecisions/decisions/2005/C05-0049_04A-214E_04A-215E_04A-216E.pdf.

Service's actions "called into question its commitment to the least cost plan process."[21] As the CoPUC stated, because of Public Service's actions in this regard, "there is no margin for error if new resources are to be built in time to provide electricity for the 2013 peak season."[22]

A number of potential bidders also reported to the CoPUC that Public Service had not acted in accordance with the bidding process established by the All-Source RFP and the Least-Cost Resource Plan. In particular, suppliers challenged both the methodology utilized by Public Service to determine whether the coal bids were indeed economic, and Public Service's unsupportable conclusion that the coal bids were indeed uneconomic. While the CoPUC recognized that Public Service had some discretion in consideration of bids, stopping the process and ignoring the competitive procurement rules went well beyond Public Service's discretionary authority.

In response to the CoPUC's own concerns, and the additional concerns expressed by potential bidders, the CoPUC initiated a complaint proceeding in order to gather additional information about whether Public Service "negotiated in good faith during the bid process," and whether Public Service violated the terms of the settlement. The CoPUC subsequently terminated the formal complaint process, but directed CoPUC staff to file a report of its investigative findings, and to propose rule changes to ensure that Public Service's actions with respect to its 2005 All-Source Solicitation RFP would not be repeated by Public Service or by other utilities in the state. Commission Staff concluded in its investigation that "it would be reasonable to question whether Public Service had acted in good faith," pointing to Public Service's "insistence on fixed pricing as the sole means of handling risk, the risk allocation in the model contract, the representation of bidders, and Public Service's history in the 2003 LCP." CoPUC Staff, however, conceded the limited value of its investigative findings, due to the CoPUC's termination of the formal complaint process. CoPUC instead focused its report on forward-looking measures to improve the state's competitive procurement processes.

In an Order issued in September 2007, the CoPUC adopted emergency rules governing the state's competitive procurement processes. These rules were adopted largely to address the issues by the CoPUC Staff's investigation of the 2005 All-Source Solicitation RFP. The CoPUC's new rules provided, among other things, that an Independent Evaluator must in the future be involved in competitive solicitations. The rules also affirmed that resources of all fuel types and technologies must be considered in a competitive procurement process, explaining that such a process must "afford all resources an opportunity to bid, and all new utility resources will be compared in order to determine a cost-effective resource portfolio."

This case study underscores the need not only for competitive procurement rules in place, but also mechanisms to both monitor and enforce those rules. As illustrated

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21 Decision No. C07-0165, Before the Public Utilities Commission of the State of Colorado, Docket No. 05A-543A, Adopted February 7, 2007.

22 Decision No. C06-0730, Before the Public Utilities Commission of the State of Colorado, Docket No. 05A-543A, Adopted June 7, 2006.

above, the absence of such rules can lead to situations where retail ratepayers are ultimately saddled with escalating costs and less reliable electric service.

### C. Oklahoma

On October 17, 2005, Public Service Company of Oklahoma (PSO) issued an RFP for up to 600 MW of baseload power. In response to the RFP, PSO received six bids, three of which were self-build proposals. The winning bid was submitted by the state's other large investor-owned utility, Oklahoma Gas and Electric Company (OG&E). OG&E's bid was for a conventional, subcritical coal-fired 950 MW generation unit, proposed to be owned jointly by OG&E and PSO. OG&E's bid included a cost of service pricing provision which did not conform to the pricing provisions of the RFP. Despite non-compliance with the pricing provisions of the RFP, PSO selected the plant proposal as the winning bid.

In July 2006, PSO and OG&E announced that they would jointly develop a 950 MW ultra-supercritical coal-fired power plant known as Red Rock, to be located on the site of OG&E's "Sooner" coal-fired generating facility. The announcement of the ultra-supercritical coal-fired plant was contrary to PSO's selection of a subcritical coal-fired unit as the winning proposal. The utility's decision to award the bid to OG&E and to jointly develop the Red Rock project with OG&E was essentially acceptance of a self-build project involving PSO's ownership of 50% of the proposed Red Rock plant. In selecting OG&E's bid and rejecting other bids, PSO rejected competing bids as uneconomic or as failing to comply with RFP requirements such as credit thresholds. Although PSO did competitively bid for generation, it selected a bid with a non-conforming pricing proposal and rejected a competitively priced option due to its concerns over debt imputation. OG&E, on the other hand, by-passed the competitive bid process entirely and chose to self-build a generation project without benefit of any competitive bidding process for a plant 50% of which its ratepayers would be responsible for.

At the time PSO issued its RFP, the Oklahoma Corporation Commission (OCC) had not yet issued formal competitive bidding procurement rules, although such rules were in the process of being developed and were approved by the Commission in a matter of months after the issuance of the RFP solicitation. Both PSO and OG&E were active participants in the rulemaking and had full knowledge of the Commission's intentions and efforts to develop rules for competitive bidding.

On December 21, 2005, PSO filed an application (PUD200600030) seeking a Commission determination that there was a need for PSO to acquire electric generating capacity and that such an acquisition would be considered used and useful. On January 17, 2007, OG&E filed an application (PUD200700012) seeking pre-approval to construct the Red Rock generating facility and authorizing a recovery rider. The OCC subsequently issued an order consolidating the two causes.

During the hearing a number of bidders to the PSO RFP raised a series of complaints regarding PSO's conduct of the RFP process, and the methodology used by PSO to evaluate certain bid costs. For example, PSO arbitrarily rejected certain bids as uneconomic, arguing that those bids should be discounted because of "debt equivalency" issues.[23] It should be noted that PSO used 100% of the proposed bid as a "debt equivalent", far in excess of allowances used in other states. Bidders also alleged that OG&E's bid was given preferential treatment, and that PSO failed to consider alternative technologies, such as natural gas-fired combined cycle facilities, as part of its RFP process.

The OCC rejected both PSO's and OG&E's pre-approval request for the proposed Red Rock project. Although the OCC agreed that both utilities had legitimate resource needs in future years, the OCC determined that there was not "sufficient evidence regarding the consideration of reasonable alternatives" when evaluating an application for pre-approval of either company's own generation projects.

PSO and OG&E abandoned their plans to develop the Red Rock project. Subsequently, each company filed individual requests to recover the costs associated with the Red Rock project.

Competitive Bidding Rules were permanently adopted in Oklahoma on July 1, 2006. The Competitive Rules establish a process to conduct an open, transparent and competitive RFP. An independent evaluator must monitor any RFP and competitive bidding processes in which: 1) the utility's affiliate is involved; 2) the resulting bid is expected to materially affect the utility's cost of providing electricity; or 3) the utility itself expects to participate in the process. The Rules also establish specific qualification requirements for affiliate bidders, and standards for evaluating responses to RFPs.

This case study illustrates the importance of explicit and detailed competitive procurement rules. Many states still do not have explicit competitive procurement mechanisms incorporated into their rules and regulations, even though they implicitly require utilities to test competitive options when identifying projects to meet their power needs. Without such explicit rules in place, utilities lack sufficient guidance or constraints on how best to meet their power needs, and time and money may be spent

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23 As noted in the section of this paper on California, State commissions have varying views regarding the legitimacy of even considering debt equivalency in competitive procurement decision-making and, if so, how to evaluate it. At the July 2007 meeting of the NARUC/FERC Joint Dialogue on Competitive Procurement, however, Todd Shipman, a Director at Standard & Poor's, said "the point I'd like to make on the purchase power adjustments is that they're often or sometimes referred to as being a debt equivalent or something like that. And we certainly don't see it that way. All of the adjustments that we make to bring something onto the balance sheet because we view it as being a debt-like obligation is recognized by our analysts and by the rating committees as being—that adjustment is not the same thing as the actual debt that companies have and that they need to pay off over time, hopefully. And so the real impact of the adjustment on the credit ratings of utilities can vary by utility and by the jurisdiction that they're in and it encompasses a whole—the credit analysis encompasses a whole lot more than just throwing $500 million onto their balance sheet as a debt equivalent or something like that. The overall impact of a utility's and the regulatory commission that regulates them—their policies and their conduct of the competitive procurement process among other things—all will get factored into the rating." Transcript of July 18, 2007 NARUC/FERC Competitive Procurement Dialogue Meeting, at 21.

pursuing nonviable projects. Such time and money spent ultimately harms ratepayers through increased rates and delayed development of needed power projects.

As part of PSO's RFP for delivery in 2012, the OCC has recently selected an independent evaluator – as opposed to the utility as was the case previously. The independent evaluator will work with the OCC and PSO in development of the RFP, serve as the conduit for all communications between bidders and the utility as well as oversee the selection of a winning bidder and provide a report to the commission. Recent developments such as these leave us cautiously optimistic that the events surrounding the Red Rock facility will not be repeated.

### D. North Carolina

In 2005, Duke Power applied to North Carolina Utilities Commission ("NCUC") for approval of two 800 MW coal units at a cost of $3 billion, stating that these units were needed to provide baseload capacity for the Duke Power system. Duke Power sought to satisfy its resource needs exclusively by self-building, rather than soliciting bids through a competitive RFP process. Duke Power claimed that the "self-build baseload option is the most reliable means for Duke Power to meet its service obligations in a cost-effective manner."[24] Yet, Duke Power submitted minimal evidence as to why competitive procurement might be impractical, or why the self-build option was a superior choice. Though North Carolina does not have formalized competitive procurement rules, a NCUC Commissioner has stated that "in such instances as a utility seeks to obtain authority to construct a new generating facility, one of the issues that must be addressed in that case is the extent to which the utilities self-[build] option has been tested against competitive alternatives...."[25]

In early 2007, the Commission determined that Duke Power had demonstrated a need for 800 MW of baseload capacity, rather than the 1600 MW it had requested.[26] In addressing Duke Power's proposal to self-build, the NCUC stated that it looked at various alternatives to Duke's proposal, and that each alternative was problematic. The Commission stated that, "without setting precedent for other cases, the Commission could not conclude that Duke should have issued an RFP for the capacity at issue herein." The Commission's determination accordingly tasked the intervenors in the proceeding with demonstrating why Duke Power should have issued an RFP, rather than requiring Duke Power to show why it should be allowed to procure capacity without an RFP.

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24 Preliminary Application for Certificate of Public Convenience and Necessity, Cliffside Project, Submitted by Duke Power on May 11, 2005 at the North Carolina Public Utilities Commission.

25 Transcript of July 18, 2007 NARUC/FERC Competitive Procurement Dialogue Meeting, at 7.

26 *See Order Granting Certificate of Public Convenience and Necessity With Conditions*, Docket No. E-7, Sub 790 (Mar. 21, 2007), *available at:* http://ncuc.commerce.state.nc.us/cgi-bin/webview/senddoc.pgm?dispfmt=&itype=Q&authorization=&parm2=ZAAAAA08070B&parm3=000123542.

The Commission subsequently approved Duke Power's application with respect to one of the two proposed 800 MW units, without requiring Duke Power to utilize the competitive procurement process, but rejected for the time being its application for the second 800 MW unit.

Since the initial announcement of this self-build project, Duke Power's cost estimates have increased dramatically. Duke Power initially stated that the two 800 MW coal units would cost a total of $3 billion. Only months later, during the application process before the Commission, Duke Power revised that estimate downward to a total cost of $2 billion. After the Commission approved Duke Power's application for a single 800 MW coal unit, Duke Power's estimate for the single-unit project spiked to $1.8 billion. More recently, on February 12, 2008, Duke Energy was quoted as saying that the 800 MW coal plant would cost $2.4 billion, i.e. substantially higher than the any estimate contained in either Duke Power's application to the Commission or elsewhere. This case study underscores the value of a competitive procurement process for "big ticket" items such as new baseload units. When the winning bidder in such procurements is a competitive power producer, that entity is held under most circumstances to the dollar amount of its submitted bid, and thus bears the risk of cost overruns on the project. By contrast, under a utility-build option, the regulated utility is usually able to pass through such cost overruns to its ratepayers and thus has little incentive to contain costs. This is a particular problem at a time when the costs of building new power generation projects have risen dramatically and are forecasted to continue to do so.[27]

### E. Louisiana

On July 11, 2007, Entergy Louisiana, LLC filed an application at the Louisiana Public Service Commission ("LPSC") for approval to repower Little Gypsy Unit 3 Electric Generating Facility, ("Repowering Project"). The Repowering Project was selected to meet long-term supply-side resource needs under the terms of an RFP issued by Entergy Louisiana's affiliate Entergy Services, Inc. ("Entergy") on April 17, 2006. The RFP was developed pursuant to the LPSC's Market Based Mechanisms Order, ("MBM Order"),[28] which includes the state's competitive procurement rules.[29] The

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27 Cambridge Energy Research Associates (CERA) found that power plant costs have increased 130% from 2000 to 2007, 27% in 2007 alone and 19% in the last six months of 2007. A power plant that would've cost $1 billion in 2000 would have cost $2.31 billion in 2007. (Power Capital Costs Index released Feb. 14, 2008) From 2002 to 2006 price of steel nearly tripled from $222/ton to $600/ton (Congressional Research Service, "Steel: Price and Policy Issues," Aug. 31, 2006, p. 20) The price of cement and crushed stone, both of which are used in large quantities in electricity infrastructure projects, rose by 30 percent between 2004 and 2006. (The Brattle Group, "Rising Utility Construction Costs: Sources and Impacts," Sept. 2007, p. 13)

28 General Order, Docket No. R-26172, Subdocket A, *In re: Development of Market-Based Mechanisms to Evaluate Proposals to Construct or Acquire Generating Capacity to Meeting Native Load, Supplements the September 20, 1983 Order*, (February 16, 2004).

29 Entergy Louisiana, LLC, Ex Parte, Order No. U-30192, Louisiana Public Service Commission (November 8, 2007), at 12.

2006 RFP sought proposals for combined cycle gas turbine generation resources ("CCGT") and other baseload resources.

To ensure that the RFP was conducted fairly, impartially, and in accordance with the MBM Order, Entergy hired two Independent Monitors (IM), a Process IM and an Evaluation IM, to "(1) oversee the design and implementation of the RFP solicitation, evaluation, selection, and contract negotiation process to ensure that it will be impartial and objective; and (2) provide an objective, third-party perspective concerning [Entergy's] efforts to ensure that all proposals are treated in a consistent fashion and that no undue preference is provided to any Bidder, including Entergy Competitive Affiliates and self-build and/or self-supply projects." As part of its RFP process, Entergy also utilized additional safeguards, such as requiring that all Entergy employees adhere to Entergy codes of conduct and affiliate rules, and employing an electronic process to segregate bid information and maintain confidentiality.[30]

In response to the RFP, Entergy received "35 CCGT [Combined Cycle Gasification Turbine] proposals from 9 bidders representing 12 generation resources and 9 baseload proposals from 6 bidders representing 7 generation resources."[31] Pursuant to the terms of the RFP, bidders were obligated to meet certain operational requirements, while providing Entergy with cost-effective, long term generation resources for its customers.

The submitted proposals were initially reviewed by the Process IM. As part of its initial review, the Process IM redacted certain information in the bid documents to ensure that the bid evaluators and decision-makers did not know the identity of the bidders. Both the Process IM and the Evaluation IM had various other oversight responsibilities to ensure that the bid submission and evaluation process would be conducted without preference towards affiliates or self-build projects. The evaluation and selection process for identifying the winning bidders considered "a range of price and non-price factors, including resource location, operating flexibility, transaction considerations, transmission, and fuel."[32]

Entergy's Repowering Project was chosen as the winning bid in early 2007. Both Independent Monitors testified that the evaluation process "was conducted in a manner that was fair and impartial to all bidders and gave no undue preference to the Repowering Project." In its RFP application, Entergy had initially represented that the total costs for the Repowering Project would be approximately $1 billion. Following the selection of the Repowering Project, however, Entergy submitted an updated cost estimate of $1.547 billion for the Repowering Project, over $500 million above the original estimate used to evaluate Entergy's self-build proposal. LPSC Staff and the Independent Monitors analyzed the benefits of the Repowering Project using the updated cost estimate, and determined again that the Repowering Project represented

30 *Id.*

31 *Id.* at 13.

32 *Id.*

the "most economic among the shortlisted baseload projects judged by the RFP team to be viable."[33]

At least one bidder, which competed unsuccessfully in the RFP process, has since criticized the RFP process. They claimed that, particularly with the updated cost estimates, it could have offered cheaper power than the Repowering Project. The bidder also pointed to the timing of the dramatic cost increase, questioning why the Repowering Project cost estimates rose so dramatically after the project was selected as the winning bid.

This case study is an example of the need for better governance over cost updates and "refreshed bids." The winning bidder of an RFP, particularly when the winning bid is an affiliate transaction, should not be allowed to update its bid unless all other RFP participants are afforded the same opportunity. Without such a rule, bidders are encouraged to "lowball" winning bids, and then to increase those bids after winning the RFP. Bidders would be able to hide significant costs in an initial RFP process, and then update those costs once the winning bid was chosen, even if a non-self-build alternative that was initially rejected turned out to be the best deal for consumers.

33 *Id.* at 14.

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# EMBRACE ELECTRIC COMPETITION OR IT'S DÉJÀ VU ALL OVER AGAIN

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This study was prepared by members of The NorthBridge Group, Frank Huntowski (Director), Neil Fisher (Principal), and Aaron Patterson (Principal). The NorthBridge Group is an independent economic and strategic consulting firm serving the electric and natural gas industries, including regulated utilities and companies active in the competitive wholesale and retail markets. NorthBridge has a national practice and long-standing relationships with restructured utilities in Regional Transmission Organization ("RTO") markets, vertically-integrated utilities in non-RTO markets, and other market participants. Before and throughout the restructuring process of the U.S. electricity industry, the authors have assisted clients with wholesale market design, competitive market analysis and strategy, regulated power supply procurement, state regulatory initiatives and strategy, and mergers and acquisitions.

# EMBRACE ELECTRIC COMPETITION
# OR IT'S DÉJÀ VU ALL OVER AGAIN

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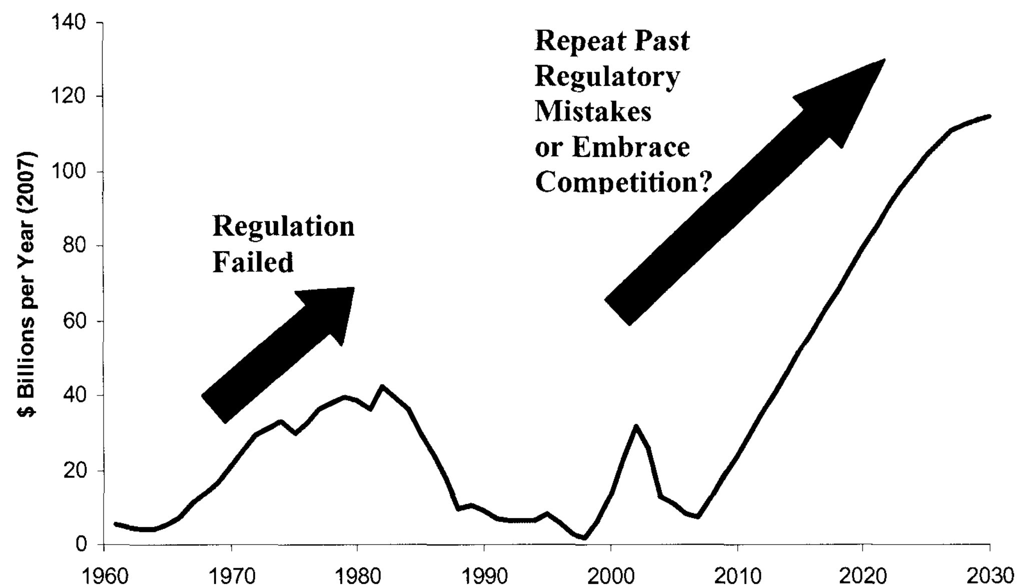
## I. Executive Summary

Our nation strives for "reliable, affordable, and environmentally sound energy,"[1] but the electric industry must confront enormous challenges to meet this goal. Construction and fuel costs to generate electricity have increased dramatically, and proposed Greenhouse Gas ("GHG") legislation is expected to further boost costs. Over time, the combination of decreasing GHG emissions targets and the nation's current carbon-intensive generation fleet is likely to create the need for one of the most significant capital realignments in the industry's history (see Figure 1). At the same time, the electric industry is embroiled in a debate about the relative merits of competition, and many believe that we should return to the "good old days" of regulation.

But we should not forget that electric regulation has faced similar challenges in the more distant past...and it failed. The 1970s was a time of huge increases in fuel costs, substantial capital cost escalation, serious environmental concerns, and unanticipated changes in customer demand. Regulation tried to tackle these challenges with an administrative, command-and-control decision-making process, but the result was a massive overbuild of baseload capacity, skyrocketing rates, large shareholder disallowances, and huge cost overruns paid by customers. In the end, the regulated response to the events of the 1970s and 1980s likely amounted to a mistake on the order of $200 billion or more in today's dollars and resulted in excess supply and high rates that were felt for decades.[2]

**Figure 1 Real Investment in Electric Generation, 1960-2030**




Source: See Figure 8 and Figure 17.

[1] National Energy Policy Development Group, "Reliable, Affordable and Environmentally Sound Energy for America's Future," May 2001, viii.

[2] This value represents the aggregate costs borne by customers and other electric industry stakeholders due to the failure to abandon high-cost nuclear plants and above-market contracts entered into as a result of regulatory interventions. See footnote 15 for more discussions.

A careful examination of the U.S. electric industry's response to the external shocks and uncertainty during the 1970s reveals four inherent flaws of regulation:

- **Lack of clear price signals:** The "price signals" to both suppliers and consumers in a regulated framework were the result of internal forecasts of a regulated entity subject to political influence and negotiation with the regulator during the ratemaking process. Later, when market conditions turned out dramatically differently than forecast, the lack of clear price signals contributed to a slow regulatory response marked by a failure to curb the over-building of baseload nuclear and coal capacity as costs spiraled and the need for capacity evaporated. As a result, the total U.S. reserve margin peaked at 42 percent in 1982, more than twice the 15 to 20 percent level generally deemed necessary to maintain system reliability. In terms of capacity additions, from 1970 to 1988, utilities added an average of 15,000 MW of coal and nuclear capacity per year (plus 4,400 MW of other capacity), while peak load grew by an average of only 13,800 MW per year.

- **Perverse capital incentives:** Regulated utilities had a tendency to favor large capital investments and consider sunk costs when making investment and abandonment decisions. These tendencies were on full display during the 1970s and early 1980s as regulated utilities continued to develop coal and nuclear plants long after those plants were clearly uneconomic in forward-looking terms. By 1980, the construction costs of nuclear power plants were approximately two to six times greater than the value of their output. Therefore, nuclear plants in the early stages of construction should have been abandoned, but more than 40 of these plants were eventually completed, which unnecessarily cost consumers hundreds of billions of dollars.

- **Improper allocation of risks:** Regulation improperly allocated risk (including the risk associated with technological choices, excess supply problems, and cost overruns) to consumers rather than to investors. Not surprisingly, the regulatory process significantly underestimated these risks when making long-term resource commitments. There are many examples of customer-funded commitments that turned out to be uneconomic.

- **Tendency for regulatory "fixes" to overcompensate:** Political and regulatory reactions to fix perceived problems tended to overcompensate with unintended consequences which further increased costs and inefficiencies. The turmoil of the 1970s led to a dissatisfaction with the existing regulatory process, and a search began for new regulatory solutions and models to counter the rate shocks experienced by consumers. The resulting administratively mandated qualifying facilities program burdened electric utilities and their customers with a $50 billion overhang of mandatory long-term contracts established at prices well above their actual avoided cost or any reasonable proxy of market prices.

None of these flaws were responsible for the shocks that placed the initial stress on the industry: the oil price shocks, cost inflation, and falloff in demand growth. However, the industry's response to these external shocks was heavily influenced by the flaws inherent in a cost-of-service regulation regime, and ultimately led to higher costs for consumers and less efficient resource allocation than likely would have occurred in a competitive framework.

In part due to these problems, the industry turned toward competition in the late 1990s. However, nationally the industry restructuring process has been lengthier and more difficult than many anticipated. Numerous studies, articles, and reports that have criticized competition focus on the recent rate increases in competitive states. But, for a number of reasons, such historical rate comparisons have limited value, especially as we look toward the future. Rates in regulated states, as in restructured states, have increased significantly since the late 1990s, and most of the increase in rates in restructured states occurring in the past several years can be traced to the expiration of rate freezes and the rise in natural gas prices. Further, rate increases in gas-dependent restructured and regulated states track one another very closely, and the magnitude of rate increases in particular states is closely related to the state's fuel mix and the rise in price of particular fuels. For example, had natural gas prices remained at the $3/MMBTU level as in the late 1990s, the rates in restructured states would have risen since then by about four percentage points less than rates in regulated states.

In the next twenty years, the industry will have dramatically different investment needs than it has had in the last ten years, and the true test of competition is still yet to come. The decision to support regulation or competition should not depend on the effects of external shocks (such as the recent rise in natural gas prices)[3] or whether regulated average cost prices are below or above market-based marginal cost prices at any particular point in time, but instead on whether a competitive or regulated model will foster more efficient decisions and ultimately better price and reliability outcomes over a sustained period of time and varying market conditions.

In spite of the recent criticisms, the case for competition in the electric industry is still compelling, supported both by economic theory and examination of empirical evidence:

- **Market prices provide the right price signals:** In a competitive market, market prices are a function of marginal costs, whereas regulated rates have traditionally been determined using "average cost" pricing. Over long time cycles, marginal cost pricing produces a more efficient and ultimately lower-cost outcome relative to regulated average cost pricing because it provides the correct price signal for the efficient allocation of new and existing generation and demand response resources. The level of market prices seen today are appropriate in that they provide the correct price signal and incentive for investment in the different types of low carbon resources that will be needed in the future.

- **Competition promotes efficiency improvements in:**

  - **Existing plant operations:** Competitive markets provide strong incentives to improve plant performance and administration in the short-term. Empirical evidence suggests that restructuring has improved the efficiency of power plant dispatch, extended the benefits of pooling and coordination across broader markets, reduced plant operating costs, increased baseload capacity factors, and reduced plant heat rates. Since 1999, nuclear plants operated by competitive

[3] Historical rate comparisons between restructured and regulated states would appear much more favorable to competition if natural gas prices remained at their level in the late 1990s, instead of increasing dramatically in the 2000s. See Figure 21.

generators have had an average capacity factor that is about two percent higher than that of regulated plants, producing savings of about $350 million per year. Restructuring also contributed to the substantial reduction in the average refueling outage for nuclear plants from 104 days in 1990 to 40 days in 2007, and has increased the average capacity factor for coal plants transferred from regulated to competitive owners from 59 percent to 67 percent.

- **Plant investment and retirement:** One of the most significant areas of potential savings from restructuring is more efficient long-term investments. Thus far, the industry has experienced significant restructuring of generating plant ownership. The experience of the gas combined cycle build-out in the competitive market of the late 1990s and early 2000s was very different from that of the regulated nuclear and coal capacity additions of the 1970s and 1980s as private investors responded much more quickly to changing market conditions. In response to the changing economics of gas combined cycle turbine plants, competitive builders cancelled 78 percent of capacity planned or under construction with a planned in-service date of 2003 or later while regulated builders cancelled only 37 percent of capacity. Unlike in the 1970s and 1980s, these uneconomic investments did not adversely impact customers in non-regulated states since unregulated investors – not ratepayers – bore the risk of these investments.

- **Customer consumption:** The competitive market price of electricity also provides a valuable price signal to customers that may affect customers' time of electricity use, overall level of electricity use, fuel choice, and investment decisions. Actions have been taken in restructured markets to increase economic demand response and expand market pricing to retail customers. High market prices that reflect environmental costs or peak demand periods will encourage reductions in consumption that will both reduce costs and greenhouse gas emissions. Specifically, some conservative estimates suggest that a 10 percent increase in the average price of electricity will result in a one percent or more decrease in electricity demand, which could decrease $CO_2$ emissions by 30 million tons per year and eliminate the need for nearly 5 gigawatts of new generating capacity, saving at least $10 to $20 billion in capital investment.

- **Retail competition is still developing and provides additional benefits:** Retail competition has developed to the greatest extent in restructured states where the market design allows the default price to reflect market prices. In several states, the vast majority of large commercial and industrial customer load is served by competitive retail providers, and the overall amount of customer switched load in the United States has more than quadrupled since 2001. Retail competition for residential customers thus far has developed largely in two states where market rules fostered competitive market development: broadly, in the ERCOT area of Texas and, less broadly, in New York. In Texas, more than 26 retail suppliers provide over 90 different residential products in each service area. Retail suppliers also provide "green" products, manage price and other risks, and offer load management and energy efficiency services that reduce and shift consumption during peak periods. In contrast, while default service rates that reflect market price levels promote retail competition, jurisdictions that have established fixed default service rates at below-market levels have virtually eliminated retail competition.

- **Other industries illustrate the benefits of competition:** The experience of other industries (e.g., airline, telecommunications, trucking) demonstrates that competition results in better utilization of resources, increased customer choice and access to new products and services, technological innovation, elimination of cross-subsidies, and lower prices.

To successfully navigate the confluence of an increasing public desire for environmentally-friendly resources with the rising cost of energy globally, participants in the electric industry must confront tough decisions and make difficult technological choices. The potential magnitude of future capital investments is unprecedented and the decisions required must be made in a highly uncertain environment with constantly changing information and significant risk. Decades of experience in the electric industry suggest that regulation is not well-equipped to meet such challenges. But recent experience in restructured electricity markets and significant experience in other competitive industries suggests that competitive markets are. We should learn from this history rather than repeat the regulatory mistakes of the past. By embracing competition, we can avoid "déjà vu all over again."[4]

[4] Yogi Berra, *The Yogi Book: I Really Didn't Say Everything I Said* (New York: Workman Publishing, 1998), 30.

## II. The Electric Industry Faces Enormous Challenges

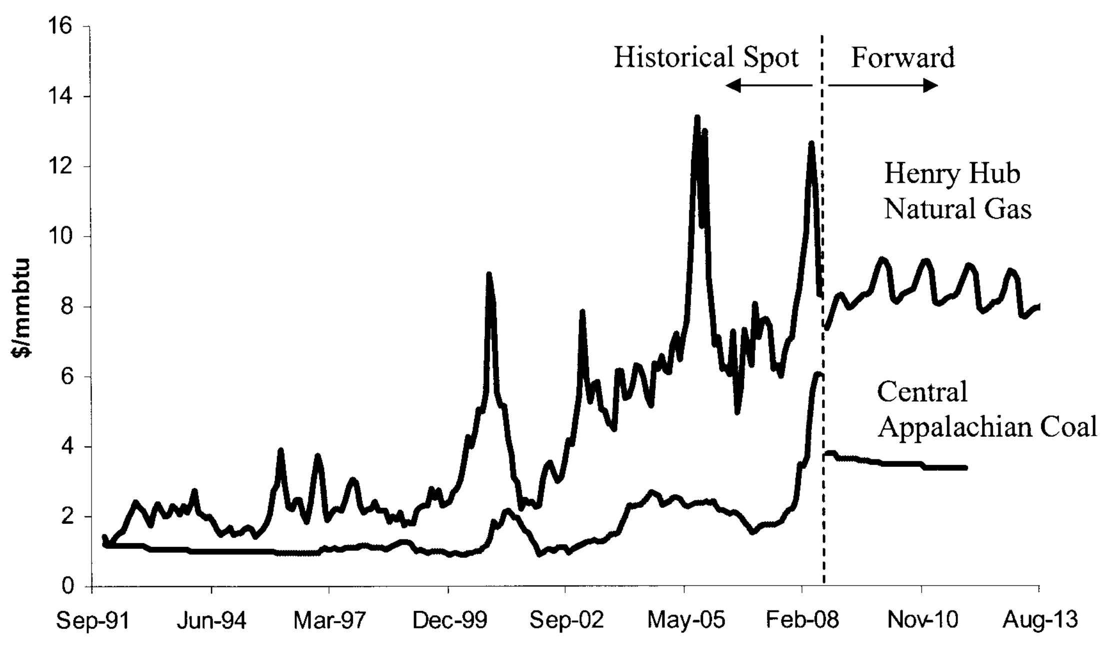
Looking forward, the electric industry faces a combination of significantly higher costs (both operating and capital) and massively increased need for capital investment, driven by ordinary load growth and, to an even greater extent, by the prospect of GHG regulation. Furthermore, a large degree of uncertainty and volatility will characterize the next twenty years: fuels markets and construction costs have become increasingly global and volatile, while the regulatory and technological uncertainties associated with carbon control are enormous. These conditions greatly increase the dollars at risk relative to recent history and will amplify any errors that are made in the coming years.

### A. The Cost of Electricity is Rising and Increasingly Volatile

Electricity generation is primarily a fuel conversion process. Coal, gas, oil, and uranium (and, to a lesser extent, water, wind, and other renewable fuels) are converted into electricity by an electric generating plant. Both the cost of the input fuels and the cost of the plant used to convert these fuels have risen significantly in the last few years. As a result, electricity prices over both the short-term and the longer-term have increased.

Roughly 95 percent of the generating capacity built in the past ten years uses either coal or gas as an input fuel. These fuels currently generate roughly 70 percent of the country's electricity needs. As shown in Figure 2, after a period of relative tranquility in the 1990s, these input fuel costs to produce electricity have increased markedly and have reached unprecedented levels.

**Figure 2 Increase in Natural Gas and Coal Market Prices, 1992-2013**

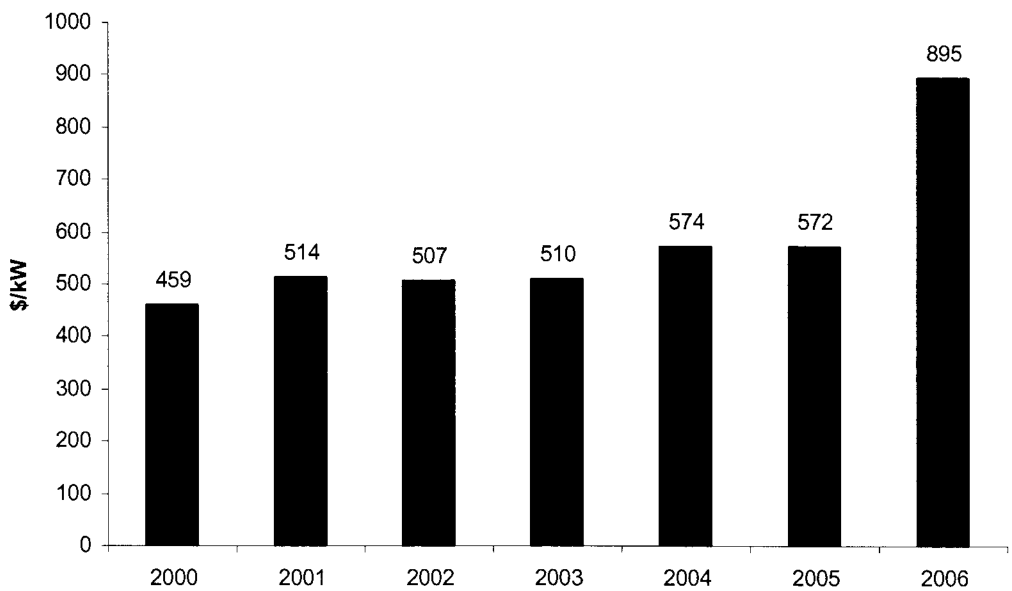



Source: Natural Gas: 1992-2004 – Bloomberg Daily Spot Price Assessment; 2005-2008 – ICE Day-Ahead Henry Hub Spot; 2008-13 – NYMEX Henry Hub Natural Gas Future (as of 9/15/08) Coal: 1992-2004 – Bloomberg Weekly Big Sandy Barge Spot Price Assessment; 2005-2008 – ICAP Prompt Month Big Sandy Forward; 2008-2011 NYMEX Central Appalachian Coal Forward.

Coal prices and natural gas prices have more than tripled since 1999. Current forward markets indicate that these relatively high fuel costs are expected to persist into the foreseeable future. Furthermore, fuel prices have also become more volatile: natural gas price spikes in the winter of 2000/01, in August/September 2005, and most recently in the first half of 2008 were at least twice as large as any price spikes seen previously.[5]

While fuel costs have increased, the cost to construct new power plants has also increased significantly in recent years, due to rising costs in materials and labor. The costs of steel and aluminum have grown by about 60 percent since 2003, and the costs of copper, nickel, and tungsten have tripled in the last few years. Primary drivers of these cost increases include increased global demand, increased production costs, and a weakening U.S. dollar. Labor costs, particularly costs for heavy construction and craft, have also increased at a rate much higher than inflation. As a result, the cost to build a new gas or coal plant has almost doubled over the 2000-2006 period. Figure 3 shows the increase in construction costs of a gas combined cycle turbine ("CCGT") plant since 2000.[6]

**Figure 3 Increase in Gas Combined Cycle Installation Costs, 2000-2006**




Source: The Brattle Group (Marc Chupka and Gregory Basheda), "Rising Utility Construction Costs: Sources and Impacts," prepared for the Edison Foundation, September 2007.

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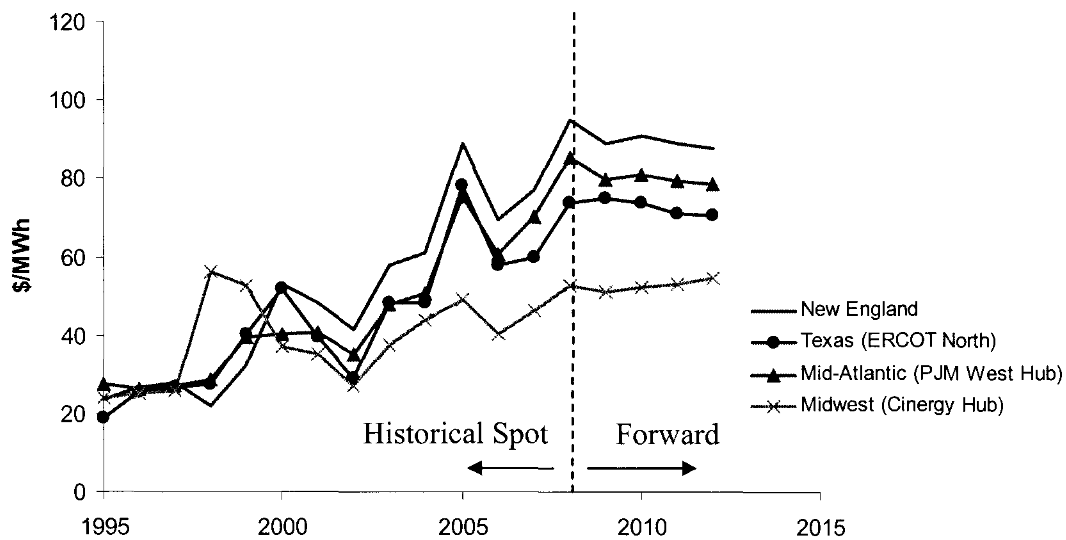
[5] While the reasons behind the increases in both natural gas price level and volatility are multiple and debated, there is consensus that the reserves of natural gas in North America have declined to the point where increasingly high-cost, marginal production sets the price for gas. In the long-term, the new-entry cost for liquefied natural gas ("LNG") will strongly influence the price for gas in North America, and this long-term price level is both relatively high and uncertain. Further, prices may exceed that level in the coming years, given the difficulty and time necessary to build new LNG import capacity.

[6] A more recent study from Cambridge Energy Research Associates suggests that these cost escalations have continued throughout 2007 and that the cost of all types of power plants as of early 2008 have increased by 130% relative to 2000, on average. ("U.S. Power Plant Costs Up 130 Pct Since 2000 – CERA," Reuters, 14 February 2008.)

These fuel and construction cost increases have caused wholesale electric prices to increase throughout the country, particularly in regions that rely heavily on gas-fired generation, such as in the Electric Reliability Council of Texas ("ERCOT") and New England, where wholesale electricity prices have increased by three to four times relative to the prices in the late 1990s. Other regions of the country have experienced significant price increases as well, as shown in Figure 4.

**Figure 4 Increase in Wholesale On-Peak Electricity Prices, 1995-2012**




Sources: Bloomberg Daily Spot Price Assessment for various regions; Megawatt Daily; ISO New England; Midwest ISO; PJM; Electric Reliability Council of Texas; New York Mercantile Exchange Forward Prices.

Wholesale electricity prices over the longer term will be a function of the total costs of new generation. Due to increased fuel and construction costs, the total costs of new gas and coal generation have nearly tripled and doubled, respectively, since 1999, as shown in Figure 5.

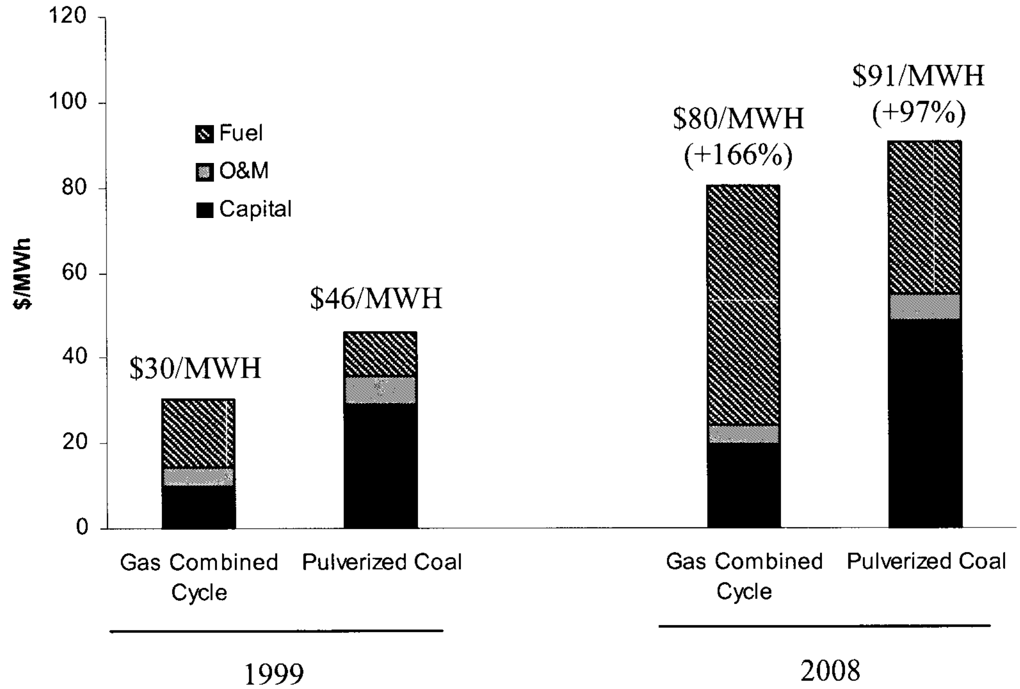
### B. Climate Change Concerns Are Becoming More Critical and Are Expected to Further Increase Costs and Require Significant Capital Investments

The challenges posed by climate change and GHG emissions[7] add an unprecedented level of uncertainty and complexity to the challenges faced in the industry. Concerns regarding carbon dioxide ($CO_2$) and other pollutants affect the ability to site and build new power plants and also increase the cost of operating existing power plants. Both regulated utilities and unregulated developers have found it difficult to build new coal plants in several areas of the

[7] Gases that trap heat in the atmosphere are often called greenhouse gases. Some occur naturally, but the principal greenhouse gases that enter the atmosphere because of human activities include $CO_2$, methane, nitrous oxide, and fluorinated gases or ozone-depleting substances. $CO_2$ is the GHG most relevant to the electricity generation sector because it is emitted by power plants that burn fossil fuels such as coal, oil, and natural gas.

country,[8] and builders of new capacity face new regulatory and environmental hurdles in a carbon-constrained world, which will continue to put upward pressure on the cost of building new generation.

**Figure 5 Increase in All-In Cost of New Build Generation, 1999 vs. 2008**




Notes: Based on construction costs of $500/kW and $1,500/kW for CCGT and PC, respectively, in 1999 and $1,000/kW and $2,500/kW in 2008. Assumes baseload operation for both plant types (90 percent capacity factor), 10 percent after-tax weighted average cost of capital, and 40 percent tax rate. Does not include any provision for carbon-related costs.

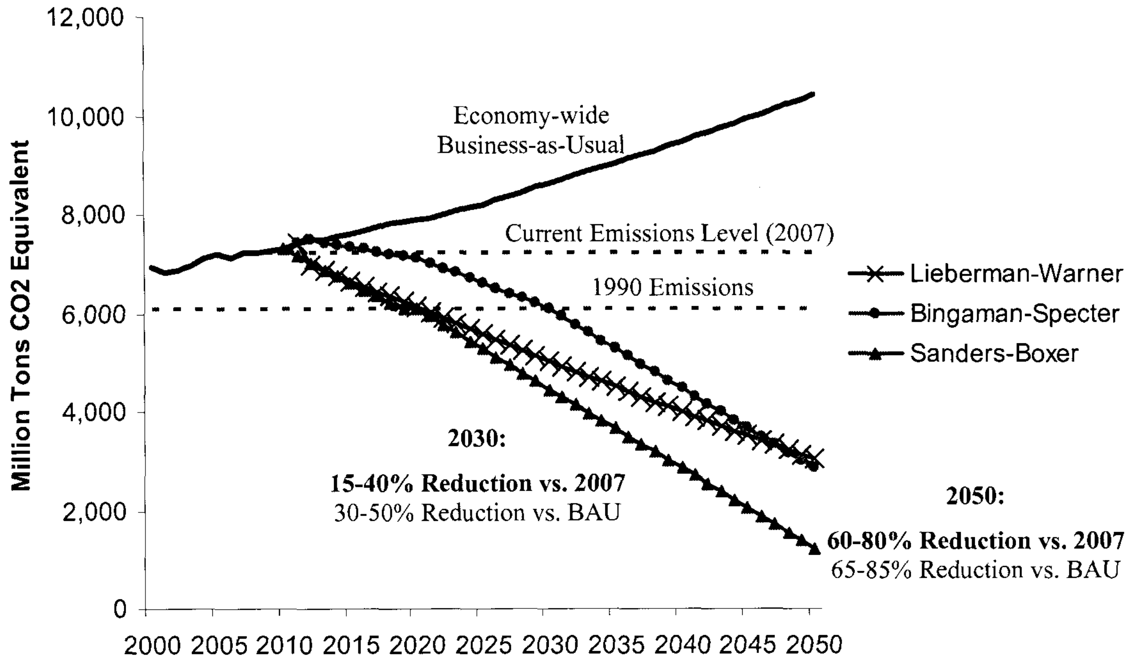
GHG regulation also will increase the cost of operating existing power plants. Most federal legislation being considered in Congress to control GHG emissions will place an explicit or implicit price on the right to emit $CO_2$ and other GHGs. This $CO_2$ price will be embedded in the marginal dispatch cost of $CO_2$-emitting generators, such as coal and natural gas fired generation plants, and will be reflected in wholesale electricity prices and generator costs. Thus, the economics of owning and operating existing capacity will change greatly under GHG regulation, along with capital investment incentives.

The recent concerns regarding new coal-fired plants are merely the opening act in what could potentially be the largest capital realignment in the history of the electricity industry, outdoing even the nuclear build-out of the 1970s. Most proposed GHG legislation in the United States contemplates extremely deep cuts in national GHG emissions by the 2030 to 2050 time frame. Figure 6 shows the mandated reduction path of the various proposals that have recently been advanced in the House and Senate. With few exceptions, all plans target a

[8] For example, Florida Power and Light shelved plans to build two gigawatts of regulated coal capacity due in part to environmental concerns. (Resource Media, "$45.3 billion in U.S. Coal-Fired Power Plants Cancelled in 2007: Rising Costs Force Energy Firms to Ditch Plans for 31 New Plants," Fact Sheet, 8 January 2008, 3.)

GHG atmospheric stabilization goal of 450 parts per million by 2050, implying reductions of 15 to 40 percent below the current U.S. $CO_2$ equivalent emission level by 2030, and 60 to 80 percent below the current level by 2050.

**Figure 6 GHG Reduction Targets of Proposed U.S. Legislation**




Source: Business-As-Usual Case: Energy Information Administration, Annual Energy Outlook 2008 with Projections to 2030, June 2008. Legislative cases based on NorthBridge analysis of relevant legislation.

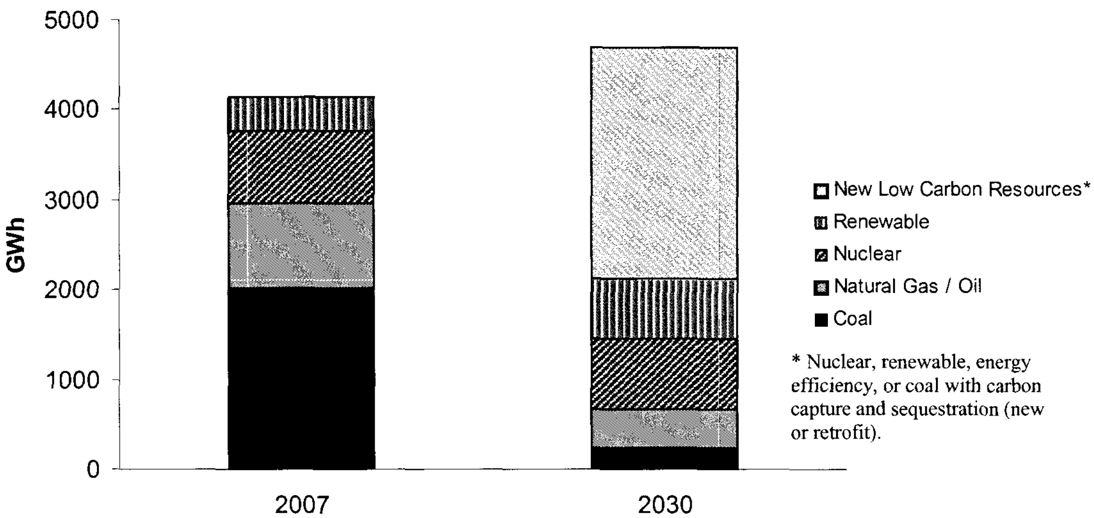
These emission reduction targets have enormous implications for the electric industry. The U.S. electric industry currently emits just under 2,500 million tons of $CO_2$ per year, or about one-third of total U.S. $CO_2$ emissions. Under the Energy Information Administration's "Business As Usual" projection, emissions are expected to rise to just under 3,000 million tons per year by 2030. If the electric industry bears a proportionate share of the emission reductions implied by the legislative proposals being considered (which is likely conservative since most models, such as the Energy Information Administration's National Energy Management System ("NEMS") model, suggest that the electric industry will bear a more than proportional share of emissions reductions), the industry must reduce emissions in 2030 by anywhere from 900 to 1,500 million tons relative to the "Business As Usual" amount. This reduction is equivalent to replacing between 250 and 400 average size coal units with zero-carbon capacity. The actual level of uncertainty is higher than that portrayed by this simple example: the relative costs of reducing emissions in other sectors of the economy and the degree to which the U.S. program is able to utilize international emissions reduction offsets add an additional layer of complexity. Achieving this emission reduction target will require that industry participants confront difficult resource decisions in the midst of tremendous uncertainty in future regulations, technology, and market conditions.

Unlike other types of pollutant regulation, there is currently no cost-effective, off-the-shelf means of reducing the $CO_2$ emissions of existing coal plants (such as Selective Catalytic

Reduction for $NO_x$ or Flue Gas Desulfurization for $SO_x$). Consequently, to stabilize and reduce $CO_2$ emissions, the industry must make some difficult choices and respond to shifts in technology. Current supply choices – which include retrofitting existing coal plants[9] and increasing reliance on low carbon technology such as nuclear, coal with carbon sequestration, wind, solar, and, to some extent, natural gas – appear to have very high costs. Reductions in customer demand for electricity also will be necessary, but not sufficient, to reduce $CO_2$ emissions to target levels. The costs of these potential alternative low-carbon strategies are extremely uncertain and likely to be high.

The capital realignment necessary to ultimately achieve the proposed reduction targets is unprecedented. Figure 7 shows the generation capacity investment necessary to satisfy projected load growth and a $CO_2$ reduction target of 30 percent below current levels by 2030 (consistent with the Lieberman-Warner Bill) assuming no generation retirements. In order to meet this target, the industry will need to reduce its usage of existing coal generation by more than 80 percent and build enough low-carbon baseload capacity (nuclear, coal with carbon capture, renewables, and energy efficiency) to generate 80 percent of the output of the current baseload fleet. Overall, this implies increasing the industry's existing generation capital stock by a factor of 50 percent once retirements are considered.

**Figure 7 Need for New Low Carbon Resources By 2030**



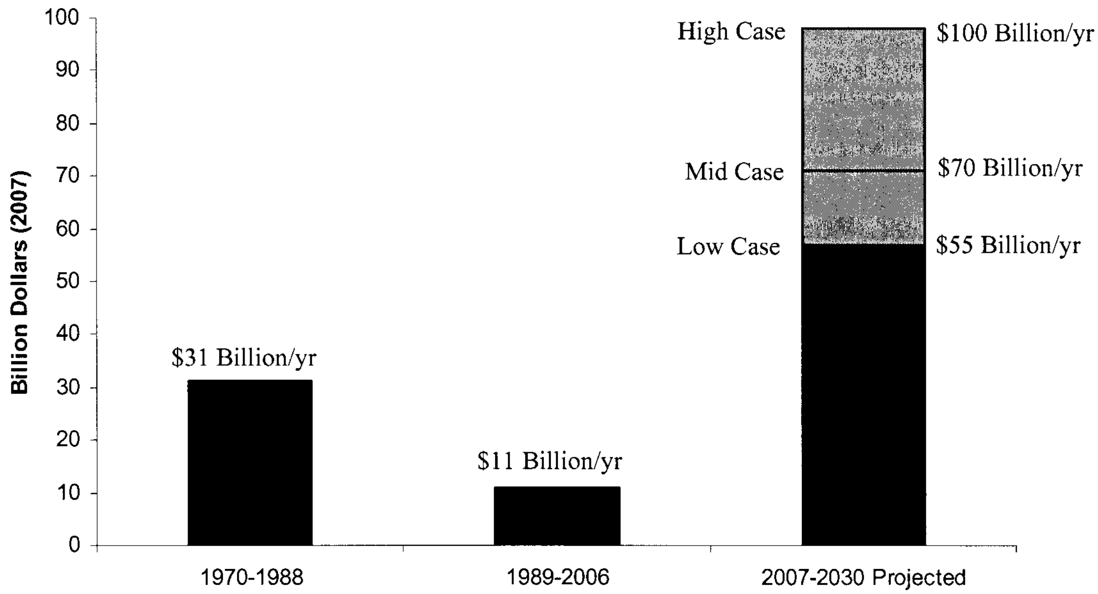

Source: Energy Information Administration, Energy Market and Economic Impacts of S. 2191, The Lieberman-Warner Climate Security Act of 2007, April 2008.

Figure 8 illustrates the financial impact of this capital realignment by comparing the average annual real generation capital investment from 2007 to 2030 with earlier periods. The required investment over the next twenty to twenty-five years will likely be five to nine times the level seen in the previous twenty years, and two to three times the level invested during

[9] In addition to any capital costs required to retrofit existing coal plants with carbon control technology, current estimates suggest that the output of these retrofitted coal plants would decline by 20 to 35 percent due to the carbon capture process.

the 1970s and early 1980s, when the industry built most of the nuclear and coal capacity in service today.

**Figure 8 Expected Increase in Annual Real Investment in New Generation**




Source: Edison Electric Institute, Historical Statistics of the Electric Utility Industry Through 1992; NorthBridge analysis based on Energy Information Administration, Energy Market and Economic Impacts of S. 2191, The Lieberman-Warner Climate Security Act of 2007, April 2008.

The political demand for non-polluting, low-carbon sources of energy is very high, as evidenced by the aggressive GHG legislation currently being considered. However, the available supply-side alternatives of meeting this demand are both costly and uncertain. The dollars at risk are as large as they have ever been in the electricity industry, and the decisions made over the next twenty years may very well have implications for electricity consumers reaching over the entire century.

## III. Regulation Has Failed to Meet Similar Challenges in the Past

While these future challenges loom large, the industry is currently embroiled in a debate about the relative merits of regulation versus competition. Rate shocks in restructured states such as Illinois, Maryland, and Connecticut have led some to question whether those restructured markets are producing an outcome beneficial to consumers. Concerns about high profits, market power, and market manipulation on the part of deregulated electricity suppliers began with the California energy crisis[10] and the Enron scandal and have continued as electricity prices have increased. Tighter generation reserve margins in many restructured states have led to fears that new competitive generation investment may not be sufficient to ensure electric system reliability.

In light of these concerns, some politicians and regulators are calling for a return to the "good old days" of regulation. But memories may be failing, because the good old days of regulation were not always good, especially during the times when the industry faced challenges similar to those of today. We should recall the 1970s, a time of tumultuous change in the electricity industry, when the industry first had to contend with an environment of sharply rising costs.

### A. The Challenges Faced in the 1970s Have Similarities to Those of Today

Many of the challenges particular to the 1970s eerily echo the challenges facing the industry today. In particular, both eras have in common three sources of shock and uncertainty: 1) rising fuel costs, 2) significant capital cost escalation and new environmental concerns, and 3) future electricity demand uncertainty. These external shocks were the primary forces behind the turmoil of the 1970s. Examining the response of the regulated industry structure to each of these shocks illuminates the shortcomings of regulation and the dangers of similar shocks in the electricity market today.

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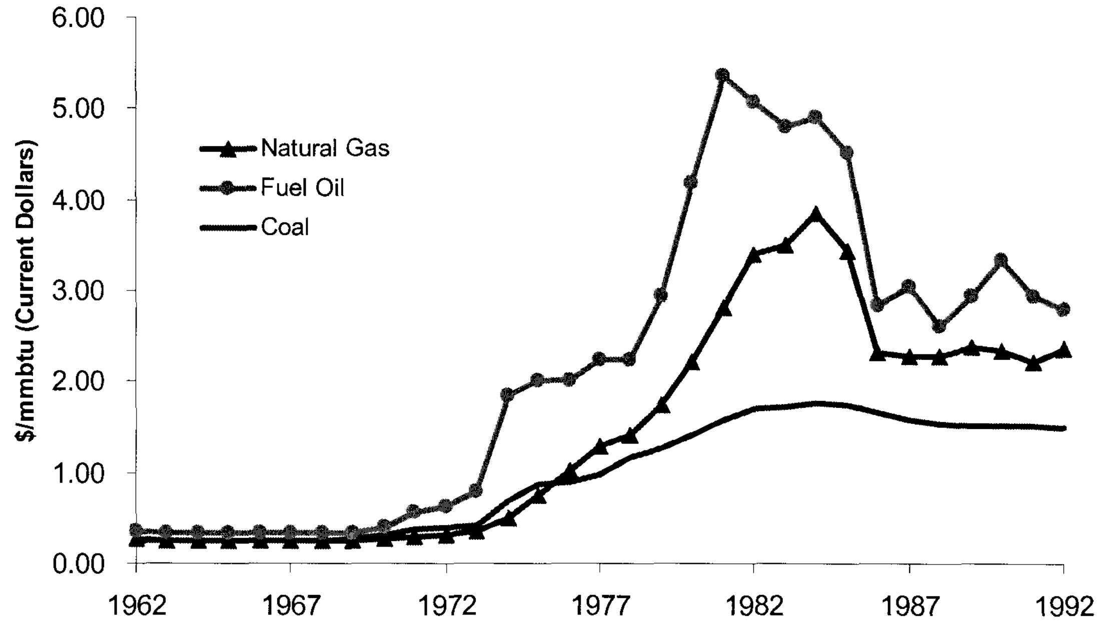
[10] In the summer of 2000, wholesale prices in California spiked above $1,000/MWH due to the convergence of several factors: hot weather with no demand response, limited supply from a capacity-constrained local market, a dry season limiting hydro-electric generation in the Pacific Northwest, high natural gas prices, and opportunistic behavior by wholesale suppliers. The high wholesale prices forced utilities to sell power to retail customers at prices far below their costs because there were no cost-recovery or rate adjustment mechanisms. The California market design left the utilities fully exposed to the spot market. Southern California Edison ("SCE") and Pacific Gas & Electric ("PG&E") had divested their fossil generating assets, and the utilities, as the provider of last resort, were to purchase electricity in high-priced spot markets and resell electricity to retail customers at lower, long-term fixed prices. This market design led to financial disaster for both companies, and ultimately large rate increases for retail customers. Dramatic price increases in late 2000 and early 2001 created a crisis that bankrupted PG&E and severely weakened SCE. PG&E and SCE suffered combined losses of billions of dollars in procuring power supplies to serve their load. As a result, retail access was halted, and the state government of California was forced to financially backstop procurement. Many economists and industry observers blame the California crisis on a flawed market design from a politically contentious regulatory and legislative process. (Frank Wolak, "Diagnosing the California Electricity Crisis," *The Electricity Journal*, Vol. 16, No. 7 (August/September 2003), 11-37; John Jurewitz, "California's Electricity Debacle: A Guided Tour," *The Electricity Journal*, Vol. 15, No. 3, (May 2002), 10-28; Paul Joskow, "California's Electricity Crisis," *Oxford Review of Economic Policy*, Vol. 17, No. 3 (2001) 6; Sally Hunt, *Making Competition Work in Electricity*, (Jon Wiley and Sons, New York: 2002), 378.)

1) Rising Fuel Costs

The dual shocks of the Arab oil embargo of 1973-4 and the Iranian revolution of 1979 caused world oil prices to rise to previously unprecedented levels in the 1970s. Natural gas prices and, to a lesser extent, coal prices followed suit. Figure 9 shows this rapid rise in the cost of input fuels for electric generators.

**Figure 9 Rise in Nominal Input Fuel Costs for Electric Generators, 1962-1992**




Source: Edison Electric Institute, Historical Statistics of the Electric Utility Industry Through 1992.

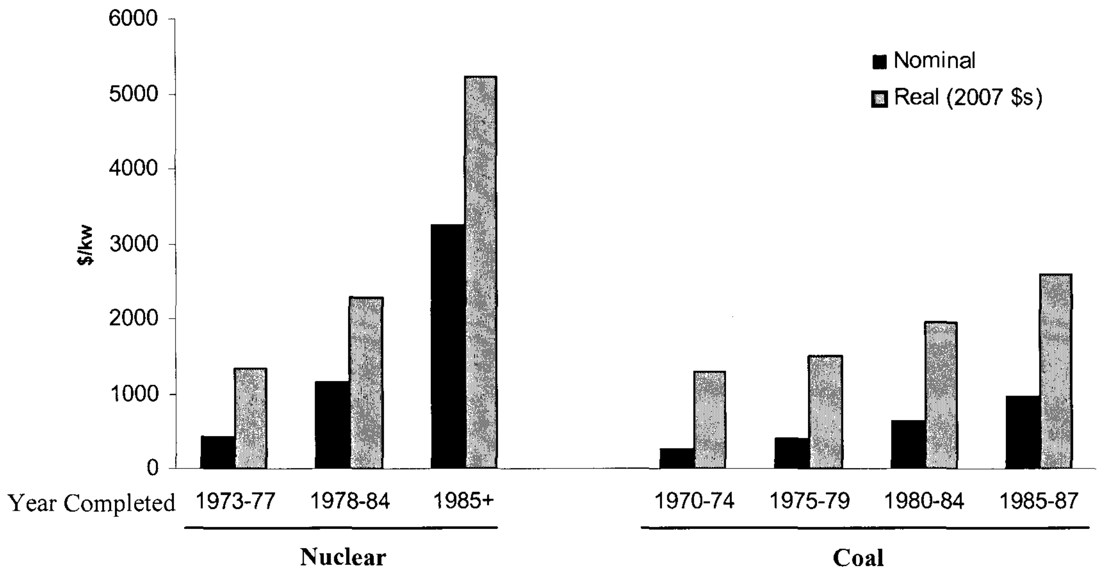
By 1982, coal, natural gas, and oil prices had risen to 6, 13, and 15 times their 1969 levels, respectively. As a consequence, variable generation costs for fossil fuel-fired power plants rose by a factor of 9 from 1969 to 1982. This increase led many utilities to develop fuel clauses that allowed the pass-through of higher fuel costs and/or contributed to numerous utility requests to increase rates.

2) Capital Cost Escalation and Environmental Concerns

Prior to the late 1960s, construction of new electric generating capacity had been characterized by increasing economies of scale. By increasing the size of power plants, utilities could achieve lower unit construction costs and greater thermal efficiency. This trend began to slow in the 1960s and essentially disappeared by the 1970s as reliability and economic dispatch problems associated with extremely large units began to appear. The average size of new coal units increased from 124 MW in the early 1950s to close to 600

MW in the early 1970s, but declined back towards 500 MW thereafter.[11] Around the same time, several legislative actions and market trends caused an increase in the cost of building and operating new power plants. In particular, the Clean Air Act of 1970 mandated that all new coal plants install equipment to reduce harmful air emissions, such as sulfur dioxide and nitrous oxide. Around 1973, the environmental movement also began to contest the construction and operation of nuclear plants, which led to construction delays, litigation, and increasing safety and environmental costs at nuclear units, a trend that intensified throughout the decade. The nuclear accidents at Brown's Ferry in 1975 and Three Mile Island in 1979 accelerated this trend, which ultimately led to long and expensive delays and re-designs for plants under construction throughout the late 1970s and 1980s. The costs of these delays in the construction and development cycle of coal and nuclear units were exacerbated by increasing input costs and inflation.[12]

**Figure 10 Escalation of Generation Construction Costs in the 1970s and 1980s**




Sources: Energy Information Administration, "An Analysis of Nuclear Power Plant Construction Costs," December 1986; Energy Information Administration, "Historical Plant Cost and Production Expenses For Selected Electric Plants, 1987."

All these factors put upward pressure on the cost of building and operating electric generation, with little or no offsetting gains in economies of scale and efficiency. Figure 10 shows the "overnight" construction cost per kilowatt of nuclear and coal-fired electric

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[11] Paul Joskow and Nancy Rose, "The Effects Of Technological Change, Experience, And Environmental Regulation On The Construction Cost Of Coal-Burning Generating Units," *Rand Journal of Economics*, Vol. 16, No. 1, (Spring 1985): 3, 4, and 24.

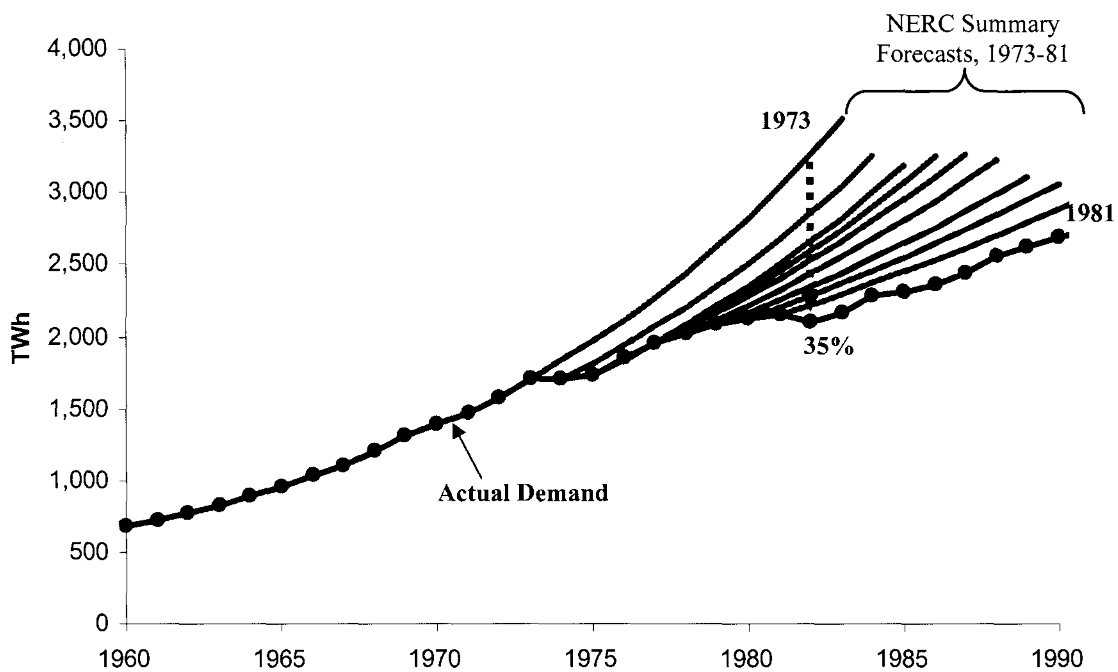
[12] Nominal construction costs for steam-electric power plants rose by 9 percent per year from 1973 to 1984, more than double the 4 percent per year increases from 1950 to 1973. (Based on data from the *Handy-Whitman Index of Public Utility Construction Costs*, Whitman, Requardt & Associates, various years.) Rising inflation, recession, and turmoil in financial markets also caused a dramatic increase in real and nominal financing costs. Nominal interest rates on utility bonds averaged over 11 percent from 1973 to 1984 compared to 6 percent from 1960 to 1972. (Edison Electric Institute, "Historical Statistics of the Electric Utility Industry through 1992," 1995.)

generation plants at different periods of time. Between 1970 and the late 1980s real and nominal nuclear construction costs increased by 113 percent and 679 percent, respectively, while real and nominal coal plant construction costs increased by 58 percent and 262 percent, respectively.

### 3) Demand Uncertainty

Prior to the early 1970s, demand for electricity grew at a rapid and fairly predictable clip. As Figure 11 shows, from 1960 to 1973 electricity consumption grew at an annual rate of 7.3 percent, with relatively little variance. Total electric generating capacity in this period grew by 7.7 percent per year, keeping approximate pace with demand growth. By the late 1960s, most utility demand forecasts reflected continued high load growth and a concomitant need for additional baseload coal and nuclear capacity. These demand forecasts buttressed a round of initial planning, completed between 1966 and 1973, for most units that were later built in the 1970s and 1980s. However, actual demand growth in the 1970s fell far below expectations. From 1973 to 1982 electricity consumption only grew by 2.4 percent annually, while generating capacity grew almost twice as fast at a rate of 4.5 percent per year. As Figure 11 shows, by 1982, actual demand was about 35 percent less than what it would have been had load continued to grow at its pre-1973 rate of growth.

**Figure 11 Actual U.S. Electricity Demand Fell Below Projections in the 1970s**




Source: Edison Electric Institute, Historical Statistics of the Electric Utility Industry Through 1992; Nelson, Charles, and Peek, Stephen, "The NERC Fan: A Retrospective Analysis of the NERC Summary Forecasts," *Journal of Business and Economic Statistics*, Vol. 3, No. 3, July 1985.

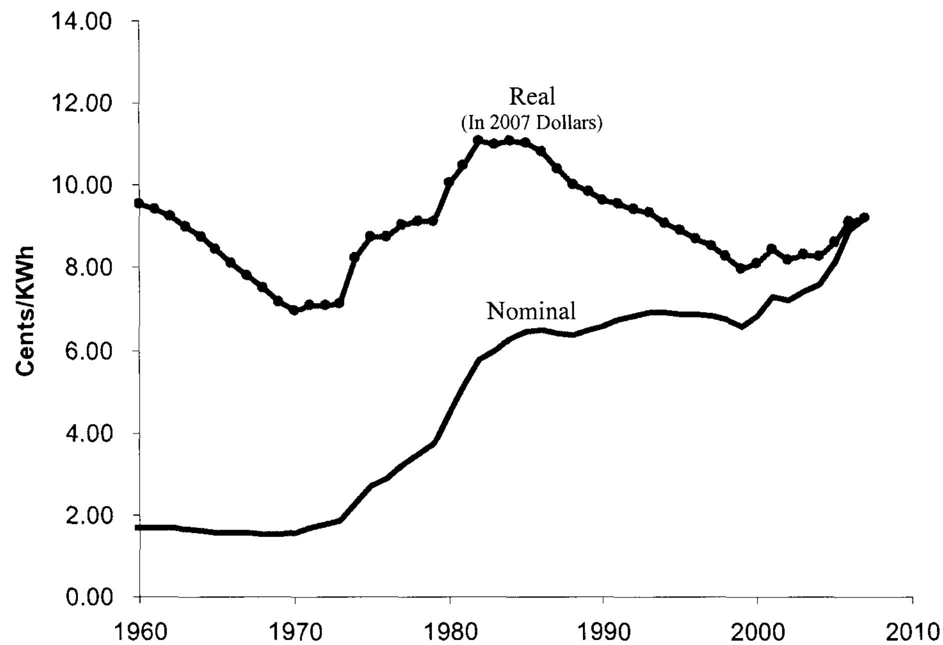
This falloff in demand growth was caused by a slowdown in the U.S. economy, a leveling-off of the nation's energy intensity,[13] and the inevitable demand response to higher electricity prices as rising fuel and capital costs eventually found their way into average-cost utility retail electric rates.

The overall effect of the lower-than-expected load growth was that the electric industry built up a huge oversupply of unneeded and expensive coal and nuclear capacity. The units built in the 1970s and 1980s were more expensive than originally estimated and the costs were spread over a smaller-than-expected customer base.

### B. The Regulatory Response to the Challenges of the 1970s Was Poor

The ultimate effect of these three challenges – rising fuel costs, capital cost escalation and environmental concerns, and demand uncertainty – and policymaker's response to them was to create an unmitigated disaster for electricity consumers and utility shareholders. As Figure 12 shows, the increasing economies of scale in the electric industry that led to lower retail prices in the 1950s and 1960s virtually disappeared by the 1970s. Nominal electric rates rose by over 300 percent from 1970 to their peak in 1985, while real rates rose by 60 percent in the same time period.

**Figure 12 U.S. Average Retail Electricity Prices Rose in the 1970s and 1980s**




Source: Edison Electric Institute, Historical Statistics of the Electric Utility Industry Through 1992; Energy Information Administration State-Level Spreadsheets, 1990-2006. 2007 rates are from December 2007 Energy Information Administration Electric Power Monthly.

[13] Energy intensity is a measure of the energy efficiency of a nation's economy that is generally measured in units of energy per unit of gross domestic product.

Electric utilities also endured approximately $60 billion in cost disallowances (in 2007 dollar terms) from the late 1970s to the early 1980s, costs which would have further raised rates had they not been borne by shareholders.[14] Overall, the regulatory response to the events of the 1970s and 1980s probably amounted to a mistake on the order of $200 billion or more in today's dollars.[15]

Figure 13 provides an indication of the misallocation of resources in the 1970s and 1980s. The figure shows capacity utilization for baseload coal plants from 1960 to the present. The economics of coal plants with high capital costs and low variable costs favor high capacity utilizations of 70 percent or more. In the 1960s and in recent years, coal plants have operated at this level of utilization. However, during the 1970s and 1980s, capacity utilization in the regulated electric utility industry remained low – at the 50 to 60 percent level.

When judged by the outcome of high electricity costs and low capacity utilizations, the regulatory response to the rising cost environment of the 1970s appears to have been a failure. But why was the response so poor? What portion of this poor outcome can be blamed on regulation, rather than exogenous shocks outside the control of industry decision-makers? And, would competition have produced a better result?

The external shocks that placed the initial stress on the electricity industry – the oil price shocks, cost inflation, and falloff in demand growth – were not caused by regulation of the industry. However, a careful examination reveals four inherent flaws of regulation behind much of the industry's response to the external shocks and uncertainty of the 1970s: 1) a lack of clear market price signals for both suppliers and consumers of electricity, 2) perverse capital incentives for regulated utilities to favor capital and consider sunk costs in investment and abandonment decisions, 3) improper allocation of risks that encourage regulated utilities to underestimate the risks of large capital-intensive investments that are borne by ratepayers, and 4) the tendency for political and regulatory "fixes" that overcompensate with unintended consequences. These flaws ultimately led to higher costs for consumers and a less efficient resource allocation than likely would have occurred in a competitive framework.

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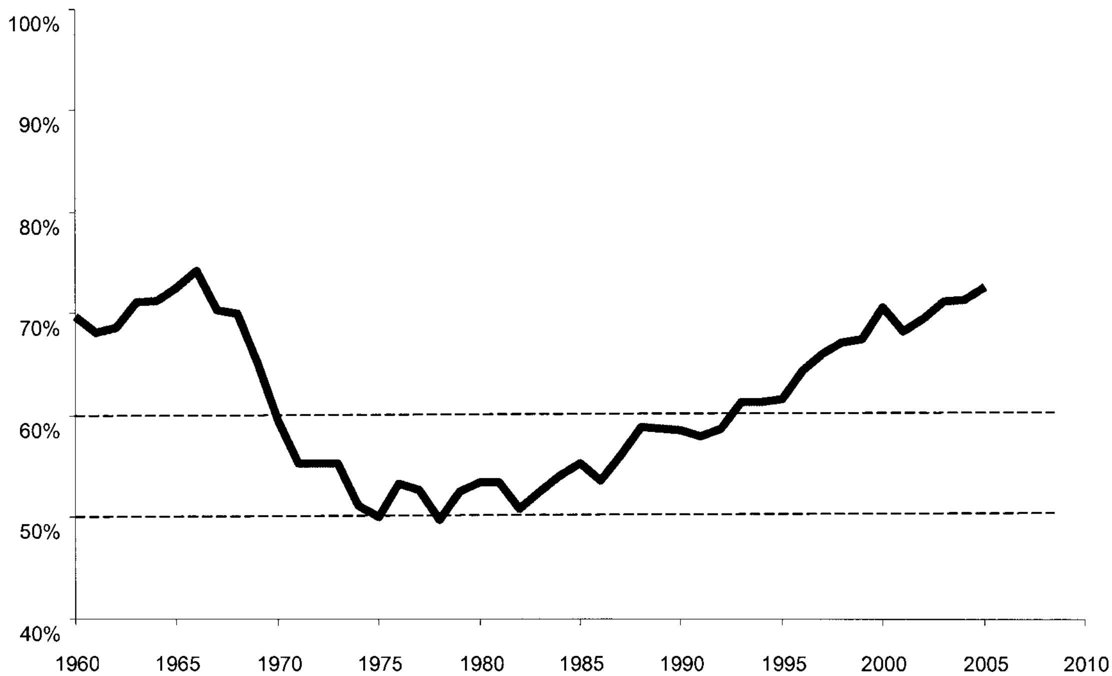
[14] Disallowances related to completed and in-service plants amounted to almost $31 billion in 2007$, or about $19 billion in mixed nominal dollars. (Thomas Lyon and John Mayo, "Regulatory Opportunism and Investment Behavior: Evidence from the Electric Utility Industry," *Rand Journal of Economics*, Vol. 36, No. 3, (2005): 628-644.) The other major source of disallowances was the sunk costs of abandoned nuclear units, which amounted to about $63 billion in 2007$, or about $36 billion in mixed nominal dollars. (Charles Komanoff, and Cora Roelofs, Komanoff Energy Associates, "Fiscal Fission, The Economic Failure of Nuclear Power," (December 1992), 15, Table 7.) These sunk costs were shared between ratepayers, utility investors, and taxpayers in a variety of ways depending on the jurisdiction. Assuming shareholders ultimately bore about half of these costs we arrive at a figure of about $60 billion in 2007$ for both sources of disallowances.

[15] This estimate is the summation of two sources of costs associated with the mistakes of regulation: the unsunk above-market cost of uneconomic nuclear units completed after the Three Mile Island incident, measured relative to avoided costs of fossil energy as of the early 1980s, and the above-market costs of uneconomic contracts entered into as a result of PURPA. We conservatively estimate the first source of costs at about $150 billion (in 2007$), while the second source has been estimated at close to $50 billion (also in 2007$) as of the mid 1990s (see Resource Data International, *Power Markets in the U.S.*, Boulder, CO, RDI, 1996). Note that these costs were shared among ratepayers, utility shareholders, and taxpayers.

**Figure 13 Capacity Utilization of U.S. Coal-Fired Electric Generation Remained Low During the 1970s and 1980s**




Sources: Energy Velocity; Edison Electric Institute, Historical Statistics of the Electric Utility Industry Through 1992; Energy Information Administration State-Level Spreadsheets, 1990-2006.

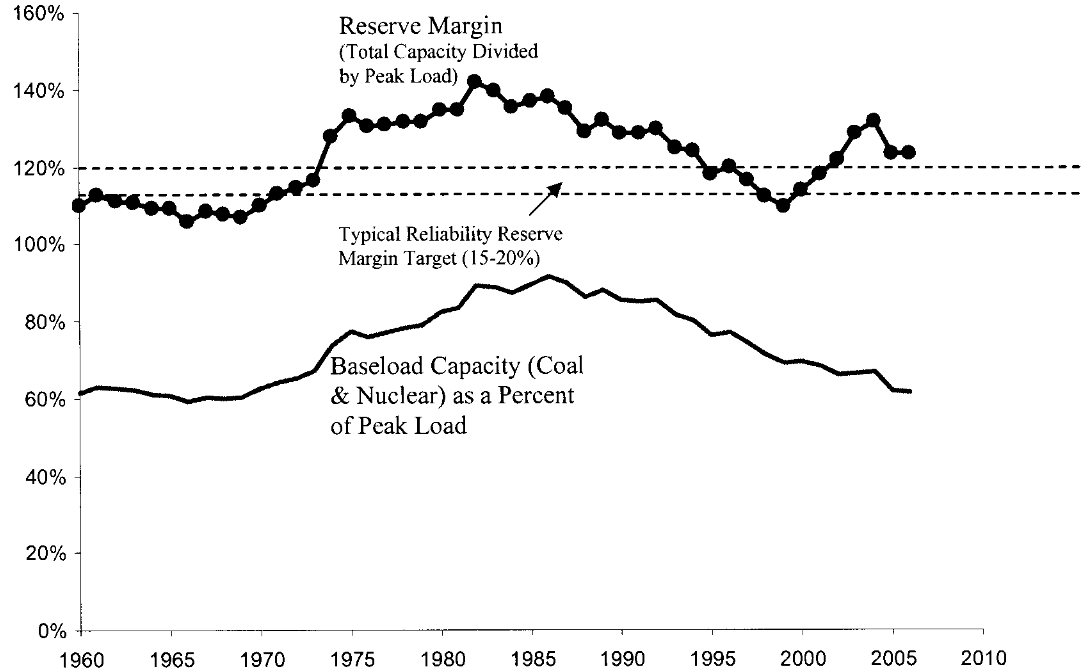
1) Lack of Market Price Signals

In the regulated-utility environment of the 1970s, utilities and regulators made generation resource decisions based on their long-term expectations about fuel prices, economic conditions, and supply/demand balances. These expectations were infrequently updated, and the "price signals" in this framework were the result of internal forecasts of a single regulated entity subject to political influence and negotiation with the regulator during the ratemaking process. Not surprisingly, such an approach can – and did – lead to poor resource allocation decisions, particularly during periods of market turbulence and uncertainty, where the relative economics of different resource types can change rapidly.[16]

[16] Today, the decision-making process regarding resource allocation is very different in a region with a competitive, visible wholesale electricity market. A competitive power plant developer considering the possibility of building a new plant is able to continuously evaluate the forward-looking economics of different types of generation using the various price signals generated by competitive markets. The price signal for revenues is the forward price of electricity that reflects a market consensus on future electricity supply and demand and the marginal costs of conversion of different fuels into electricity. The price signal for costs are the forward prices for different types of fuel (gas, coal, etc.) that reflect supply and demand conditions in those markets. The developer can meld these price signals into a continuously-updated picture of the relative economics of different types of generation and then act accordingly, along with other competing developers. Different developers may have different long-term expectations and different appetites for risk, but each

The generation resource allocation decisions of the 1970s clearly illustrate the shortcomings of decision-making without clear market price signals. During the 1950s and 1960s, capital and operating costs for nuclear and coal units were expected to be quite low (in fact, Lewis L. Strauss, chairman of the Atomic Energy Commission, famously proclaimed in 1954 that nuclear energy would be "too cheap to meter").[17] Not surprisingly, as reserve margins declined in the late 1960s, electric utilities initiated the development of a large number of nuclear and coal units. As the 1970s progressed, capital costs for these units began to rise, and demand growth failed to materialize, leading to a rapid deterioration of the economics of new generation in general, and baseload units (especially nuclear) in particular. Despite this change in economics, however, a large proportion of the excess baseload units planned in the late 1960s and early 1970s were ultimately built over the course of the 1970s and 1980s. In the period from 1970 to 1988, utilities added an average of 15,000 MW of coal and nuclear capacity per year, and 19,400 MW per year of capacity of all kinds, while peak load grew by an average of only 13,800 MW per year. Figure 14 shows the increase in U.S. reserve margin and the amount of baseload capacity as a percent of peak electric load during this period.

**Figure 14 Excess U.S. Reserve Margins and Baseload Capacity in the Mid 1970s to Early 1990s**




Source: Energy Velocity; Edison Electric Institute, Historical Statistics of the Electric Utility Industry Through 1992; Energy Information Administration State-Level Spreadsheets, 1990-2006.

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developer can monitor market prices and will need to bet its own money on decisions based on these differences in expectations and risks.

[17] Lewis Straus, Chairman of the Atomic Energy Commission, Speech to the National Association of Science Writers, New York City, 16 September 1954; "Abundant Power From Atom Seen; It Will Be Too Cheap For Our Children to Meter, Strauss Tells Science Writers," *New York Times*, 17 September 1954.

By 1986, coal and nuclear capacity reached 91 percent of national peak load, in comparison to approximately 60 percent today and in 1960. Similarly, total excess capacity as a proportion of peak load (i.e., the reserve margin) peaked at 42 percent in 1982, more than twice the 15 to 20 percent level generally deemed necessary at that time to maintain system reliability.[18] By the early 1980s, coal units, generally expected to have capacity factors greater than 70 percent, were operating at an average capacity factor of only 50 percent, indicating a large mismatch between the national generation supply portfolio and demand. As Figure 10 and Figure 11 show, both the falloff in demand and the escalation in generation capital costs were well underway by 1975 and were becoming readily apparent to utilities and regulators. However, utilities continued to overbuild baseload capacity well into the 1980s despite clear indications that such generation was no longer needed or economic.

Ultimately, over the course of the 1970s and early 1980s, electric utilities built a generation supply portfolio that was far too big in absolute terms, and too heavily-weighted towards capital-intensive coal and nuclear generation. The lack of clear market price signals was a significant culprit in this misallocation of resources. With no clear market pricing for electricity, utility builders and regulators lacked an unbiased indicator of future electricity supply and demand, and were thus slow to readjust their plans to build new generation as conditions changed. Furthermore, even when imperfect market price signals did exist, the command-and-control nature and perverse incentives of the regulatory process did not incorporate them well.

A more subtle problem was the lack of appropriate price signals for consumers of electricity. In the regulated utility framework, retail customers were charged a bundled rate that was based on the average historical cost of generating and delivering electricity to the customer. As such, the retail price incorporated the effects of numerous long-past decisions with respect to the historical costs and type of generation built by the utility. When the incremental cost of meeting load growth exceeded this historical embedded average cost (as it did in the rising cost environment of the 1970s and today) the retail price signal to customers was below the marginal cost of meeting the last increment of demand. Increases in retail rates lagged behind the increase in marginal cost. These artificially low price signals to customers encouraged over-consumption relative to the efficient level, which tended to exacerbate cost increases. While load growth did slow considerably in the 1970s and early 1980s relative to earlier periods (see Figure 11), it would have fallen faster and further had customers seen an appropriate marginal cost price signal.

Meanwhile, the lack of clear wholesale market price signals during this period led to poor resource decisions, in particular the over-build of regulated baseload capacity, which saddled the industry with the huge costs of oversupply.

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[18] Large-scale nuclear and coal units in the event of an outage tend to require a greater reserve margin than do a series of smaller-scale gas units and demand resources. As technology improvements enable smaller, more efficient plants to be built and there is increasing reliance on smaller customer demand resources in broader competitive markets, reserve margins should shrink while continuing to maintain or even enhance reliability. In recent years, many competitive markets (e.g., ERCOT and PJM) have been able to reduce their target reserve margins to the 12 to 18 percent range.

### 2) Perverse Capital Incentives

Several perverse incentives created by the regulated structure also contributed to the poor industry response to the challenges of the 1970s and early 1980s. In particular, regulated utilities in a cost-of-service structure have incentives to over-invest in capital,[19] overestimate consumer demand for electricity, or continue to build facilities even when costs have significantly increased or slow-downs in load growth no longer require the investment. Regulated utilities with regulatory prudence oversight have a tendency to consider sunk costs[20] when making investment/abandonment decisions.

In a competitive market, a power plant builder with a partially-constructed plant will compare "to-go" capital costs – without any sunk costs – to forward-looking profitability when evaluating whether to continue, delay, or abandon construction of the plant.[21] Removing sunk costs from the decision-making process helps participants avoid "throwing good money after bad" if the prospects for an investment sour after resources have been sunk into the investment. For a regulated electric utility operating under the traditional "prudent investment" and "used and useful" investment cost recovery standards, such decisions are very different. Canceling an under-construction power plant and never putting it into service makes it less likely that the utility will be able to recover the investment sunk into the plant prior to cancellation. Therefore, relative to a non-regulated developer, a regulated utility will tend to finish large capital investments and place them into service even if the investment becomes uneconomic on a forward-looking basis at some point along its development cycle. While the utility certainly risks disallowance on an uneconomic completed plant, this risk is lower than that of trying to recover the sunk costs of an abandoned plant. Utilities were forced to confront the unpalatable decision to either build unneeded facilities or cancel construction and face the daunting prospect of trying to recover from customers the already-sunk costs of facilities that would not be placed into service, thereby failing the "used and useful" regulatory principle of cost recovery. This tendency to "build no matter what" was on full display during the 1970s and early 1980s, as utilities continued to develop coal and nuclear plants long after those plants were clearly uneconomic in forward-looking terms.[22]

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[19] Economists Harvey Averch and Leland Johnson in 1962 demonstrated analytically that firms subject to rate-of-return regulation will have a tendency to overcapitalize and have a high capital to labor ratio. This phenomenon in the economics of utility regulation became known as the Averch-Johnson effect. (Harvey Averch and Leland Johnson, "Behavior of the Firm Under Regulatory Constraint," *The American Economic Review*, Vol. 52, No. 5 (December 1962): 1052-1069.)

[20] Sunk costs are unrecoverable past expenditures. These should not normally be taken into account when determining whether to continue a project or abandon it, because they cannot be recovered either way.

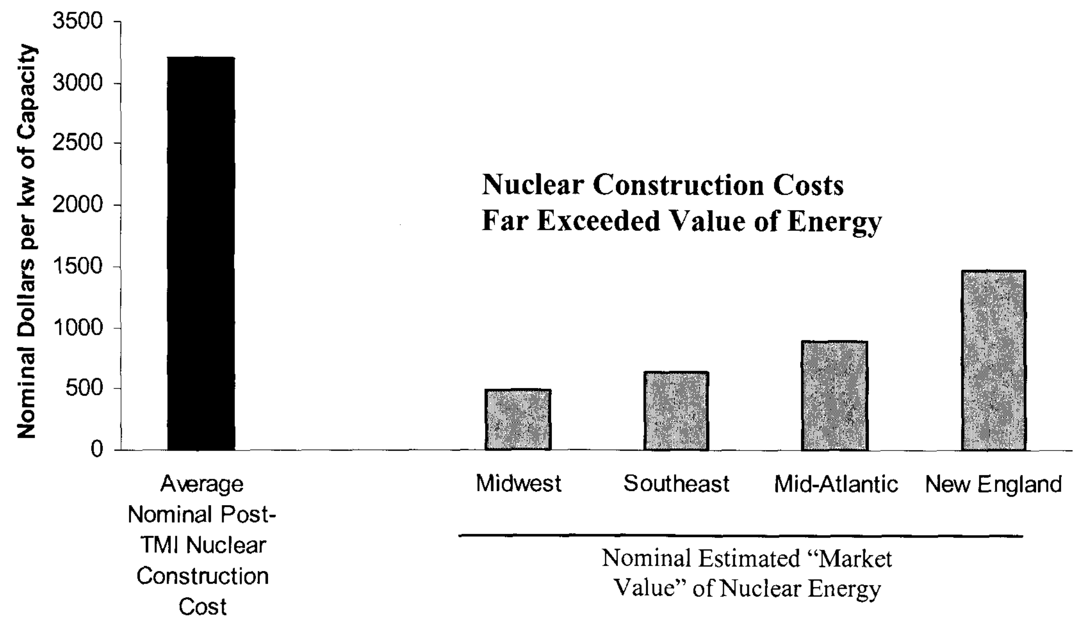
[21] Timothy Mount recognized this difference between regulated and merchant generators in a recent paper: "The important implication is that it is no longer realistic in a typical deregulated market to assume that a generating unit will be built after regulators have approved a license for construction. This was typically not the case under regulation. In a deregulated market, merchant generators have no obligation to complete projects if the prospects for recovering capital costs deteriorate during the construction process." (Timothy Mount, "Investment Performance in Deregulated Markets for Electricity: A Case Study of New York State," prepared for the American Public Power Association, September 2007, 28.)

[22] Further evidence of the tendency of regulated utilities to incorporate sunk costs into their decision-making has been found by examining the effect of nuclear plant cancellations on utility stock returns. For example, one analysis finds that utilities that cancelled nuclear plants under construction experienced significant negative excess stock returns. Furthermore, the larger the sunk costs relative to the size of the utility, the larger the stock price decline. This is consistent with the notion that cancelling a nuclear power plant under construction

For example, consider the situation in the nuclear industry in 1980. The Three Mile Island nuclear accident in March of 1979 led to a stoppage of new nuclear orders and a widespread questioning of the safety of plants in development.[23] The trend towards cost overruns and delays in the nuclear industry had been established for several years[24] and was likely to worsen in the current environment. Furthermore, it was apparent by that time that the country had reached a state of significant oversupply of generation, and that new nuclear plants were not needed – reserve margins had pushed above 30 percent by the mid-1970s and coal plant capacity factors averaged under 50 percent by 1975.

Figure 15 illustrates the forward-looking economics for nuclear power plants at the time by comparing nuclear plant construction cost to the approximate avoided cost of electric generation at the time in different regions of the country.

**Figure 15 Nuclear Investment/Abandonment Decision, Circa 1980**




Notes: Average nuclear construction cost based on data from Energy Information Administration, "An Analysis of Nuclear Power Plant Construction Costs," 1987. Market value of nuclear energy developed by estimating the nominal variable cost of energy produced from fossil fuel sources in each region, based on 1981 realized electric utility natural gas, coal, and oil costs.

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destroys value for the utility because it increases the likelihood that the utility will not be able to recover the sunk investment whereas taking the plant to completion provides at least some chance of recovering a portion of the investment. (Douglas Hearth, Darryl Gurley, and Ronald Melicher, "Nuclear Plant Cancellations: Sunk Costs and Utility Stock Returns," *Quarterly Journal of Business and Economics*, Vol. 29 (January 1990).)

[23] On March 28, 1979, a main feedwater pump malfunctioned at the Three Mile Island Generating Station near Middletown, Pennsylvania. A series of mechanical and human errors led to the most serious nuclear power plant accident in U.S. history.

[24] For instance, operations and maintenance costs for existing nuclear units, which is a barometer of the costs and difficulties of nuclear operations, rose in real terms by 73 percent from 1974 to 1979 and 137 percent from 1974 to 1980. (Energy Information Administration, "An Analysis of Nuclear Power Plant Operating Costs: A 1995 Update," April 1995, 7.)

By 1980, the construction costs of nuclear power plants were approximately two to six times greater than the value of the energy they provided. Put differently, only plants that had already sunk at least three-quarters of their likely final cost should have continued construction, and the rest should have been abandoned. Unfortunately, this did not happen. Ultimately, 53 nuclear units under construction at the end of 1979 were eventually completed, and of those, around 44 were less than 50 percent completed by 1980 (74 units on order were ultimately cancelled after 1979).[25] Six units were not completed until the 1990s. The costs associated with these decisions ran into the hundreds of billions of dollars and contributed greatly to the rise in rates in the 1970s and 1980s.[26]

3) Improper Allocation of Risks

Regulation improperly allocates risk between generation-building utilities and their customers. Prior to the 1970s, cost disallowances were virtually unknown in the electric utility industry. Should a generation facility prove uneconomic, the regulated model strongly suggested that the customers, rather than investors, would bear the risks of bad outcomes. Thus, there was little downside, and a great deal of upside, for utilities to bet large chunks of capital on big, capital-intensive baseload plants in the early 1970s. Customers still paid for the facility regardless of whether it was needed or not. The eventual disallowances of the 1970s and 1980s changed this calculus somewhat, but the risk distribution was still asymmetric, with customers paying for the majority of uneconomic capacity.

Not surprisingly, this inefficient allocation of risk creates an incentive problem for regulators and regulated utilities to underestimate risks, particularly risks associated with large baseload investments. The electricity supply business is inherently risky, because the future is uncertain with respect to those things that will determine the future market price of wholesale power: load growth, fuel prices, environmental costs, new technology, and so forth. For example, currently there is considerable uncertainty regarding the future cost and performance of new Integrated Gasification Combined Cycle (or "IGCC") plants, carbon capture sequestration technologies, and the costs and regulation associated with building new nuclear facilities. Therefore, large capital-intensive investments in new generation are unavoidably risky. Utility-built generation under a regulatory model or utility long-term contracts backed by ratepayer guarantees does not alter this fact – it merely shifts risks from the wholesale developer/supplier of generation to retail customers. In these risky electricity markets, unfavorable and unforeseen investment outcomes are common. Unfortunately, retail customers bear the responsibility of paying for those mistakes under regulation, while in competitive markets investors are responsible for the consequences of their decisions. Therefore, investors in competitive markets are more likely to respond quickly to changing market conditions than a regulated utility that can pass through its costs to retail customers. Indeed, under a regulated model of resource planning by utilities or regulators, with market risks assumed by customers, there have been many examples of long term generation commitments that turned out, after the fact, to be uneconomic. Whether the utility's commitments were in the form of utility-owned generation or long-term power purchase

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[25] Energy Information Administration, "An Analysis of Nuclear Power Plant Construction Costs," 1987.

[26] See footnote 15.

agreements, they were undertaken on behalf of ratepayers and were eventually paid for by ratepayers.

### 4) Political and Regulatory "Fixes" Overcompensate With Unintended Consequences

The turmoil of the 1970s led to a dissatisfaction with the existing regulatory process, and a search began for new regulatory solutions and models to counter the rate shocks experienced by consumers. Politicians and regulators then tried to "fix" some of the perceived imbalances in the energy industry. Related to the rise in fuel prices was an increase in concern that the nation's fuel supplies, oil and natural gas in particular, were insecure and limited in quantity. This concern led to a flurry of legislation and policy aimed at reducing the nation's dependence on oil and gas and promoting conservation, rationing, and end-use energy efficiency.

The most significant legislative response to the problems of the 1970s was the National Energy Plan, developed by the Carter administration and passed by Congress in 1978. The Plan actually consisted of several related pieces of legislation, the most important of which for the electric utility industry were the Power Plant and Industrial Fuel Use Act ("PIFUA") and the Public Utilities Regulatory Policy Act ("PURPA"). PIFUA and PURPA had unintended consequences that greatly influenced the course of the electricity industry through much of the 1980s and 1990s.

PIFUA was the culmination of a series of regulatory interventions in natural gas markets and federal restrictions on the development of gas-fired generation. PIFUA essentially prohibited development of new gas and oil power plants,[27] encouraged the conversion of gas/oil plants to coal, and limited the ability of utilities to run their gas/oil plants on a day-to-day basis. Starting in the 1950s, natural gas was subject to a complex regime of price controls that capped prices below their competitive market clearing levels and greatly limited the incentive to develop new gas supply. Exploration for new sources of gas production slowed, and the industry began to experience shortages by the mid-1970s. This regulatory interference with the gas market coupled with the federal restrictions placed on the use of gas as a power plant fuel (the Energy Supply and Environmental Coordination Act of 1974 and PIFUA in 1978) virtually eliminated natural gas as a viable fuel source for new generation, essentially forcing utilities to rely on coal or nuclear plants. While utilities were building up a huge surplus of coal and nuclear capacity, they also substantially reduced investment in less capital-intensive gas and oil capacity, building only about 2,400 MW, or about 2 to 4 plants, nationwide per year after 1975. Several studies of the natural gas industry have concluded that eliminating natural gas price controls and restrictions on gas-fired power plant investment would have provided a clear price signal and incentive to gas producers to increase production and develop new supply sources, ultimately lowering gas prices and potentially making natural gas a viable, cheaper alternative to much of the baseload generation developed in the 1970s and 1980s.[28] When gas prices were eventually decontrolled and PIFUA was scrapped, the

[27] There were exceptions in specific cases to maintain system reliability, and, after 1978, to promote the development of non-utility cogeneration facilities.

[28] Paul MacAvoy, *The Natural Gas Market: Sixty Year of Regulation and Deregulation*, (New Haven: Yale University Press, 2000).

incentive to build gas-fired generation did indeed develop. Ultimately, over the course of the 1970s and early 1980s, regulated electric utilities built a generation supply portfolio that was far too big in absolute terms, and too heavily-weighted towards capital-intensive coal and nuclear generation.

PURPA's stated purpose was to encourage energy efficiency in an environmentally-friendly manner by increasing the usage of alternative, renewable electricity generation.[29] To achieve these goals, PURPA created a new class of power generators called Qualifying Facilities ("QFs") that were exempt from most of the cost-based regulation applied to utility generation. To be deemed a QF, a power generation facility had to demonstrate that it was either a cogeneration plant or a small renewable generator. Utilities were required to purchase all the electric energy that these QFs could generate at the utilities' "avoided cost," which PURPA ambiguously defined as the incremental cost to the utility of alternative electric energy. PURPA did contain some innovative elements that, in time, were to contribute to the transition of the industry towards a competitive model; most notably, it created a class of non-utility generators that built and operated power plants outside the cost-of-service regulated model. However, the command-and-control elements of PURPA, especially the mandatory nature of the utility obligation to purchase QF energy and the administratively-determined purchase price, would prove enormously costly to electricity consumers.

The first five years after the passage of PURPA were spent determining what the "avoided cost" principle established in the legislation meant in practical terms. Even after the Federal Energy Regulatory Commission ("FERC") defined avoided cost in 1980, state regulatory bodies were charged with developing long-term avoided cost forecasts to set the prices for the QF contracts. While the process of establishing prices and structuring contracts varied considerably from state to state, prices were administratively-determined, not market-based, and several key mistakes were made:

- In some states, contract rates were established above avoided costs in order to spur QF development. For example, the New York state legislature mandated that the states' utilities pay a minimum 6 cents/kWh long-term price to QFs,[30] even though utilities

[29] "PURPA began the process of creating an independent generation sector and the supporting market and regulatory institutions to create a competitive market for new generating resources. The primary motivation for PURPA was to encourage improvements in energy efficiency through expanded use of cogeneration technology and to create a market for electricity produced from renewable fuels and fuel wastes. It was not motivated by a desire to restructure the electricity sector and to create an independent competitive generation sector. However, it turned out to have effects significantly different from what was intended when it was passed." (William Baumol, Paul Joskow, and Alfred Kahn, *The Challenge for Federal and State Regulators: An Efficient Transition from Regulation to Competition in the Electric Power Industry*, (Washington, DC: Edison Electric Institute, 1995) 8.)

[30] In New York, beginning in the 1980's in an effort to reduce reliance on utility-owned generation, the Public Service Commission ("PSC") required utilities to enter into contracts with non-utility generators at long-term fixed rates that were well above market prices. The New York Public Service Law was amended in 1981 to set the minimum sales price for the QFs' output at six cents/kWh. In practice, the PSC provided independent power producers the choice of six-cents or a fixed price stream equal to the PSC's estimate of long-run avoided costs ("LRACs"). The PSC's estimate of LRACs during the 1980s expected prices to rise well over six cents, and the PSC required that utilities provide the QFs with contracts of ten to fifteen years. Further, since the six-cent law provided no limit on the quantity of generation that could qualify for power contracts, QF developers planned projects with total capacity far in excess of what was reasonably required by load growth. Through this period,

estimated avoided cost at roughly half that amount.[31] In Maine, the rate was set at 9 to 10 cents/kWh based on the total all-in cost of the Seabrook nuclear generating station.[32]

- Many states did not readjust avoided cost rates as more QF capacity was added to the market. As QF capacity increased, the avoided cost (and the market price of electricity if it were known) should have gone down as the QFs displaced progressively cheaper capacity and energy. Many states failed to make this adjustment; however, with some establishing unvarying, above-market "standard offer" prices that QFs could receive without an avoided cost proceeding. This led to an oversupply of QF capacity in several states (California[33] and New York most notably), with long-term contract prices that were well above market.[34]

- Finally, many QF contracts were based on administratively-determined avoided costs using very high oil and natural gas price forecasts from the early to mid 1980s. Figure 16 shows the dangers of this approach. By the late 1980s and early 1990s, actual oil and gas prices had declined and were about 60 to 80 percent below the expected forecast levels from five to seven years earlier. Most long-term QF contracts, however, lacked any sort of adjustment clause to move the contract prices more in line with actual market conditions.

The overall effect of these mistakes was to burden electric utilities and their customers with a huge overhang of mandatory long-term contracts established at prices well above their actual avoided cost or any reasonable proxy of market prices. This burden was particularly concentrated in a number of states that set high, long-term, fixed PURPA prices without

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the PSC's forecast of LRACs failed to take into account the effect this excess supply would have on price until it was too late. When wholesale electricity prices fell dramatically in the 1990s, utilities and their customers were then saddled with onerous above-market long-term commodity contract costs. In addition, these contracts were structured as "must-take" agreements resulting in substantial uneconomic dispatch of New York generating plants, further exacerbating the collapse in wholesale electricity prices. The six-cent law was partially repealed in 1992, but many of the contracts already in place were grandfathered, preserving the six-cent minimum.

[31] Frank Graves, Philip Hanser, and Greg Basheda, The Brattle Group, "PURPA: Making the Sequel Better than the Original," prepared for the Edison Electric Institute, December 2006, 15-16.

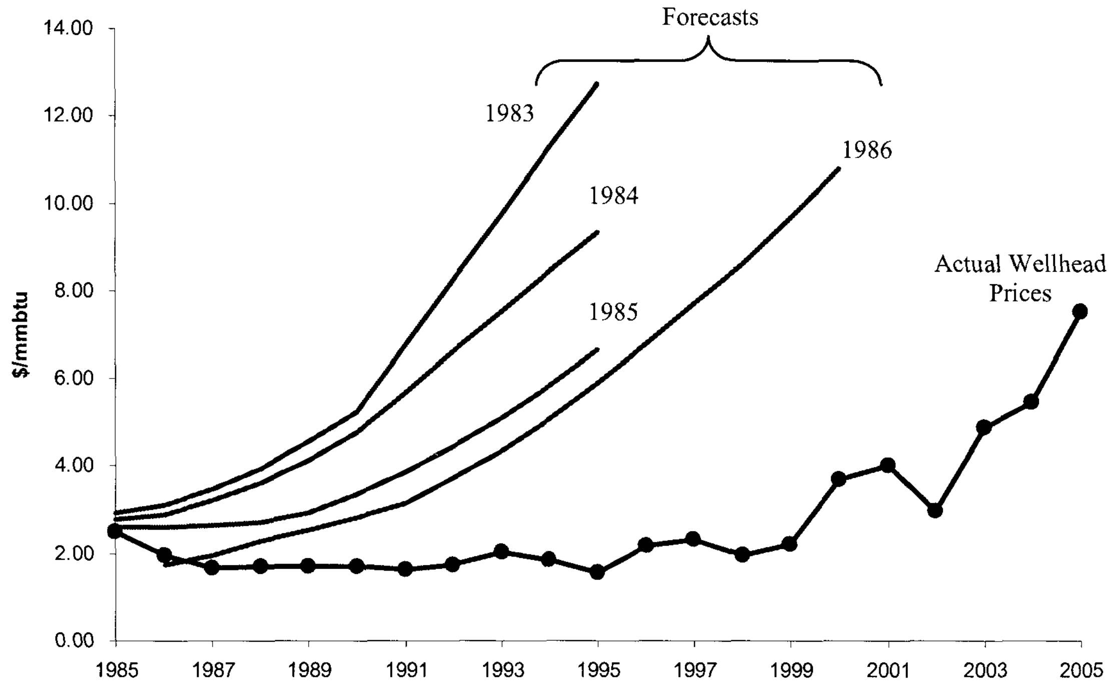
[32] Carroll Lee and Richard Hill, "Evolution of Maine's Electric Utility Industry, 1975-1995," *Maine Policy Review*, Vol. 4, No. 2 (1995): 22.

[33] Like New York, following the passage of PURPA, the California Public Utilities Commission interpreted the utility's obligation to purchase non-utility generation administratively. California utilities were required to purchase power at the utilities' long run marginal costs based on the expected cost of oil. At the time, oil was very expensive and expected to increase further in the future so the purchase price from QFs was set very high. California utilities were required to contract for all of the power offered at the state-determined price during an extended period. Unexpectedly, QF cogenerators were able to rely on low natural gas prices that were well below the oil price used to set the QF contract price. As a result, California utilities committed to contract for several thousand MW of QF electricity at high prices before the offer was terminated.

[34] Graves, Hanser, and Basheda, 16-17.

regard to the impacts of this QF supply on the price.[35] Overall, the cost to consumers from the mid-1990s onward was estimated at almost $50 billion in 2007 dollars.[36]

**Figure 16 Actual Natural Gas Prices Fell Below Forecasts of the Mid-1980s**




Source: Forecasts – Energy Information Administration, *Annual Energy Outlook*, Various Editions; Actual wellhead prices from Energy Information Administration, *Annual Energy Review*, 2005.

Problems similar to those experienced with the PURPA contracts have recurred in other later situations where regulators mandated long-term contracts. Most recently this happened in 2001 when the California Department of Water Resources stepped in to buy power under long-term contracts in the midst of the California energy crisis. Just a year later, the California Public Utilities Commission estimated that these contracts had burdened customers with approximately $21 billion in above-market costs and filed a (largely unsuccessful) complaint with FERC to allow the state to abrogate the contracts and to replace the contracts with lower-priced power at prevailing market prices.[37]

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[35] By the time restructuring was being contemplated in the second half of the 1990s, the difference between PURPA contract prices and competitive market prices was estimated to be a major contributor to regulated utilities' stranded costs - roughly 30 percent nationwide and as much as 70 percent in certain regions such as New York and California.

[36] Resource Data International, *Power Markets in the U.S.*, Boulder, CO, 1996.

[37] California Public Utilities Commission (CPUC), "PUC to Make Complaint to FERC Against Sellers of Long-Term Contracts," CPUC Press Release, 24 February 2002.

### C. Key Lessons of the Past Should Not Be Forgotten

Reviewing this past experience in the electric utility industry reveals several lessons on the shortcomings of regulation:

1. First and foremost, future electricity costs and prices are inherently uncertain. Because future load levels and fuel prices are unknown – as are changes in technology and environmental requirements – investments in long-lived generation assets are inherently risky. We can centrally plan these decisions, and impose the risks on retail customers, but we should not be surprised when things turn out badly for customers, particularly when we evaluate projects over 30 year time horizons and the risks are not borne by investors.

2. Decision-making under regulation performs particularly poorly in times of uncertainty. As the prior discussion makes clear, many of the difficulties in the electric industry arose from the fact that the administrative, command-and-control approach to resource allocation under regulation was too inflexible and too slow to respond to external stresses and changing market conditions.

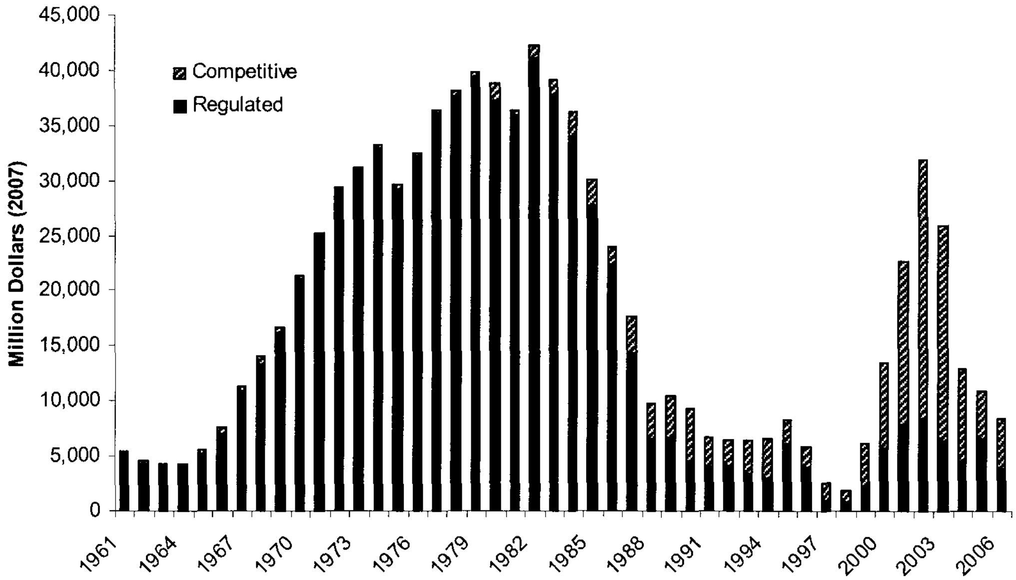
3. Inherent incentive problems with regulation create a tendency to take into account sunk costs when making decisions and to significantly underestimate the risks associated with high-capital cost investments. Much of the excess of planned baseload capacity at the start of the 1970s energy crises and the failure to trim that excess sufficiently in response to changing conditions can be attributed to improper incentives for regulated utilities.

4. Political and regulatory "solutions" to perceived problems can produce costly and unintended consequences. While PIFUA and PURPA may have seemed like reasonable responses to the headline problems of the time, their failure to incorporate market elements led to costly, inefficient responses that took years to correct.

Some might suggest that we can create a new, better form of regulation that would not repeat such mistakes. But the problems with regulation are inherent: decisions are administratively-determined versus market-driven, and the dollars at risk are highest and the potential for damage greatest during times of high capital investment. The mistakes of the 1970s were amplified by the sheer scale of the investment that utilities put at risk through baseload investments.

Figure 17 shows real investment in electric generation capacity in dollar terms since 1961. From 1970 to 1988 regulated utilities invested an average of $30 billion dollars per year in generation, compared to an average of $5 billion per year from 1989 to 2006. Over the past twenty years, because of the capacity overhang from the 1970s, there has been relatively little generation investment activity in the electric industry, particularly by regulated utilities. Thus, the opportunity for regulatory mistakes has been much lower. But, as discussed earlier, a new wave of investment is coming.

**Figure 17 Real Investment in Electric Generation Capacity, 1961-2006**




Source: Edison Electric Institute, Historical Statistics of the Electric Utility Industry Through 1992; NorthBridge analysis.

Some industry observers have advanced the notion that the coal and nuclear plants of today, with capital costs largely paid off and collected from customers, represent beneficial low-cost generation that is badly needed in today's rising-cost environment and that policy-makers should be glad that these plants were built. While it is true that coal and especially nuclear plants that were built in the 1970s and 1980s represent low-cost generation today, this is only because the high capital cost of those plants was borne by customers over the thirty-odd years since they were put into service. Measured over their entire life-cycle, many of these plants represented a bad investment for ratepayers and resulted in substantial excess capacity in the 1970s and 1980s and billions of dollars in higher costs relative to alternative supply strategies.

## IV. The Case for Competition is Still Compelling

The case for competition is still compelling, supported by both economic theory and a careful examination of empirical evidence. While the restructuring of the electric industry has proven to be a lengthier and more difficult process than anticipated, many of the recent arguments criticizing competition do not warrant returning back to regulation. Competition and market pricing encourages: (1) greater improvements in existing plant operations and administration, (2) greater efficiencies in plant investment and retirement decisions, (3) better customer consumption decisions, and (4) a wider selection of retail products and services. This innovation throughout the electric industry value chain, spurred by competitive forces, is greater than that experienced under regulation. Many of these benefits have already been evidenced in the brief history of electric competition, and the additional benefits that will materialize over time are illustrated by the experience of other competitive industries.

### A. Many Criticisms of Competition Have Emerged Recently

Today, electricity competition is under attack in the press and in many state legislatures and regulatory commissions. Since the beginning of the restructuring process, the public has read newspaper headlines about the California energy crisis, the Enron scandal, skyrocketing fuel prices, competitive generating company bankruptcies, and competitive generating company excess profits. Numerous studies, articles and reports have criticized competition or various aspects of restructuring. These complaints can be categorized into four broad concerns – high prices, high profits, poor resource planning, and limited customer switching to competitive suppliers.

First, opponents claim that competition has led to high prices – either high rate levels and/or high percentage rate increases – in restructured states relative to those experienced in regulated states.[38] Large rate shocks recently experienced in many states (e.g., Maryland, Delaware, Connecticut, and Illinois) are used as evidence to question the merits of competition.[39] While opponents acknowledge the recent increases in fuel costs, they argue that markets are not workably competitive[40] and competition has imposed new administrative

[38] Based on a comparison of percentage rate changes in industrial prices in restructured and regulated states, Jay Apt finds no improvement in prices in restructured states. (Jay Apt, "Competition Has Not Lowered U.S. Industrial Electricity Prices," Electricity Journal, Vol. 18, No. 2, (2005), 52). On the other hand, Mark Fagan developed an econometric model of industrial prices in 1970-1997 by state that he used to predict prices in 2001-2003. From his analysis, he concludes that predicted prices were higher than actual in restructuring states relative to states without restructuring, suggesting that restructuring has lowered prices. (Mark Fagan, "Measuring and Explaining Electricity Price Changes in Restructured States," Kennedy School Working Paper, No. RPP-2006-02, June 2006.)

[39] Paul Davidson, "Shocking Electricity Prices Follow Deregulation," *USA Today*, 10 August 2007.

[40] Synapse Energy Economics in a study prepared for the American Public Power Association ("APPA") states that the LMP approach to electricity pricing generally supports the efficient operation of existing resources, if the LMP pricing reflects short run marginal costs, but because electricity markets are bid-based, not cost-based and markets are not perfectly competitive, implementation of LMP is compromised and opens the door for the exercise of market power under certain conditions. (Ezra Hausman, et. al, Synapse Energy Economics, Inc., "LMP Electricity Markets: Market Operations, Market Power, and Value for Consumers," 5 February 2006, ix.) London Economics prepared a study that compared simulation-based estimates of prices that would result if all generators in PJM Classic were bidding their short-run marginal cost of producing electricity with actual market

and regulatory costs on customers, including high RTO costs,[41] capacity prices, congestion costs, and reliability payments.

Second, several studies claim that competition has led to high profits and profiteering, particularly for unregulated owners of baseload nuclear and coal generation that was built under prior regulation.[42] Opponents of restructuring argue that it has led to an enormous wealth transfer from retail customers, who paid for these assets, to unregulated utility affiliates, who now own this generation. The high profits of restructured utilities as compared to those that remain regulated are cited as evidence of market failure. Part of the concern stems from marginal cost pricing, which reflects the variable generating cost of the most expensive unit needed to meet load. Opponents argue that generator payments to baseload and mid-merit plants based on the higher marginal costs of peaking plants unjustly pays the operators of baseload and mid-merit plants more than their costs, allowing them to earn more than they would under cost-of-service regulation.[43] Some blame large capacity payments to owners of existing generation, while others raise issues of market price

clearing prices for a 43-month period, January 2003 through July 2006. The study reported that for most months studied the price-cost markup indices, especially for peak periods, are significantly higher than zero and that further study and analysis is necessary before conclusions can be drawn about the efficacy of the market system in PJM. (Julia Frayer, Amr Ibrahim, Serkan Bahceci, and Sanela Pecenkovi, London Economics International LLC, "A Comparative Analysis of Actual Locational Marginal Prices in the PJM Market and Estimated Short-Run Marginal Costs: 2003-2006," 31 January 2007.) In a paper prepared by John Taber, Duane Chapman, and Timothy Mount, the authors developed an econometric model of total average rates as well as residential, commercial, and industrial rates, by utility, for the period 1990-2003, controlling for differences in climate, fuel costs, and electricity generation by energy source. Their analysis does not support a conclusion that deregulation has led to lower electricity rates. They find that even though most customers in deregulated states saw declines in the real price of electricity, they faced higher prices relative to customers in still-regulated states. (John Taber, Duane Chapman, and Timothy Mount, "Examining the Effects of Deregulation on Retail Electricity Prices," Cornell University Working Paper, February 2006, 45.)

[41] A GDS Associates report examines the operational and administrative costs incurred by the nation's RTOs for 2001 through 2005. It finds that in 2005, RTO participants paid over $1 billion in total costs, most of which (75 percent) consists of administrative costs with the remainder (25 percent) operational. As RTOs mature, these costs on a per MWH basis tend to decrease, but as RTOs expand their services, costs tend to increase. (GDS Associates Inc., "Analysis of Operational and Administrative Cost of RTOs," prepared for the American Public Power Association, 5 February 2007, 28.) John Kwoka reports that many of the studies he reviewed fail to address the rising costs of RTOs, inadequate RTO governance processes, and the failure of RTOs to deal with transmission congestion or encourage new investment in transmission. (John Kwoka, "Restructuring the U.S. Electric Power Sector: A Review of Recent Studies," prepared for the American Public Power Association, November 2006, vii.)

[42] Edward Bodmer performed a study in February 2007 for the APPA, "The Electric HoneyPot: The Profitability of Deregulated Electric Generation Companies," that concludes that profits for deregulated generation are far higher than they would be if the plants were still under cost-based regulation. His analysis reviews the profitability of the largest sellers of unregulated generation in the PJM market and compares their financial performance with that of regulated, vertically owned utility companies. He observes that companies that fared the best tend to be owners of baseload generating assets that were formerly regulated. The APPA claims that certain sellers into RTO-run centralized markets are leveraging baseload generation built under prior regulation and are making very substantial profits and that incumbent sellers in PJM are making profits well-above what they would make under cost-of-service pricing. (Comments of the APPA, FERC docket RM07-19-000 and AD07-7-000, September 2007, 27)

[43] Baseload plants tend to be cheaper to operate but more expensive to build, while peaking plants tend to be more expensive to operate and less-expensive to build. Mid-merit or intermediate plants are in between.

manipulation and the potential exercise of market power, concluding that RTO prices appear "unjust and unreasonable."[44]

Third, there is considerable concern within the industry that competitive wholesale markets are not encouraging enough new investment in generation.[45] Parties cite projected declines in reserve margins in restructured regions of the country as compared to reserve margins in regions that remain regulated. Some opponents believe that only regulation and cost-of-service rate-making will ensure reliability, and others suggest that utilities be allowed or required to enter into long-term contracts, backed by regulatory guarantees, to promote the development of new generation. Other opponents lament the separation of generation and transmission functions and the loss of benefits associated with vertical integration.[46]

Finally, in most states (with the exception of Texas), there is the complaint that competition has resulted in little customer switching, especially among residential and small commercial customers. This lack of retail shopping is used as evidence for the failure of restructuring.[47]

In evaluating these arguments, it is important to recognize that many recent studies focus on the past ten or so years of restructuring experience, several of which are cited throughout this paper. But as described earlier, many of the challenges experienced in the industry today are more similar to those of the 1970s than those of the past ten years.

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[44] See Comments of the APPA, FERC docket RM07-19-000 and AD07-7-000, September 2007, 18. Kenneth Rose also prepared a study for the APPA, "The Impact of Fuel Costs on Electric Power Prices," (June 2007) that concludes while fuel price increases have played a role in higher electricity prices, they do not explain everything. He points out that while electricity price and natural gas costs often moved together, other factors are also important (e.g., customer load and its seasonal variation, and supplier costs and risks embedded in full requirements service retail rates). Mr. Rose raises the possibility that "strategic actions by suppliers" or "market design and structure" may also explain price changes in wholesale markets. In another study for the APPA, John Kwoka reports that studies generally do not consider that restructuring has been accompanied by market power, market manipulation, and numerous mergers among utilities. They also ignore costs of the loss of vertical integration and risk of market power abuses. (Kwoka, 73-75.)

[45] Timothy Mount prepared a study for the APPA that reviews NERC capacity margin forecasts 2003-2006 by region. He concludes all deregulated regions are having trouble getting investors to commit to building new generating capacity when it is needed. He notes that resources in deregulated regions are not being committed as far in advance as they used to be under traditional regulation, and the current performance of deregulated markets is poor in terms of ensuring that there is enough installed capacity to meet projected loads reliably. Meanwhile, substantial payments have been made to existing generators that supplement their earnings in the wholesale market. (Timothy Mount, "Investment Performance in Deregulated Markets for Electricity: A Case Study of New York State," September 2007, 1-10.)

[46] Jerry Taylor and Peter Van Doren of the Cato Institute argue that unfortunately, price deregulation has been accompanied by rules encouraging the legal separation of generation from transmission and the purchase of wholesale power through organized spot markets. Vertical integration of generation and transmission is efficient – since an integrated owner would not "hold-up" new investments, would consider substitution effects, and provide for more coordinated real-time operation. (Jerry Taylor and Peter Van Doren, "Short-Circuited," *Wall Street Journal*, 30 August 2007.)

[47] Davidson, "Shocking Electricity Prices Follow Deregulation."

## B. Historical Rate Comparisons to Date Are of Little Value

Authors of the competition versus regulation studies, as well as critics, acknowledge a variety of difficulties with attempting to compare regulated and competitive markets.[48] Many of the recent studies focus on historical rate comparisons – both before and after restructuring in the same state, and across regulated and restructured states. Presumably, the purpose of such rate comparisons is to determine whether competition has produced higher or lower rates than would have existed under regulation. However, it is difficult, if not impossible, to know what rates would have been in the absence of competition, making a fair rate comparison problematic.[49]

To further complicate state comparisons of restructuring and regulation, restructuring is not well-defined. In fact, many studies often do not agree on whether a particular state should be included in the "restructured" or "regulated" category. Unlike restructuring in other industries, which often occurred as a result of changes in federal legislation, restructuring in the electric industry occurred in a more decentralized manner. Key elements of the restructuring process include: a) providing utilities and non-utilities open-access transmission service, b) splitting up vertically integrated utilities by separating control of transmission and generation assets, c) the formation of ISOs and RTOs and centralized wholesale electricity markets, d) developing stranded cost recovery mechanisms for past utility investments and past contracts that regulators approved/required during regulation, e) establishing transition periods and default service pricing to move from a regulated to a competitive market structure, and f) allowing retail access programs (including customer switching, customer protection, deposit and disconnect rules, and systems for processing retail market transactions). These changes both in wholesale and retail electricity markets have occurred in stages that vary in form over time and often by U.S. region, state, service area, and even customer type. And in several instances, there has been considerable conflict between federal and state authorities over legal jurisdiction over market structure design. The lack of consistent policies, along with fundamental changes in economic conditions since the advent of restructuring, has made it difficult to compare regulated and competitive market structures.

In addition, certain market initiatives integral to industry restructuring, such as open-access transmission and the expansion of competitive generation have also benefited regulated states, even though those states do not have retail choice. For example, almost 72 GW of unregulated generation were constructed in regulated states between 1997 and 2007. This construction reduced both prices in these states and the need for regulated utilities to build rate-based plants, further complicating comparisons between regulated and restructured states.

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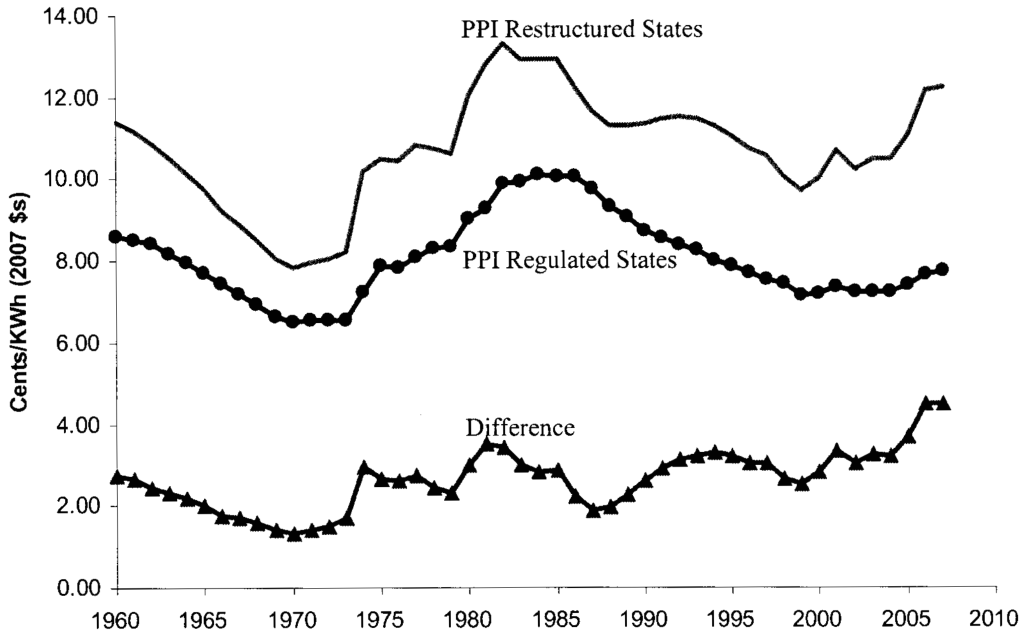
[48] Efforts to date attempting to compare regulated and competitive markets have proven difficult due to the lack of sufficient data and other fundamental complications with such an analysis. John Kwoka, in his review of restructuring studies, found three common problems with most studies: 1) lack of precision about what is meant by restructuring, 2) failure to recognize that post-reform prices were set administratively and do not reflect market levels, and 3) failure to control for other factors that affect prices unrelated to restructuring. (Kwoka, 7-24.)

[49] Several econometric studies have attempted to control for some of the variables and changes that have occurred since restructuring. However, the results of these studies are mixed. See citations within these footnotes.

Most studies, however, attempt to compare regulated and restructured states, and acknowledge that rates in states that have restructured have been higher than rates in regulated states for a long time, and that this price gap predates restructuring and the introduction of competition. Figure 18 compares historical average real rates for states that have restructured with states that have remained regulated based upon the state characterization utilized in a recent analysis by Power in the Public Interest (hereafter referred to as "PPI Restructured States" and "PPI Regulated States").[50]

**Figure 18 Real Retail Electric Rates in PPI Restructured and PPI Regulated States, 1960-2007**




Source: Edison Electric Institute, Historical Statistics of the Electric Utility Industry Through 1992; Energy Information Administration State-Level Spreadsheets, 1990-2006; 2007 rates are from December 2007 Energy Information Administration Electric Power Monthly; Average rates are weighted by consumption in each state.

The significant rate gap between states that restructured and those that remain regulated is due to regional differences in a wide variety of factors: fuel and construction costs, state regulatory policies, generation mix, customer types, consumption patterns, population density, and supply and demand balances.[51] The gap between the two groups actually closed as competition was introduced in the late 1990s – primarily due to rate cuts embedded in the

[50] For purposes of this comparison only, we utilize the same definition of restructured states as a recent analysis by Marilyn Showalter of Power in the Public Interest, "Trends in State Electricity Prices and Policies" (*Presentation to MEAG*, 17 July, 2007.) This analysis defines CA, CT, DC, DE, MA, MD, ME, MI, NH, NJ, NY, RI, and TX as restructured/deregulated. While we disagree with certain elements of this categorization (particularly the inclusion of California and the exclusion of Illinois and Pennsylvania), we adopt this definition to allow for comparison of our results with other studies that take a critical view of competition.

[51] Local transmission monopolies facilitated the disparity in retail rates by restricting the ability to move electricity economically across service territory boundaries. When purchasing electricity, a buyer often had to pay the transmission rate to each utility that it moved through, commonly referred to as rate "pancaking." This limited the ability to move power from low-cost areas to more expensive areas.

restructuring deals and transition periods[52] – but has expanded since 2005. Once transition periods and rate controls began to expire in restructured states, market conditions were dramatically different than at the start of restructuring. Significant increases in fuel costs, unrelated to the restructuring of the electric industry, have caused wholesale market prices to increase significantly throughout the United States (see Figure 2 and Figure 4).[53] As a result, when rate caps expired at the end of restructuring transition periods, many consumers of electricity were exposed to sudden price increases. In several instances, these rate shocks resulted in legislative and/or regulatory intervention, which ultimately led to phase-ins of market rate increases and deferred cost recovery.

While acknowledging this long-running rate gap between regulated and restructured states, many opponents of competition focus on a snapshot comparison of rates as they are today in restructured states to the rates in effect in those same states in the late 1990s, prior to restructuring. This comparison misses several key points. First, rates in regulated states have also experienced significant rate increases over the same period.[54] Figure 19 shows the annual change in nominal rates for both PPI Regulated and PPI Restructured States indexed to 1997, just prior to restructuring in most states. By 2007, nominal rates in PPI Restructured States had increased by 44 percent relative to 1997, but had also increased by 28 percent in PPI Regulated States.

Second, most of the increase in rates in PPI Restructured States has occurred in the past three years. This lag in the rate of increase in restructured states was primarily due to rate freezes that were part-and-parcel of the restructuring process. These negotiated rate structures, which did not reflect market prices, prevented more gradual increases in rates like those experienced in regulated states or restructured states with market adjustable rates. The price increases in restructured states from 2005 onward can be primarily traced to the expiration of rate freezes[55] coinciding with an increase in marginal generation costs, largely due to the rise in natural gas prices. Had natural gas prices not increased dramatically, the rate comparisons between restructured and regulated states may have appeared substantially different. Figure 20 shows a similar comparison between PPI Restructured States and PPI Regulated States, but compares only states where natural gas either strongly influences the competitive market price in restructured states or forms a large portion of fuel costs in regulated states.

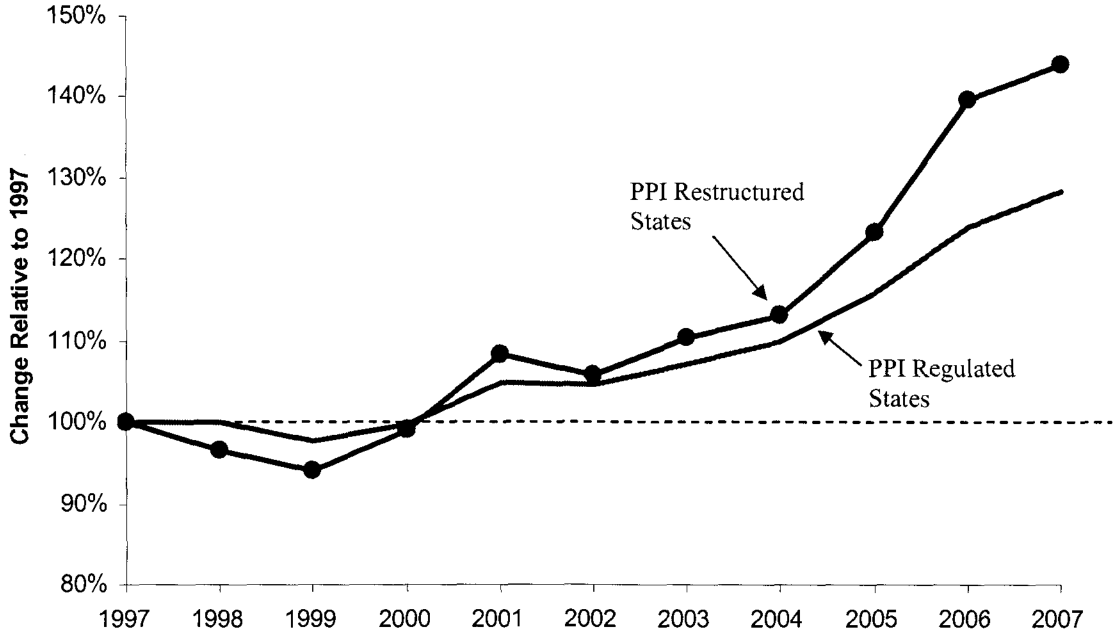
[52] Past restructuring deals included stranded cost determinations along with negotiated rate decreases and/or mandated rate freezes during prescribed transition periods.

[53] A Brattle Group report finds that, "On an industry-wide basis…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 costs of these fuels have been unprecedented by historical standards, affecting every major electric industry fuel source." (Greg Basheda et. al., The Brattle Group, "Why are Electricity Prices Increasing? An Industry-Wide Perspective," prepared for The Edison Foundation, June 2006, 2.)

[54] Studies performed both by The Brattle Group and the Analysis Group also find that regulated states have seen substantial increases in average annual retail prices similar to that observed in the restructured states. (Analysis Group, "Electricity and Underlying Fuel Prices - A Survey of Non-Restructured States," April 2006; Greg Basheda, Johannes Pfeifenberger, and Adam Schumacher, The Brattle Group, "Restructuring Revisited: What We Can Learn From Retail-Rate Increases In Restructured And Non-Restructured States," *Public Utilities Fortnightly*, June 2007, 64-69.)

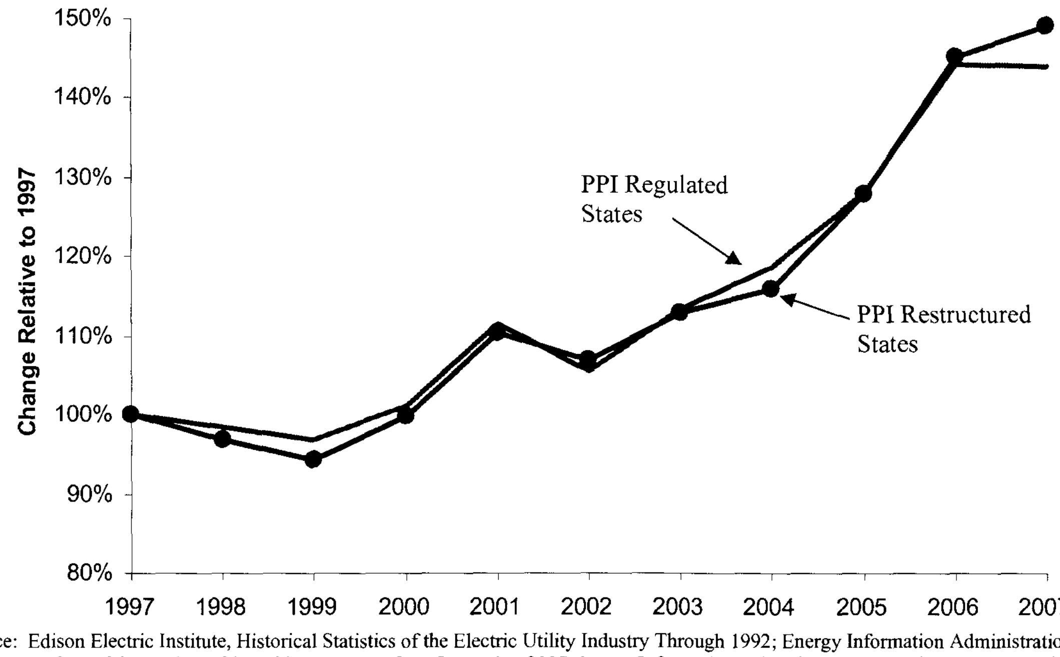
[55] Since 2005, several major restructured states such as Illinois, Massachusetts, Connecticut, and Maryland have transitioned from rate freezes to auction-based frameworks in which customers receive competitive wholesale market prices. Other states such as Texas and New Jersey had transitioned to a market price framework earlier.

**Figure 19 Rate of Change in Nominal Electric Rates in PPI Restructured and PPI Regulated States, 1997-2007**




Source: Edison Electric Institute, Historical Statistics of the Electric Utility Industry Through 1992; Energy Information Administration State-Level Spreadsheets, 1990-2006; 2007 rates are from December 2007 Energy Information Administration Electric Power Monthly; Average rates are weighted by consumption in each state.

**Figure 20 Rate of Change in Nominal Electric Rates in Gas-Dependent PPI Restructured and PPI Regulated States, 1997-2007**

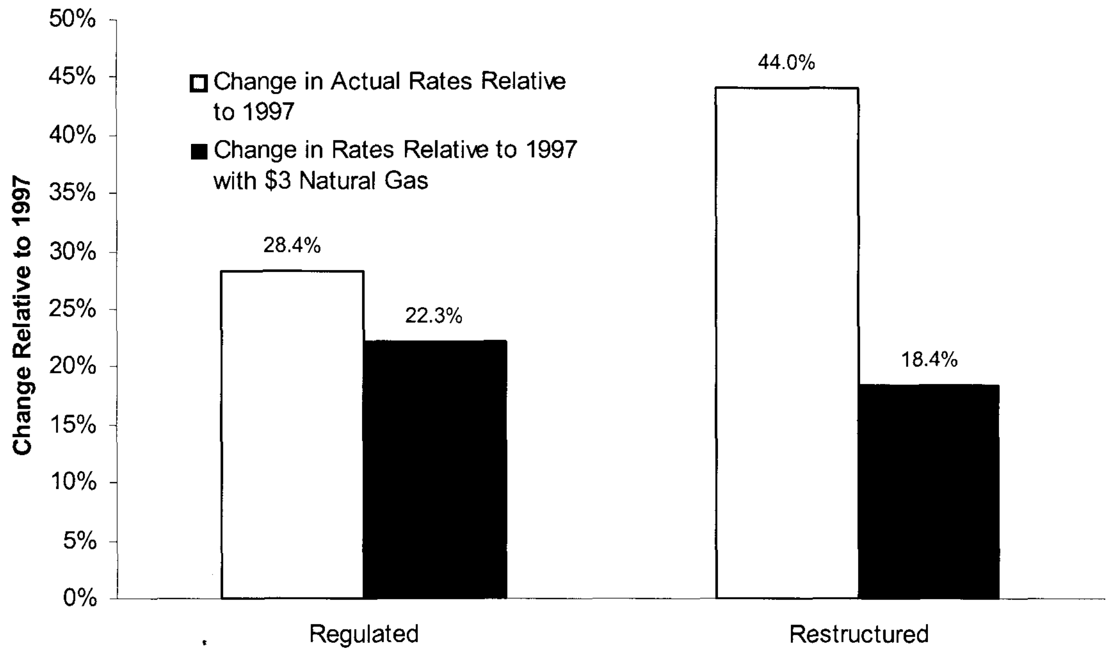



Source: Edison Electric Institute, Historical Statistics of the Electric Utility Industry Through 1992; Energy Information Administration State-Level Spreadsheets, 1990-2006; 2007 rates are from December 2007 Energy Information Administration Electric Power Monthly; Average rates are weighted by consumption in each state; Gas-dependent restructured states are from the ISO-New England, NY ISO, ERCOT, PJM East, and CA ISO market regions and include all PPI Restructured States except Michigan; Gas-dependent regulated states are defined as any regulated state where gas/oil generation comprises 30% or more of total generation output (FL, LA, NV, MS, and OK).

When compared in this manner, rate increases in both PPI Restructured and PPI Regulated States track one another very closely.

Figure 21 compares actual price changes over the 1997 to 2007 period to an estimate of what rates would have been had natural gas prices remained at $3/MMBTU, approximately their level in the late 1990s.

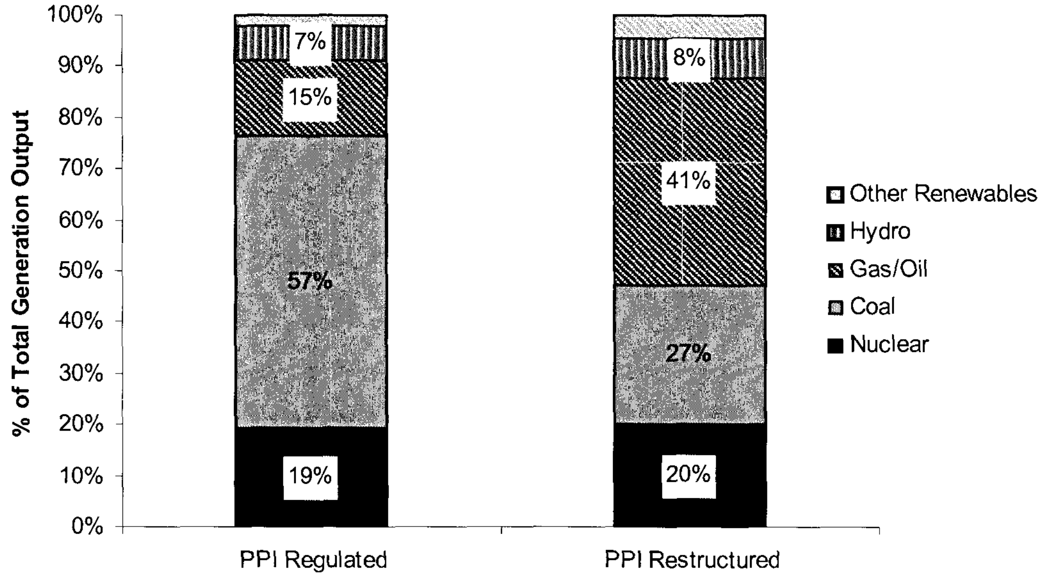
**Figure 21 Change in Nominal 2007 Rates Relative to 1997, Actual vs. If Natural Gas Remained at $3 Per MMBTU**




Source: Edison Electric Institute, Historical Statistics of the Electric Utility Industry Through 1992; Energy Information Administration State-Level Spreadsheets, 1990-2006; 2007 rates are from December 2007 Energy Information Administration Electric Power Monthly; Average rates are weighted by consumption in each state; NorthBridge Analysis.

Under this comparison, rates in PPI Restructured States would have only risen by 18 percent by 2007, relative to 1997, while rates in PPI Regulated States would have risen by 22 percent. These differences are primarily caused by the variation in fuel inputs used to produce electricity combined with differences in how electricity is priced to end-use customers in regulated and restructured states (as discussed later). Figure 22 compares the electric generation by fuel type in both PPI Regulated and PPI Restructured States.

**Figure 22 Electric Generation By Fuel Type: PPI Regulated vs. PPI Restructured States**




Source: Energy Information Administration, State-Level Spreadsheets, 1990-2006. Data shown is for 2006.

PPI Restructured States generate 41 percent of their electricity from natural gas, compared to 15 percent in PPI Regulated States.[56] This difference dates back at least to the 1980s and is not a product of restructuring or competition. Instead, it reflects decisions made by utilities and regulators in favor of cleaner gas generation relative to cheaper, but dirtier, coal.[57] As a result, PPI Regulated States, as a group, emit about 30 percent more $CO_2$ per MWH than do PPI Restructured States. The reliance on natural gas in restructured states has the effect, however, of amplifying the effect of changes in natural gas prices on rates in restructured states. Florida, a similarly gas-dependent regulated state, has experienced much larger rate increases – 26 percent – from 2004 to 2007. This is much larger than the average rate increase of 17 percent in other regulated states, but similar to the average rate increase of 27 percent in restructured states over the same period.

[56] "...some regions (like New England, California, and Texas) that rely significantly on natural gas to produce power have relatively high electricity prices...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..., 26 of them were from these regions with a high percentage of power produced by coal." (Susan Tierney, Analysis Group, "Decoding Developments in Today's Electric Industry – Ten Points in the Prism," commissioned by the Electric Power Supply Association, October 2007, 4.)

[57] While both natural gas and coal are fossil fuels, natural gas burns more cleanly than coal. Per megawatt-hour of power produced, relative to a typical coal plant, a natural gas combined cycle plant will emit about 40% of the $CO_2$, 5-50% of the acid-rain causing nitrogen oxides (depending on the level of control at the comparison coal plant), and essentially zero sulfur, mercury, and particulate matter.

## C. Market Prices Provide the Right Price Signals

Retail rates in most restructured states are now based on competitive wholesale prices. In a competitive wholesale market, the variable generating cost of the most expensive generating unit needed to meet load sets the wholesale price for all generation in the market.[58] The price is determined by the market: all transactions between sellers and buyers tend toward one price for the same product (electricity at a given time and location), taking into account available supply and demand. The price obeys what is referred to in economics as the "law of one price."[59] This is commonly referred to as "marginal cost" pricing. The price-setting marginal unit will be a higher-cost unit, such as a gas/oil unit or older coal plant. Therefore, the price for the entire market will be based on the higher variable costs of these types of units, regardless of whether coal or nuclear units with lower variable costs are also online and generating electricity.

Regulated retail rates, however, have traditionally been determined using "average cost" pricing. Under this approach, the total cost of the portfolio of resources needed to serve load, from baseload plants to peaking units, is averaged across total load, and this average price is charged to each increment of load. This total cost includes both variable operating costs as well as the historical embedded capital costs of building and financing generation. These two types of pricing differ most significantly in how generators recover their capital and fixed operating costs: in market-based marginal cost pricing all fixed cost recovery flows through the market price (although recovery is not guaranteed), while in average cost pricing generators are allowed to pass through their variable costs and recover their capital and fixed operating costs through regulated base rates. All else equal (ignoring any demand-side effects), we would expect both marginal cost pricing and average cost pricing to yield a similar average price over long time periods. However, there are two important differences. First, in the presence of uncertainty and rising/falling costs, the two types of pricing will usually differ at any particular "snapshot" in time. Second, because market-based marginal cost pricing reflects the variable generating cost of the most expensive unit needed to meet

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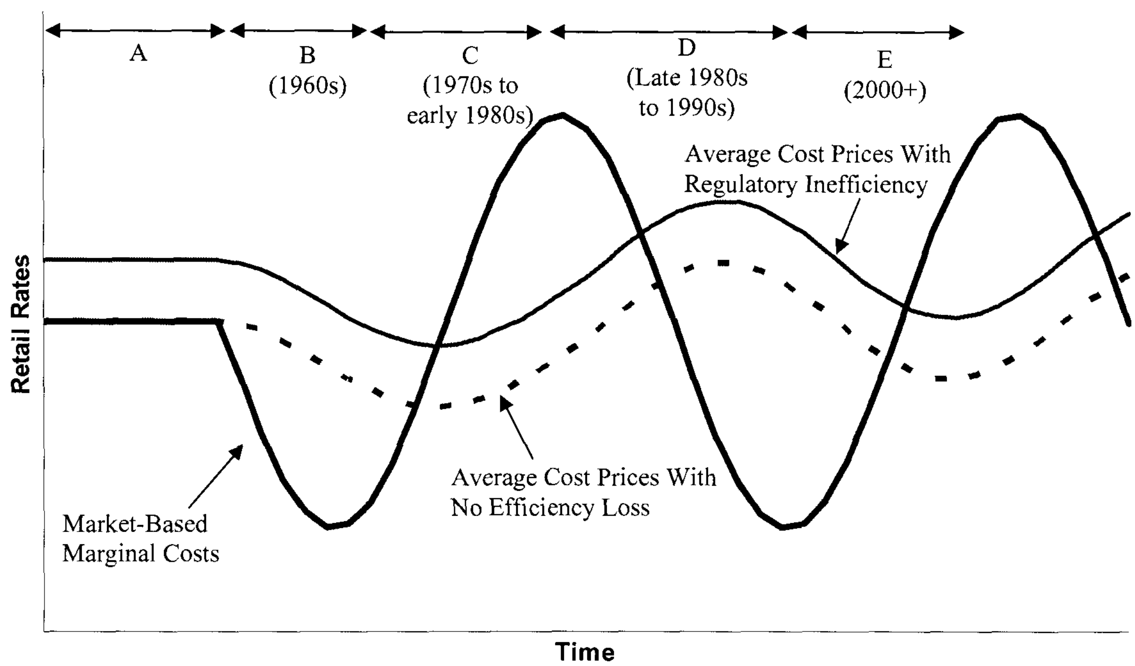
[58] In a pool trading system, an auctioneer can see all the bids and can choose between two broad payment schemes. The auctioneer can pay dispatched generators what they bid – this is similar to the bilateral trading model described in the footnote below. Alternatively, the auctioneer can pay dispatched generators a uniform market price based on the marginal cost of the highest cost generator operating. In theory, neither the market structure nor the payment scheme should make any difference for the level of wholesale prices. In a bidding system where generators are all paid the same market clearing price – like in the United Kingdom and most U.S. energy markets – the generator bidding strategy changes but the resulting market price does not. As before, no generator would rationally bid a price below its marginal cost. However, rather than bid the estimated market clearing price, each generator will have an incentive to bid its actual marginal costs. Economist William Vickrey (1961) noted that by making the price received by a player independent of its own bid, marginal cost pricing can be induced as a dominant bidding strategy for all participants. This system is perhaps more efficient since it encourages generators to reveal their true marginal costs rather than attempt to estimate the market price – although the price outcome is essentially the same in markets with good information flows.

[59] Bilateral transactions allow buyers and sellers to propose prices and indicate desired quantities with different payments. However, with good information available and many buyers and sellers, i.e. a liquid market, traders are aware of each other's price quotations, and they come to have nearly identical opinions of the prevailing market price at any moment. For a buyer to quote too far below "the price", or for a seller to quote too far above it, is essentially to withdraw from the market, and there is no reason to expect such extreme quotations to be accepted. Commodity exchanges organize this type of trading at a single point in time on a trading floor. The outcome of this competitive trading process is that all buyers and sellers are price takers, not price makers.

load, it provides a superior price signal (as described further below) for dispatch of existing resources, new entry of generation, innovation, and customer demand response than does average cost pricing. Market-based marginal cost pricing will ultimately lead to a more efficient allocation of resources than would average cost pricing, and will result in lower average prices over the long-term.

These two differences are best illustrated through an example. Figure 23 shows an illustrative example of the behavior of market-based marginal cost and average cost rates through a progression of changing cost environments over time, with a relative abundance or shortage of generation resources.

**Figure 23 Comparison of Marginal Cost vs. Average Cost Rates**




Because marginal costs represent the incremental cost of serving the final unit of demand while average cost rates represent the historical embedded cost of serving every unit of demand, market-based marginal costs rates are much more sensitive to changes in input costs (such as fuel and capital costs) and the marginal supply/demand balance of generation and load. For average cost rates, however, historical embedded costs tend to dominate and changes in marginal unit economics represent only a small portion of the average. This difference causes average cost rates to lag behind market-based rates as electric input costs change and the supply/demand balance fluctuates. Segment A shows an initial period of unchanging costs: all else equal, market-based marginal cost rates and average cost rates will be the same. As marginal costs fall (over segment B), market-based rates will fall faster than average cost rates because average cost rates contain the higher embedded costs from segment A. When marginal costs start rising (segment C) average cost rates will lag behind market-based rates in reflecting these rising costs in prices. Eventually, however, this will lead to average cost rates overshooting market-based rates when costs start falling again (segment D). This pattern is what occurred as we moved from the 1960s (falling costs) to the 1970s and early 1980s (rising costs), to the late 1980s and 1990s (falling costs again). Indeed, much of the impetus for restructuring in the late 1990s centered on the observation that average generation costs (reflected in retail rates) substantially exceeded marginal generation costs (as observed in wholesale market prices), just as the illustration predicts. Since 2000, however, costs have begun to rise again and we are now on segment E of the curve. Recent changes in retail electricity rates confirm this, as rates based on wholesale electricity prices (such as those produced by wholesale auctions or competitive retail offers) have risen quickly over the past three years, while rates in regulated states have lagged behind.[60]

As the illustration makes clear, a "snapshot" comparison of current rates does not imply that market-based, marginal cost rates are inherently higher than regulated average cost rates. The appropriate comparison is over the longer-term, which allows a more complete evaluation of a full cycle of changing cost environments. In the end, the historical rate evidence to date is of little value to the ongoing debate on competition; it does not definitely prove that competition has reduced rates over the last ten years, nor does it conclusively show that competition has increased rates. Furthermore, a definitive answer to this question may not help us solve the challenges ahead. If we accept that rates in competitive states were lower than they would have been if those states had remained regulated through 2005, but, because of high natural gas prices, are now higher than they would be if those states had remained regulated, would this mean that the industry should return to regulation? We believe the answer to this question is "no." The decision to support competition or regulation should not depend on external shocks (such as the recent increase in natural gas prices) or whether regulated average cost prices are below or above market-based marginal cost prices at any particular point in time, but whether a competitive or regulated model will foster more efficient decisions and ultimately better price and reliability outcomes over a sustained period of time and varying market conditions.[61]

Thus far, given the large oversupply of capacity built during the regulated period of the 1970s and 1980s and the recent unregulated generation development of the early 2000s, there has been relatively little need for significant regulated generation investment since the start of restructuring. As we have already discussed, the electricity market in the next twenty years will look very different than it has in the past ten years. Therefore, the recent historical "test period" of the past ten years examined in most studies does not provide a complete picture – especially of what is to come as we confront the significant challenges ahead.

Over longer time cycles, marginal cost pricing will produce a more efficient and ultimately lower-cost outcome relative to regulated average cost prices because it provides the correct

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[60] Jerry Taylor and Peter Van Doren of the Cato Institute acknowledge that regulation delivers lower prices than the market during shortages, but regulation delivers higher prices during times of relative abundance. (Taylor and Van Doren, "Short-Circuited.")

[61] At the time of restructuring, utility retail rates based on regulated average costs were much higher than competitive marginal cost prices in the wholesale market. Buyers, especially large customers, wanted direct access to these lower wholesale prices. This large gap between high utility retail rates and low wholesale market prices provided much of the impetus for restructuring. Today, the situation has reversed. Marginal prices have risen above average cost rates in many places. Hence, there is increasing pressure to look back more fondly upon regulation.

price signal for the efficient allocation of new and existing generation and demand response resources. Market-based, marginal cost prices provide the correct entry signal for new resources, whether in real time (such as committing a peaking unit) or over a longer time horizon (such as building new capacity or developing demand response resources).[62] As noted earlier, the rising costs observed over the past few years are unlikely to disappear soon, and will become even more pronounced in a carbon-constrained world. High market prices in the context of today and the near future are appropriate in that they provide the correct price signal and incentive for investment in the different types of low-carbon resources that will be needed in the future.

In an effort to limit "high" profits, some critics of competition argue that today's low cost generators (e.g., nuclear and coal plant owners) should not be paid the price associated with the higher marginal cost unit (e.g., a gas plant), but rather should be paid according to their individual (and much lower) variable costs of production. This logic represents a key misunderstanding about how competitive markets function. As Figure 23 suggests, in the presence of market volatility, prices and ultimately profits for all types of units will fluctuate, often significantly, in a competitive electricity market with marginal cost pricing. "High" profits in one period provide the necessary incentive for market entry and an eventual reduction of those profits through increased supply and competition. High market prices do not necessarily imply market manipulation or the exercise of market power.

Allowing the market to determine the price, of course, should rest upon the existence of a "workably" competitive market. Clearly, developing competitive markets are not perfect, and legitimate concerns exist that require safeguards and regulatory oversight (see discussion in Section V.B.). Examples of inappropriate generator bidding behavior, price manipulation, and poor market design have been uncovered during the transition period. Just as the industry experienced unanticipated consequences from past legislation and regulatory policies, it should not be surprising that new restructuring initiatives and market designs do not always work as anticipated. However, these are reasons to improve markets, not abandon them. There are several key reasons why policymakers should support the continued development of competitive markets, as discussed in the remainder of this section.

### D. Competition Promotes Efficiency Improvements in Existing Plant Operations and Administration, in Plant Investment and Retirement, and Customer Consumption

Market-based marginal cost price signals, while not always lower than regulated average cost rates, provide a superior price signal to power plant operators, investors in new generation and new supply and demand side technologies, and consumers of electricity. In the short term,[63] competitive markets provide strong incentives to improve plant performance and

[62] The incremental cost of serving the final increment of load represents the true opportunity cost that new resources appropriately measure themselves against: if market prices rise to a level where they allow new capacity to cover its operating and capital costs, then that capacity will have an incentive to enter, if market prices remain below this level the market will utilize cheaper existing resources.

[63] In economics, "short-term" generally refers to the period of time over which the quantity of some inputs (e.g., such as existing plant capacity) cannot, as a practical matter, be varied, while the "long-term" refers to the period of time long enough for all inputs to be varied.

administration. Restructuring also has increased the geographic size of regional markets, extending the benefits of pooling and coordination across a broader market area. In the long term, competition provides efficiency gains in resource planning and investments, making investors, not ratepayers, responsible for a host of decisions (e.g., choice of technology, fuel, timing, pollution control, etc.) in an electricity market that is inherently risky. This shift in responsibility will allow customers to avoid having to pay for the stranded costs associated with investments or long-term contracts that later turn out to be uneconomic. Market price signals, when visible to customers, ultimately will lead to more efficient customer consumption and investment decisions both in the short and long term – impacting a customer's time of electricity use, overall level of electricity use, fuel choice, and investments in equipment and energy efficiency.

#### 1) Competition Promotes Efficiency in Existing Plant Operations and Administration

##### a) The Theory

Competitive markets provide strong incentives to improve plant performance and administration in the short term. This improvement is often called "static" efficiency, which refers to the benefits that can be realized within the existing fleet of generators. In a competitive wholesale market, generators sell their output by either bidding directly into the spot market or through bilateral contracts based on expected spot prices. As discussed earlier, in most competitive wholesale markets, the market-clearing bid of the marginal plant is paid to all plants that are dispatched. High-cost bidders will be less likely to be dispatched and less likely to earn revenue, while plant operators that reduce costs and are able to submit lower bids are more likely to get dispatched and increase their profit margin between their own costs and the market price. This competitive structure, as opposed to a regulated model that allows plant operators to pass through their operating costs to customers, provides a strong financial incentive to lower both variable and fixed operating costs, since each incremental dollar of cost reduction benefits the plant owner. Competition impacts decisions related to operating and maintenance budgeting, capital improvements, fuel procurement, environmental compliance, and so forth. When evaluating specific operational changes, a number of incremental performance measures (e.g., increased availability, heat rate reduction, increased maximum output, increased ramp rates, start-up cost reduction, reduced minimum generation levels, etc.) provide the critical link between market prices and decentralized decision-making. By weighing the relative costs and benefits of any decision, managers can implement actions that are economic based on market price signals.

##### b) Early Results – Improvements in Dispatch Efficiency, Plant Performance, and Fuel Efficiency

First, restructuring has improved the efficiency of power plant dispatch (i.e., how generators are turned on or off to meet customer demand). Efficient dispatch is a function of marginal operating costs subject to transmission and unit commitment constraints.[64] Restructuring has increased the geographic size of regional markets, extending the benefits of pooling and

[64] Neither sunk capital nor fixed operating costs, nor who paid for them, is relevant to dispatching existing generators efficiently.

coordination across a broader market area.[65] Non-discriminatory open transmission access combined with broad geographic energy markets improves economic dispatch and coordination within the industry, ultimately lowering overall system supply costs. Restructuring reduces the level of rate "pancaking" through each utility service area that allows parties to trade more easily within a broad geographic area. Numerous studies have quantified these benefits, and the magnitude of estimated savings far exceeds the incremental RTO administrative and operating costs.[66] A particularly striking example of increased dispatch efficiency in a competitive market is provided by the large shifts in plant dispatch and physical power flows that occurred when the PJM market expanded to incorporate the service areas of American Electric Power, Commonwealth Edison, and Dominion. In each case, capacity utilization of relatively cheap baseload capacity in the newly incorporated area rose, and power flows into the high-cost, congested area of Eastern PJM increased. This

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[65] The benefits of coordination have been recognized within the industry for many years. The reliance on relatively short-term coordination services among nearby integrated utilities developed in order to reduce system operating costs and the costs of maintaining reliability through reserve sharing and emergency support. This coordination expanded dramatically after 1973 due to the increase in oil prices as the gap between oil, gas and coal prices widened. Utilities began to rely on medium and longer term wholesale contracts to allow them to defer construction of new facilities when other utilities had excess capacity or to reduce operating and maintenance costs of higher cost generating facilities. This "sharing" of resources in the wholesale market provided benefits to both buyers with capacity shortfalls and/or high-cost generation and sellers with excess capacity and/or low-cost generation.

[66] Scott Harvey, Bruce McConehi, and Susan Pope of LECG prepared an econometric study of customer savings in PJM and the NY ISO as a result of implementing coordinated markets, comparing 1990-2004 average residential rates in PJM classic and NY ISO with those in traditional markets, namely SERC and Florida. They used data for munis and co-ops in order to isolate the effects of retail access. Regressions were used to isolate the effects of RTO participation, regional fuel mixes, utility size, sales per customer, and the portion of industrial load, and to derive the "would have been rates" in order to calculate savings in PJM and the NY ISO regions. Based on this analysis, they concluded that the implementation of coordinated markets has led to residential customer savings of $0.50 to $1.80 per megawatt-hour (or $430 million to $1.3 billion per year) in PJM and NY ISO. These savings are net of RTO costs. (LECG, "Analysis of the Impact of Coordinated Electricity Markets on Consumer Electricity Charges," November 2006, 1.) Polestar Communications and Strategic Alliance performed a calculation of customer savings in New England due to restructuring based on historical trends in prices. They examined average retail rate growth from 1990 to the year of restructuring to construct "would have been" rates and compared those to actual rates. They concluded that customers have saved $6.5-$7.6 billion in New England between 1998 and 2005, including the savings associated with rate cuts and freezes. (Polestar Communications and Strategic Analysis, "A Review of Electricity Industry Restructuring in New England," prepared for members of the New England Energy Alliance, September 2006, 4.) Cambridge Energy Research Associates developed econometric models of total average electric prices in 1981-1997 for four regions and predicted 1998-2004 prices. They found that predicted prices were above actual prices in 3 out of 4 regions, and concluded that U.S. residential electric customers paid about $34 billion less over a 7 year period than they would have under regulation. ("Beyond the Crossroads: The Future Direction of Power Industry Restructuring," 2005). Global Energy Decisions performed a simulation of expected market prices had deregulation not occurred in the Eastern Interconnect, 1999-2003. They concluded that wholesale customers in the region saved $15.1 billion as a result of deregulation, attributed to increased operating efficiencies at power plants (e.g., shorter refueling outages, better capacity factors and improved reliability). (Global Energy Decisions, "Putting Competitive Power Markets to the Test – The Benefits of Competition in America's Electric Grid: Cost Savings and Operating Efficiencies," July 2005, ES-1.) Charles River Associates performed an analysis of customer benefits in SPP from having coordinated dispatch and an energy imbalance service market, concluding that transmission owners would save $373 million between 2006 and 2015 as a result of the energy imbalance market, net of implementation costs, and transmission owners would save $71 million between 2006 and 2015 as a result of coordinated dispatch. (Ellen Wolf et al., "Southwest Power Pool: Cost-Benefit Analysis," performed for the SPP Regional State Committee, July 2005, Tables 1 and 4.)

indicates that previously unrealized opportunities for economic dispatch and wholesale power trade were unlocked by pooling resources within an expanded competitive market.[67]

Second, U.S. generating plants are now more efficient than in the past. Some of this improvement in performance is attributable to improvements in technology over time, but some of it also is due to powerful profit incentives to adopt best practices and invest in productivity gains in an economic manner. A recent study of all large steam and combined cycle gas turbine plants in the United States suggests that municipally-owned plants, whose owners were largely insulated from market reforms, experienced the smallest efficiency gains, while investor-owned plants in states that restructured their wholesale electricity markets have improved efficiency the most. Investor-owned plants in states that did not restructure were in between these extremes. Industry restructuring reduced labor costs by 6 percent and non-fuel costs by 12 percent, holding output constant, relative to government and municipal-owned plants.[68] In general, studies suggest that restructuring has led to substantive operating efficiency gains in a relatively short period of time.

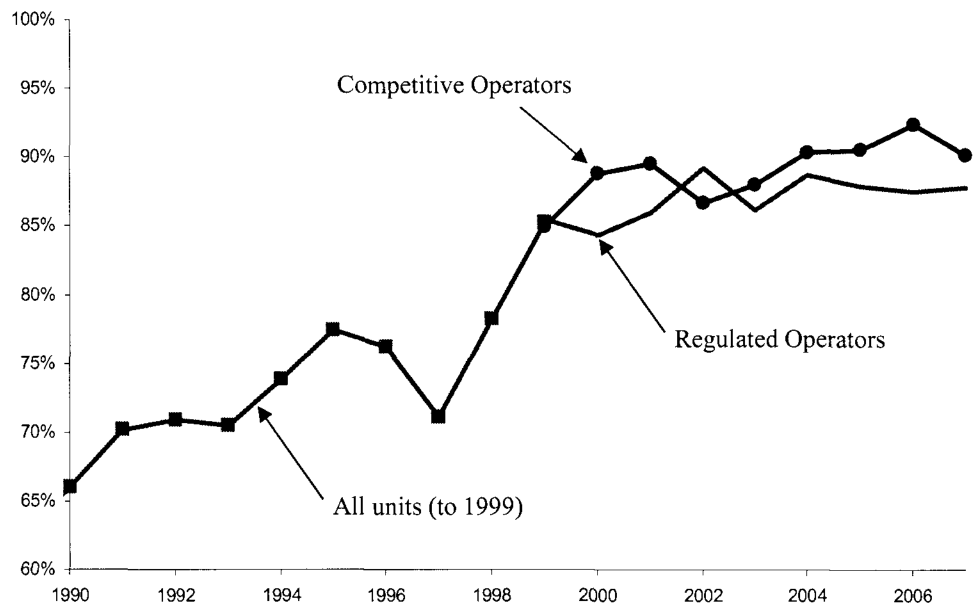
Competitive power plant operators have a strong incentive to maximize the output and capacity factor of baseload units such as nuclear and coal units. As shown in Figure 24, capacity factors of nuclear plants, while generally improving over time, improved dramatically since the time of restructuring from around 70 percent to the 90 percent level. Furthermore, since 1999, nuclear plants operated by competitive generators have realized an average capacity factor that is close to 2 percent higher than that of regulated plants, producing savings of about $350 million per year at current market prices.[69]

[67] Energy Security Analysis calculated prices across the expanded PJM pre- and post- its expansion from PJM Classic, and also examined market heat rates, price convergence across different zones, and price flows over interfaces. They concluded that the PJM region-wide price would have been $0.78/MWH higher in 2005 without expansion, resulting in 2005 savings of over $500 million. (Edward Krapels and Paul Fleming, "Impacts of the PJM RTO Market Expansion," prepared for PJM, November 2005, 58.)

[68] Kira Fabrizio, Nancy Rose, and Catherine Wolfram, "Do Markets Reduce Costs? Assessing the Impact of Regulatory Restructuring on US Electric Generation Efficiency," *American Economic Review*, Vol. 97, No. 4, September 2007, 29. See also James Bushnell and Catherine Wolfram, "The Guy at the Controls: Labor Quality and Power Plant Efficiency," *National Bureau of Economic Research Working Paper No. 13215,* June 2007, 5-6. An earlier analysis of the 1981 through 1999 period found that plant operators most affected by restructuring reduced labor and non-fuel operating expenses by 5 percent or more relative to other regulated IOU plants, and by 15-20 percent relative to government and cooperatively-owned plants.

[69] Capacity factor improvements at divested nuclear plants add about 5 million MWH per year from these plants. We estimate that running these nuclear plants versus running the marginal unit in their particular market produces savings of about $70/MWH (at current forward market prices), leading to annual savings of just under $350 million per year.

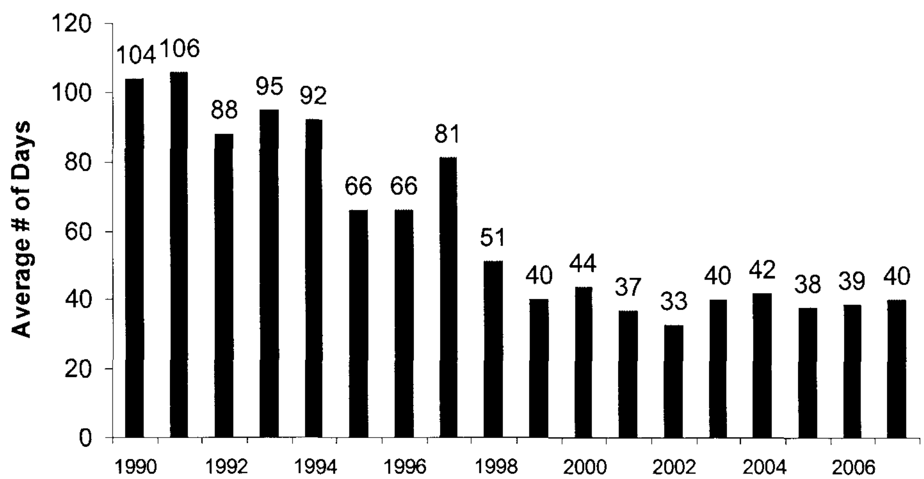
**Figure 24 Improvement in Nuclear Capacity Factors, 1990-2007**




Source: Based on plant-level output data from the Nuclear Regulatory Commission. Several units passed to competitive ownership prior to 1999, but reliable separation of competitive and regulated data is not possible prior to this year.

Restructuring also has led to a consolidation of nuclear plant operators. These firms tend to specialize in the operation of nuclear plants and implement best practices. The improvement in capacity factors occurred mostly through reducing the period of time needed to refuel the plant as well as better management and preventive maintenance. In 1990, the average refueling outage was 104 days, and by 2007, it had been reduced substantially to 40 days, as shown in Figure 25.

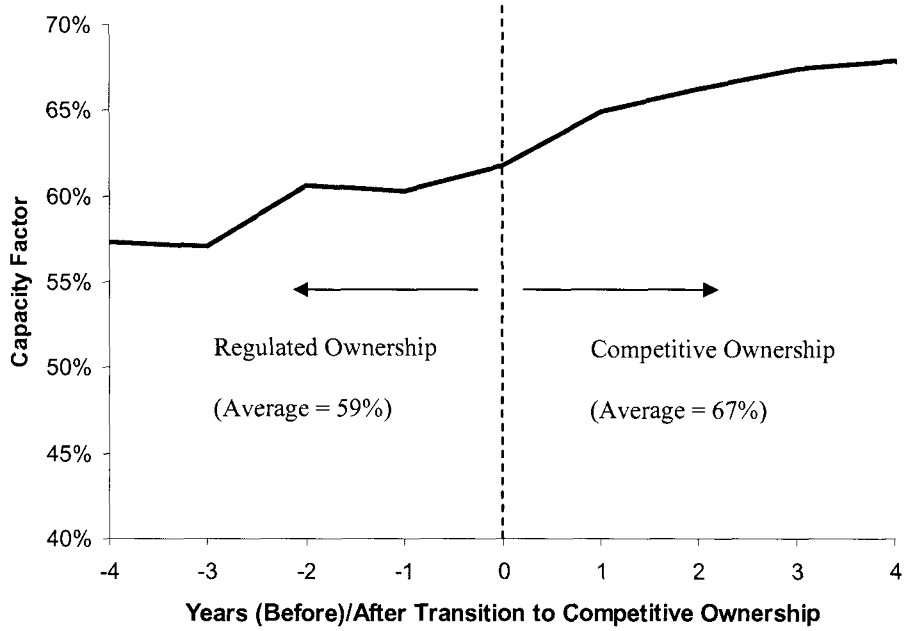
**Figure 25 Reduction in Nuclear Refueling Outage Days**




Source: Nuclear Energy Institute.

The evolution of coal plant operations is also significant. As Figure 26 shows, previously-regulated coal plants that have been acquired by a competitive operator have experienced significant gains in capacity factor and availability after transitioning to competitive ownership and operation, producing savings on the order of $300 million per year at current market prices.[70]

**Figure 26 Improvement in Capacity Factor for Coal Plants Transferred to Competitive Ownership**




Source: Based on data from FERC Form 1 (Annual Report of Electric Utilities) for various years as well as data from the EPA Continuous Emission Monitoring Systems (CEMS) database. Values shown are an average for 55 coal-fired power plants that were either purchased by a competitive operator or transferred to an unregulated generation affiliate.

Finally, restructuring also appears to have led to better fuel efficiencies (i.e., better heat rates) of fossil-fueled plants. Divested generating plants improved their fuel efficiencies compared to other comparable plants. Controlling for output level, deregulated plants used 2 percent less fuel per MWH of electricity produced, averaged across different fuel types than regulated plants, producing savings of about $550 million per year.[71]

[70] Improved capacity utilization at divested coal plants adds about 34 million MWH per year from these plants. We estimate that running these coal plants versus running the marginal unit in their particular market produces savings of about $30/MWH (at current forward market prices and inclusive of environmental costs), leading to annual savings of just over $1 billion per year. Roughly 70% of this value can be attributed to changes in market conditions (such as rising gas prices) and improvements in technology that affected both regulated and competitive plants. The remaining 30% is attributable to gains made by competitive plants in excess of improvements observed at always-regulated plants. Multiplying $1 billion by 30% we arrive at an annual savings estimate of $300 million for the gains attributable to competitive ownership.

[71] James Bushnell and Catherine Wolfram, "Ownership Change, Incentives and Plant Efficiency: The Divestiture of U.S. Electric Generation Plants," Center for the Study of Energy Markets (CSEM) Working Paper Series, March 2005, 21-22.

2) Competition Promotes Efficient Plant Investment and Retirement Decisions

a) The Theory

One of the most significant savings from restructuring is believed to be efficiency gains in long-term investments (sometimes referred to as "dynamic efficiency"). Dynamic benefits are those that can be achieved over a longer term, including changes in the capital stock such as investment in new generation, demand response, and energy efficiency. Economic theory suggests that a properly functioning competitive wholesale market (including customer demand response) will induce the right amount of generating capacity with the appropriate levels of reliability, as well as the right mix of generating technologies in the right locations.

Competitive markets can provide significant improvements in resource planning and capital additions. Price signals, rather than administrative determinations, guide economic retirements and capacity improvements, economic new entry, and environmental compliance strategies. In a competitive market in long run supply/demand equilibrium, prices will approximate long run marginal costs, a figure which includes the cost of capacity and therefore provides for capital recovery. As supply and demand become more balanced over time and the market for bulk power reaches long run equilibrium, prices will increase to the point where capital is recovered. The dynamics of a competitive market continually pushing toward equilibrium are responsible for these forces. If returns exceed full cost recovery, new generation will be built that will tend to drive profits and prices down. On the other hand, if profits are suffering and capital is not recovered, generators will not add capacity. If profits on existing plants do not cover their fixed costs, operators will shut down units, and may make plans for early exit – activities that allow prices to rise.

Markets also provide the necessary incentives for investments in different fuel sources. Competitive generators have the appropriate price signals (including environmental costs) to evaluate the relative economic value and risks of alternative generation fuel sources in order to develop the most economically efficient combination of generation fuel sources over time. New solid fuel (nuclear or integrated gasification combined cycle) or renewable generation will be built when it is economic, that is, when expectations of gas prices and/or $CO_2$ allowance prices are sufficient to make such investments economic on an expected basis. If such plants are not economic for investors, then they will not be built in the absence of regulatory mandates. If a new plant with a particular fuel type can be constructed at a profit based on expected market prices, it will be. This investment decision is similar to that of other capital-intensive industries, as Paul Joskow explains, "investors finance oil refineries, oil and gas drilling platforms, cruise ships, and many other costly capital projects where there is considerable price uncertainty without the security of long term contracts."[72]

Competition makes investors, rather than consumers, responsible for investment decisions with no assured recovery of the investment. In the 1970s and 1980s, a competitive market would have allocated risks appropriately: it would have transferred the risks of technology choice, excess supply problems, and cost overruns from the consumers to the investors. Instead, under regulation, electricity consumers bore these risks. In a competitive market,

[72] Paul Joskow, "Competitive Electricity Markets and Investment in New Generating Capacity," AEI-Brookings Joint Center for Regulatory Studies Working Paper 06-14, May 2006, 39-40.

where a new plant is not guaranteed a return, there is no incentive for investors to over-invest in capital or "gold-plate" investments, overestimate consumer demand for electricity, or build facilities even when costs have significantly increased or slow-downs in load growth no longer require the investment. A competitive market model will allow regulators and customers to avoid future situations in which a utility makes a long-term commitment that later becomes uneconomic and costly for customers. Rather, investors in the competitive market will bear these risks.

b) Early Results – Significant Improvements in Open Access and Price Signals That Support Development of Competitive Generation

To date, significant progress has been made in the development of wholesale markets and non-utility generation. A series of FERC policies and orders has improved investors' access to information that they can rely on to plan and invest in new generation. The Energy Policy Act of 1992 expanded FERC's authority to order utilities to provide transmission service to facilitate wholesale power transactions. In 1996, FERC Order 888 required transmission-owning utilities to offer open access transmission service. FERC Order 889 required utilities to provide information about the availability and the price of transmission service on their system. In late 1999, FERC Order 2000 encouraged the formation of RTOs to further promote competition. These actions have led to considerable improvements in non-discriminatory, open transmission access that facilitate coordination and promote competitive entry into the market.[73]

Most regions that have created ISOs have implemented bid-based security constrained dispatch[74] with locational or nodal pricing. Differences in locational prices highlight transmission congestion within regions to allow an efficient allocation of scarce transmission capacity and to provide market signals that indicate the need to make new investments in either generation, transmission or load response resources. These price signals adjust to changes in supply and demand conditions and allow both investors and regulators to more accurately identify resource needs. As of 2007, about two-thirds of customers in the United

[73] Utilities that own transmission either directly or through an ISO/RTO have developed standardized, cost-based transmission service tariffs to third-parties. Third parties also have real-time information on transmission availability and prices. Utilities are required to interconnect independent power producers to their networks and must provide certain network support services, including balancing services to third parties. Utilities are also required to follow functional separation rules between the operators of their transmission networks and affiliated generators to mitigate self-dealing. Utilities are required to use best efforts to expand their transmission system in order to meet service availability requests when there is not sufficient capacity available. These changes are discussed in more detail in Paul Joskow's paper, "Markets for Power In the United States: An Interim Assessment," *The Energy Journal*, Vol. 27, No. 1 (2006), 5-7.

[74] Bid-based security constrained dispatch refers to a regime under which each generation unit is bid by its operator into a centralized market at a price that the owner sets at its discretion subject to market rules. The centralized market first considers dispatching all available on-line generating resources and power purchases to achieve the lowest possible cost to satisfy load. Once this "pure" economic dispatch is developed, reliability and other constraints (such as transmission congestion) are considered in order to modify the economic dispatch with the minimum increase in cost. Many markets have developed integrated day-ahead, hour-ahead and real-time energy prices based on these bids.

States are served by an ISO or RTO.[75] Many of these changes have led to increased competition from non-utility generation both in restructured and regulated states.

Thus far, the industry also has experienced a significant restructuring of the ownership of generating plants. In 1996, investor-owned utilities ("IOUs") owned 580 gigawatts of capacity. Since 1996, about 100 gigawatts were divested by IOUs and another 100 gigawatts were transferred to unregulated utility affiliates. Between 1999 and 2004 about 200 gigawatts of new generating capacity was completed, about 80 percent of which was owned by unregulated generating companies. By 2004, over 40 percent of the power produced in the United States (excluding federal, state, municipal and cooperative generation) came from unregulated power plants.[76]

More new generating capacity entered the market between 2001 and 2003 than in any other three-year period in U.S. history.[77] Most of this capacity relied on natural gas and was built by unregulated developers using project finance without long-term contracts. When wholesale market prices fell after 2001, many of these projects could not meet their debt obligations and went bankrupt or faced severe financial difficulties.

The experience of the competitive market gas combined cycle build-out of the late 1990s and early 2000s was very different from that of the regulated nuclear capacity additions of the 1970s and 1980s. Figure 27 shows the forward price signals applicable to new build gas combined cycle generation (in the form of the on-peak spark spread, which is the difference between electricity prices and the variable cost of a gas combined cycle).[78]

From late 1998 through early 2001, combined-cycle new entry economics were highly favorable and triggered a huge wave of new CCGT plants. In early 2001, however, the forward price signal dropped well below the threshold needed for new units to make money. This crash in the price signal triggered a quick response from competitive builders, and a much slower response from regulated builders. For competitive builders, 78 percent of capacity with a planned in-service date of 2003 or later (relatively little of which would have been sunk by late 2001) was ultimately cancelled, while for regulated builders only 37 percent of capacity was cancelled. Comparing this to the nuclear industry experience we can see that: 1) a price signal improves the responsiveness of generation builders to changes in market conditions, and 2) regulated builders still respond much less efficiently to price signals than do non-regulated builders. This experience also demonstrates that, regardless of the market structure, investors in capital-intensive generation plants face enormous risks and make mistakes; but, in a competitive market, the recognition of and response to these mistakes is much more rapid than in a regulated environment. Private investors responded much more quickly to the crisis of the early 2000s than regulated builders did in the 1970s and 1980s. Further, the crisis of the early 2000s had little impact on customers in non-

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[75] ISO/RTO Council, *About the ISO/RTO Council (IRC),* 2007, Accessed 24 March 2008, http://www.isorto.org/site/c.jhKQIZPBImE/b.2603917/k.7A3F/About_the_IRC.htm.

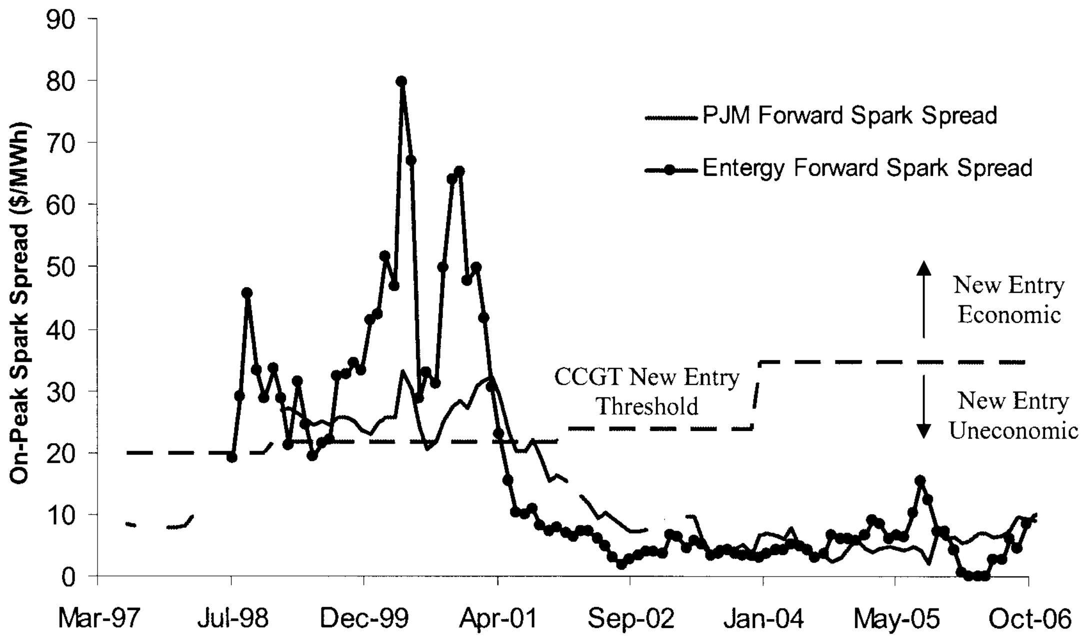
[76] Joskow, "Markets for Power in the United States," 7.

[77] Joskow, "Markets for Power in the United States," 7.

[78] While competitive power plants were built throughout the country, reliable forward market price information going back to the 1990s is limited to only a few locations. Entergy and PJM provide the longest-running forward market datasets available.

regulated states, since unlike prior investments in new capacity; unregulated investors – not ratepayers – bore the risk of these uneconomic investments. We estimate that private generation developers lost about $30 billion (in 2007 dollars) in economic profits over the period 1996 to 2005 – losses that likely would have been paid for by ratepayers had they been incurred by regulated builders.

**Figure 27 Decline of Gas Combined-Cycle New Entry Economics in 2001**




Source: Based on year-ahead forward market data from Bloomberg, Inc., Intercontinental Exchange, and the New York Mercantile Exchange.

Currently, locational market energy and capacity prices in constrained regions, such as Eastern PJM, are providing price signals for new entry by both generation and demand response resources – and these signals have generated a response from investors. PJM has experienced 10,000 MW of net new resources since the Reliability Pricing Model ("RPM") auctions were implemented.[79] Further, several generators in PJM plan to build additional new capacity in response to RPM. For example, PSEG Power recently announced plans to build up to 1,000 MW of peaking capacity in response to recently-observed forward energy and capacity prices.[80] Exelon is actively pursuing development of a 600 MW combined cycle plant and Reliant reversed plans to mothball a 315 MW gas/oil plant in Pennsylvania.[81] Constellation and PP&L also announced plans to expand capacity and return mothballed capacity in PJM.[82] Similarly, over 1,300 MW of new demand response resources have been

[79] "PJM Reliability Pricing Model Draws Largest Amount of New Capacity So Far," PJM Press Release, 1 February 2008.

[80] "PSEG Plans Up to 1,000 MW of Peakers," *Megawatt Daily*, 15 October 2007.

[81] "Capacity Prices Support PJM Additions: Reliant," *Megawatt Daily*, 2 May 2008.

[82] "Constellation, PPL See Gold In Tight Markets," *Megawatt Daily*, 6 September 2007.

added in PJM over the first four RPM auctions.[83] The ISO-New England also completed its first forward capacity auction in February 2008 and received an excess of bids to meet its targeted reliability margin at the auction's floor price.[84] The auction resulted in 626 MW of new generating capacity and 1,188 MW of new demand resources from energy efficiency, demand response and distributed generation.[85] Many of the new resources are concentrated in areas of high demand, including Connecticut and Massachusetts.

Lastly, the restructuring process in many regions has been accompanied by more efficient environmental compliance. One study concludes that utilities in restructured states have been able to meet environmental requirements with less expensive pollution abatement techniques than regulated utilities, since regulated utilities tend to favor more capital-intensive approaches that can be included in rate base:

> Although state regulators have allowed electricity generators to earn a positive rate of return on capital investments in pollution control equipment and recover the average costs of operating pollution controls and purchasing permits (profits from the sale of permits are also passed through to rate payers), the opportunity costs of using or holding allocated allowances are not reflected in regulated rates. Regulated firms have an incentive to choose compliance options that require more capital investment relative to pollution permit "inputs" than is consistent with cost minimization.[86]

These capital-intensive solutions tend to be more costly for customers.

### 3) Competition Promotes Efficient Customer Consumption Decisions

#### a) The Theory

The retail price of electricity also provides a valuable price signal to customers that may impact customers' time of electricity use, overall level of electricity use, fuel choice, and investment decisions. Unfortunately, most markets for electricity suffer from the lack of customer demand response. This lack of customer response is reinforced by retail rate design in both regulated and many restructured states. As shown earlier in Figure 23, conventional utility tariff rates based on average costs often diverge substantially from marginal cost market prices. Tariff rates, when exceeding market prices, limit the economic use of electricity, prevent economic development, and encourage customers to bypass the system even when it is uneconomic to do so. Tariff rates, when below market prices, encourage

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[83] PJM Interconnection, "2010/2011 RPM Base Residual Auction Results," 1 February 2008.

[84] "ISO New England's First Forward Capacity Market Auction Completed Successfully," ISO New England Press Release, 6 February 2008.

[85] "Demand-Side Trumps Plants in ISO-NE Auction," *Megawatt Daily*, 14 February 2008.

[86] Meredith Fowlie, "Emissions Trading, Energy Restructuring, and Investment in Pollution Abatement," University of California Energy Institute Center for the Study of Energy Markets, Paper CSEM WP-149, November 2005, 8-9.

customers to over-consume electricity especially during high-priced hours when capacity is in short supply and energy is expensive to produce.

This mismatch between conventional retail rates and market prices creates several problems. First, it results in inefficient use of electricity. The failure to induce customers to shift consumption from higher-price on-peak periods to lower-price off-peak periods creates poor capacity utilization of both baseload and intermediate power plant resources, and requires a greater level of installed capacity in order to accommodate higher peak loads. Second, because customers do not see a time-varying market price, they are generally unable to curtail their usage in times of high demand and/or supply scarcity. As a consequence, demand for electricity is almost completely inelastic in the short-run; during periods of scarcity, market prices can increase by orders of magnitude without inducing any reduction in load. Third, to the extent that regulated or default service price cap rates do not reflect overall market price levels, even over longer time periods, retail customers are forced to make investment decisions based on distorted price signals, which leads to over- or under-investment in energy efficiency and inappropriate fuel choices.

In contrast, when customers see competitive, market-based marginal prices, there are several types of efficiency benefits. Customers can respond to changing power market prices and reduce their electric bill by shifting or curtailing their consumption. An extensive body of research has been conducted to estimate customer response to changing electricity price signals. This research suggests that electricity is similar to most other commodities, whereby decreasing prices leads to greater consumption and increasing prices leads to less consumption, all other things being equal. While customer response is hard to measure precisely, the research in the industry and growing empirical results convincingly demonstrate that customers do respond to changes in electricity prices, and relatively low customer response can still result in significant benefits to society. Some conservative estimates suggest that a 10 percent increase in the average price of electricity will result in a one percent or more decrease in electricity demand,[87] and with each one percent reduction in demand nationwide, the industry could avoid $CO_2$ emissions of 30 million tons per year and the need for nearly 5 gigawatts of new baseload/intermediate generating capacity, saving $10 to $20 billion or more in capital investment.[88]

Market price signals also guide customer investment decisions in energy efficiency equipment and business expansion and productivity enhancements. Customers also can benefit by investing in new technologies that automatically regulate the power consumption of certain appliances or machines (commonly referred to as "direct load control"). For example, automated price signal thermostats that control air conditioning and hot water heaters have been used in residential markets and heat and energy storage systems have been installed on a commercial scale. There also is renewed interest in hybrid electric cars. These cars with advanced battery technology use a small amount of liquid fuel but can "plug-in" to the electric grid. These cars could serve as distributed off-peak storage of electrical energy,

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[87] Christian Crowley and Frederick Lutz, "Weather Effects on Electricity Loads: Modeling and Forecasting," Study Prepared for EPA, 12 December 2005; Steven Wade, "Price Responsiveness in the AEO2003 NEMS Residential and Commercial Buildings Sector Models," Study Prepared by the Energy Information Administration, 2003.

[88] Assuming a capital cost for low-carbon baseload/intermediate generation of $2,000/kW to $4,000/kW.

using off-peak energy to displace oil consumption as well as potentially provide power for individual homes.[89] Market pricing makes the value of such products and equipment more visible to customers, and competitive providers of these products and services have strong incentives to help customers capitalize on their value.

Demand response also can provide customers with reliability benefits by reducing the likelihood of involuntary curtailments. While the relationship between market prices and regulated average embedded costs will vary depending on the weather, time of day, time of year, supply and demand balance, and other factors, providing customers with these market price signals will ultimately lead to more efficient customer consumption and investment decisions both in the short and long term. Here again, competitive providers have strong incentives to develop innovative ways to assist customers in taking advantage of these opportunities.

More efficient price signals and demand response also complement and improve the performance of the competitive wholesale market, resulting in better resource and generation investment decisions and enhanced system reliability. The integration of supply and demand resources will improve system load factors and defer capital investments in generation, and may result in a shift in the mix of peak versus baseload capacity needed. Market pricing can enhance system reliability by enabling price to balance supply and demand. When demand tightens, prices will increase; customers will see and respond to the price increases by reducing consumption; demand will fall, prices will fall, and the system will balance. The ability of customers to lower consumption during high marginal cost periods also provides the added benefit of mitigating market power concerns when capacity is scarce.

Competition improves retail pricing efficiency by reducing subsidies inherent in "one size fits all" rates. Traditional utility rates typically include cross-subsidies within and among rate classes. For purposes of ratemaking, customers within a rate schedule are generally assumed to be homogenous in terms of consumption patterns. In reality, however, customers within the same rate schedule may have very different consumption patterns. Competition allows retailers to develop tailored pricing by customer, which will more appropriately reflect individual consumption patterns of a customer and will drive costs out of the system as customers modify their behavior in response to the true costs of supply.

Finally, customer demand response and customer-owned resources provide other benefits, including enhanced reliability to protect customers from outages, reduced air emissions, and utility deferral of transmission and distribution upgrades.

#### b) Early Results – Increase in Retail Market-Based Pricing and Customer Demand Response

Several states and utilities within restructured markets have taken actions to increase economic demand response and have expanded market pricing initiatives. While demand response programs, time-of-use pricing, and interruptible programs have also been

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[89] Peter Huber and Mark Mills, *The Bottomless Well: The Twilight of Fuel, the Virtue of Waste, and Why We Will Never Run Out of Energy* (New York: Basic Books, 2005) 75-90. See also "Can better batteries pummel US oil addiction in a few years?" *Restructuring Today*, 29 January 2008.

implemented at a number of regulated utilities over the years, such programs ultimately must be tied to market-based, marginal cost rates in order to be efficient.[90] As transition periods are completed, customer rates increasingly reflect market prices and more customers are experiencing more frequent price adjustments that vary by year, by season, by time-of-use period, or by hour. More customers, especially large C&I customers, are beginning to see the proper price signals associated with their consumption at a specific place and time. There are at least sixteen utilities in five states that now offer hourly price default service to large C&I customers.[91] Competitive retailers in Texas, where there is no longer utility-provided default service, also offer Market Clearing Price for Energy ("MCPE") products based on spot market electricity prices. Customers on hourly price default service or MCPE receive a clear price signal and have the ability to act immediately to reduce demand during times of high prices or increase their consumption during times of low prices. These benefits are clearly transparent in a competitive market that allows retail pricing to match real-time market conditions.

Currently, there is about 21,000 MW of demand response in the United States, consisting of capacity (73 percent), energy (15 percent), and ancillary services (12 percent).[92] The level of interest in demand response has increased as generation costs have increased and as market prices have become more visible. RTOs and utility companies have established economic curtailment programs and demand reduction programs that are tied to these visible energy and capacity markets. As shown in Figure 28, RTO and ISO regions with organized wholesale markets lowered system peaks by over 8,300 MW on peak days during the summer of 2006.[93]

These customer demand resources can avoid substantial capital costs in peaking capacity. As an example, 8,300 MW of customer demand response could avoid roughly $3.7 to $5.8 billion of capacity costs.[94] In addition, by reducing demand at critical times, system operators can enhance system reliability on short notice in the event of unexpected generation or transmission failures and/or extreme weather conditions. Demand response plays an even more valuable role in load pockets, such as in southwest Connecticut and New York City-Long Island,[95] since demand response typically requires shorter lead times and can be less costly than building new generation, transmission, or distribution facilities. Several RTOs

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[90] For example, many interruptible customer load programs provided by regulated utilities traditionally were used only in cases of "system emergencies" or as a means to offer fixed discounts to large users, but in developing competitive markets, the economic use of customer resources is increasing.

[91] These include utilities in Maryland (APS, BGE, DPL, Pepco), New Jersey (AECO, JCPL, PSEG, RECO), Illinois (ComEd), New York (NIMO, CH, NYSEG, O&R, RGE, ConEd), and Pennsylvania (DLC).

[92] ISO/RTO Council (IRC), Markets Committee, "Harnessing the Power of Demand: How ISOs and RTOs Are Integrating Demand Response Into Wholesale Electricity Markets," 16 October 2007, 8.

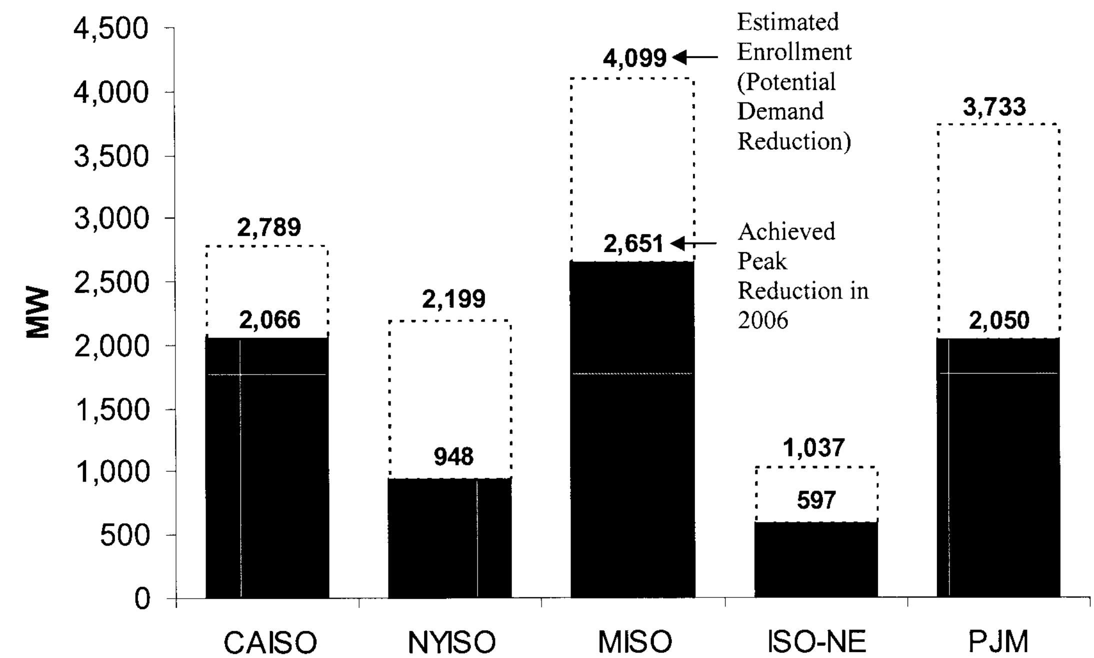
[93] "2007 Assessment of Demand Response and Advanced Metering," FERC Staff Report, September 2007, i.

[94] This assumes that the cost of a peaking combustion turbine ranges from $450 per kW, as it did around 2006, to $700 per kW, which is a more current estimate. (PJM, "PJM RPM Proposed CT Cost of New Entry (CONE) Update, corrected 12-04-07, http://www.pjm.com/markets/rpm/downloads/20071204-rpm-ct-cost-new-entry-update.xls.)

[95] FERC, "2007 Assessment of Demand Response and Advanced Metering," 6.

also report that demand response reductions during peak hours have reduced wholesale prices, particularly during periods of price spikes.[96]

**Figure 28 Customer Demand Response In RTO/ISO Programs, Summer 2006**




Source: "2007 Assessment of Demand Response and Advanced Metering," FERC Staff Report, Table B-1, September 2007. Enrollment figures from FERC Staff analysis. Achieved peak reductions based on called demand response in summer of 2006. CAISO: Emergency Stages 1&2, FERC estimate based on difference between forecast and actual peak load; NYISO: Emergency DR activated, "Responses to FERC," FERC Wholesale Demand Response Technical Conference; MISO: Max Gen Warning NERC EEA2, actual reductions based on MISO survey to Balancing Authorities; ISO-NE: OP-4 Action 12, ISO-NE 2006 Annual Markets Report, June 11, 2007, 116; PJM: Full Emergency Load Response Mid-Atlantic only, "PJM 2006 State of Market Report," Vol. 1, 12-13.

More recently, demand resources have been included in forward capacity markets and certain ancillary services markets, so that they can be assessed along with competing generation resources.[97] Third party firms, who aggregate demand reductions across customer groups,

[96] In competitive spot markets, demand response on the margin can lower the overall price for all energy traded in the market. PJM reported estimated energy payment reductions of more than $650 million in one week during 2006. (PJM, "Early Aug. Demand Response Produces $650 Million Savings in PJM," PJM press release, 17 August 2006.) ISO-New England attributed average savings of $1.74/MWH during hours with interruptions over the period April to September 2006. (ISO New England, "2006 Annual Markets Report," 11 June 2007, 11.) The Midwest ISO found a reduction of $100 to 200/MWH in market clearing prices during a peak day in August 2006. (FERC, "2007 Assessment of Demand Response and Advanced Metering," 6-7.)

[97] In the first 2007 capacity auction in PJM, demand response offers that cleared were about 41 percent of the new capacity that cleared (127 MW versus 311 MW). In the second auction in 2007, the demand response offers that cleared increased to 536 MW. (PJM, "PJM Completes First Reliability Pricing Model Auction," PJM News Release, 16 April 2007 and PJM, "PJM Reliability Pricing Model Producing Results," PJM News Release, 13 July 2007.) The ISO-NE forward capacity market allows different types of demand resources to participate, including energy efficiency, load management, distributed generation, and real-time demand response.

are increasingly able to bid customer demand resources into markets in an integrated manner side-by-side with supply resources.[98] Customer enrollment in RTO/ISO demand reduction reliability and economic programs also has increased, with the total number of MW enrolled growing by more than 50 percent since 2003 in the Eastern markets of PJM, ISO-NE, and the NYISO.

The level of interest in advanced metering infrastructure ("AMI") has also increased and utilities recently have announced plans to install more than 40 million advanced meters during the period 2007-2010. The increase in AMI market activity, as measured by the number of meters planned or installed, has nearly tripled from 2005 to 2006, and is projected to double again in 2008.[99] While advanced meters are being installed in both regulated and restructured states and not all of these plans will be implemented, the installation of more sophisticated metering and control technology will allow retail customers in competitive markets to respond efficiently to market energy prices and to provide capacity as demand-side bidders in competitive wholesale markets. Expansion of these customer resources, especially among smaller customers, will become more feasible with smart metering, faster internet connections and improvements in direct load control technology. Finally, as more retail customers begin to see accurate market price signals, customer demand response will increase and competitive suppliers will have the incentive to offer expanded choices of products that will manage customer load and hedge market price risks. For example, some competitive suppliers offer large C&I customers "swing" products that fix a portion of the customer bill based on some defined consumption pattern, but allow prices to adjust with market when consumption deviates from certain levels. Competitive suppliers have strong incentives to provide these types of new products and services when considered valuable to customers.

## E. Retail Competition is Still Developing and Provides Additional Benefits

### 1) The Theory

In a well-designed market, retail competition will produce the most efficient outcomes, provide customers with more choices and improve customer value and customer satisfaction. First, retail competition increases customer choice in suppliers and in products. Traditional utilities typically offered "one size fits all" service with limited service options and no choice of supplier. Retail choice allows customers to choose their supplier, manage their demand, and determine the level of risk they want to assume. Second, competition leads to service improvements and innovation. Competition provides new incentives to develop value-added services and product offerings as competitive retailers gain access to customers and become more familiar with their needs and desires. Competitive retailers have strong incentives to attract and retain existing customers to maximize the lifetime value of the consumer in order

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[98] For instance, EnerNOC reports that it currently manages over 1,100 MW of customer demand response (EnerNoc, "EnerNOC Reports Fourth Quarter and Year-End 2007 Financial Results," EnerNoc News Release, 27 February 2008) and Comverge reports that it has over 600 MW of customer capacity under contract (Comverge, "Comverge Announces 2007 Third Quarter Financial and Operating Results," Comverge News Release, 6 November 2007).

[99] FERC, "2007 Assessment of Demand Response and Advanced Metering," 31.

to capture market share and enhance profitability.[100] This can be accomplished through better understanding of customer desires (e.g., recognizing that customers are different and developing products that address customers preferences: length of fixed price term, renewable energy, demand response, smart energy, quicker response times, eliminating busy signals, and so forth). Finally, retail competition aligns the industry value chain with the customer. Competitive suppliers have strong incentives to satisfy customer demand for supply and services, while avoiding the generation overbuild problems and the one-size-fits-all service of the 1970s and 1980s.

### 2) Early Results – Retail Competition is Still Developing and Provides Additional Benefits

The first retail competition and restructuring programs began in Massachusetts, Rhode Island, and California in early 1998. By the end of 2000, more than a dozen states had initiated their own restructuring programs. While the slow pace of the development of retail competition has disappointed many observers both within and outside the electric industry, very few states have enacted the rules and infrastructure necessary to allow retail competition to develop. Nonetheless, overall customer switching to competitive suppliers has more than quadrupled from 22 GW in 2001 to 91 GW in 2007 of customer peak load as shown in Figure 29.

Across the United States, approximately 480 terawatt-hours from 8.3 million customers are currently served by competitive suppliers.[101] This competitive load represents about 30 percent of the eligible load in retail access states, and most of the shopping load (over 80 percent) is non-residential.[102] Competitive markets have expanded as transition periods have ended and retail rates have become more aligned with market price levels. In particular, large C&I customer switching rates have grown significantly in certain parts of the country. In fact, the majority of large C&I load is shopping in service areas within Texas, New York, New Jersey, Maryland, and Massachusetts, with switching levels that range from 60 percent to 98 percent.[103]

Retail competition for residential customers thus far has developed largely in two states where market rules fostered competitive market development – broadly in the ERCOT area of Texas and less broadly in New York. Although residential customer shopping has been limited in other parts of the country, small C&I customers in restructured states have had a larger number of competitive service options and somewhat higher switching levels than residential customers. This difference is due in part to state regulators allowing competition at the large C&I level to gradually work its way down to smaller customers.

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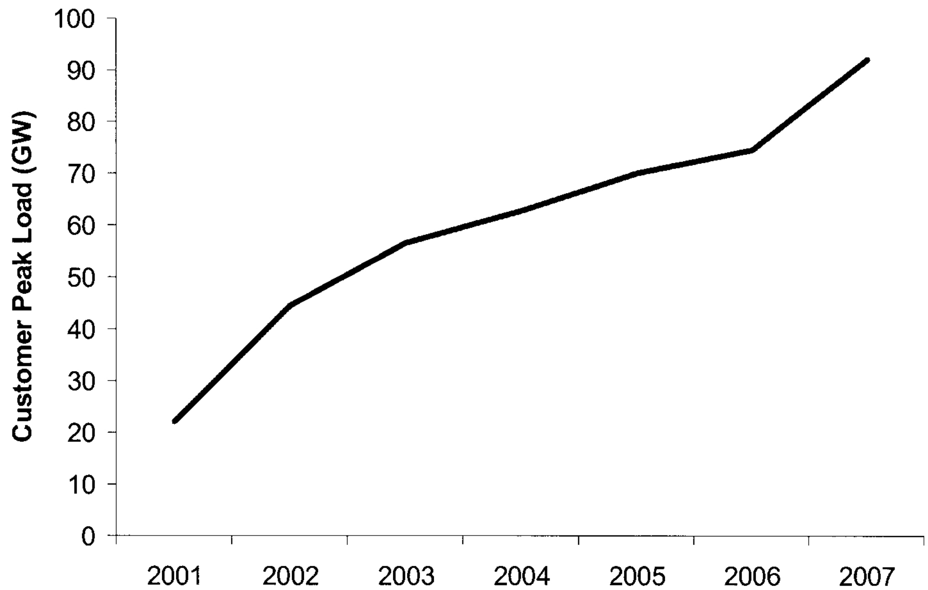
[100] Customer acquisition costs can be high, particularly for smaller customers. Retail suppliers, therefore, have strong incentives to retain customers.

[101] KEMA, "Sharp Increase US Competitive Power Market," KEMA News Release, 6 August 2007.

[102] KEMA, "Sharp Increase US Competitive Power Market."

[103] While jurisdictions have different definitions of what constitutes a "large" customer, more and more customers are facing hourly or short-term market prices over time as regulators expand the definition of a "large" customer and become more comfortable with market pricing to smaller size customers.

**Figure 29 Increase in U.S. Retail Shopping Levels, 2001-2007**




Source: KEMA

Retail competition among residential and smaller customers in many jurisdictions has been hampered by below-market default service rates, lack of standard market rules, policies that favor utility default service, and a variety of other factors. While default service rates that reflect market price levels promote retail competition, jurisdictions that have established fixed default service rates at below-market levels have virtually eliminated retail competition.[104] In many ways, retail competition – and the lack thereof – is a function of policy decisions made by regulators and politicians.[105] In service areas where substantial customer switching has occurred, it has been accompanied by a regulatory commission, legislature, and/or utility that has allowed market-based default pricing.

In markets with significant retail competition, customers can choose new suppliers and products. In Texas, the most active retail market in the United States, more than 26 retail suppliers provide over 90 different residential products in each service area.[106] Customers

[104] In some instances, "blended" default service rates, which are based on the average prices from a mix of wholesale supply contracts, also have not been conducive to retail competition. Blended average market-based rates resulting from competitive solicitations at different points of time provide customers rate stability, but they can differ from prevailing market prices at a particular point in time. During prolonged periods of rising market prices, this makes it difficult for retail suppliers to attract new customers, since utility default service rates are likely to be lower than current market price offers. This has contributed to the lack of retail shopping among residential and small C&I customers in some jurisdictions that rely on a portfolio of laddered supply contracts.

[105] A key question for policymakers is how often utility default service rates should adjust to changes in market prices. In general, a reasonable transition to market prices that adjust more often will improve economic efficiency and customer demand response; but as a practical policy matter, the optimal frequency often depends upon a number of factors, including customer sophistication, market price volatility, the number of competitive service alternatives, what customers are accustomed to, and the costs and benefits associated with exposing customers to greater price volatility.

[106] *Texas Electric Choice, 2008*, Public Utility Commission of Texas, accessed 1 April 2008, www.powertochoose.org.

have a wide range of choices in contract length, pricing options, and exposure to risk. Contract lengths offered by retail suppliers range from one month to many years. Pricing may vary by hour, may be indexed to wholesale prices, may be completely fixed, or may have some combination of fixed and variable prices. Customers can choose among varying levels of green power. But in all cases, prices reflect the current market price for the product selected. Customers choose the product they wish, including their desired level of market price stability. Depending on the individual needs and desires of market participants, short-term commodity fluctuations can be borne by speculators, generators, retail suppliers or customers.

Competition also has led to service improvement and innovation. Retail suppliers provide "green" products, manage price and other risks, and offer load management and energy efficiency services that reduce and shift consumption during peak periods. Retail suppliers can aggregate multiple customer locations and provide bundled services, such as total energy management for other fuels (gas, oil, etc.). As retail suppliers have grown in size, they have been able to lower their administrative overhead costs on a per unit basis. The top competitive suppliers in terms of size currently supply between 10,000 and 20,000 MW of customer peak demand, which is equivalent to that of a large-sized regulated utility.

Nationally, it is clear that retail markets are still evolving and we are still in the early stages of retail market development. Unfortunately, price increases driven by commodity costs have caused regulators in many states to react negatively to a perceived lack of control over price. The reluctance of regulators to allow utility default service to reflect market prices in the face of escalating prices only exacerbates the problem. Given the lack of market-based pricing for utility default service in many parts of the country, it is not surprising that many customers still remain on utility default service. Thus, customer switching statistics should not be relied upon to justify the failure of retail markets. Rather, the success of retail competition should be judged by the new value-added services,[107] market-based pricing, and efficient customer consumption decisions that competition encourages. It also is worth noting that in areas where retail rates more closely reflect market prices, electric retail shopping development compares favorably to the telecom industry. Six years after AT&T's divestiture, AT&T still had more than a 60 percent share of the long distance market.[108] In 1990, six years into a competitive retail electric market in Texas, the incumbents' share of their traditional markets is less than 60 percent.[109]

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[107] Paul Joskow originally suggested this notion in his article, "Why Do We Need Electricity Retailers? or Can You Get It Cheaper Wholesale?," 13 February 2000, 4-5. He concluded that the success of retail competition should be judged by the new value-added services it brings, not by the number of customer who switch from default service. He further adds that regulators who focus on retail switching statistics and who are subsidizing customer switching are likely to be making customers worse off than if the default supplier simply provided them basic electricity service at the spot market price.

[108] Federal Communications Commission, Industry Analysis and Technology Division "Statistics of the Long-Distance Telecommunications Industry," May 2003, pg. 17, Table 7.

[109] ERCOT, *Retail*, 2008, Electric Reliability Council of Texas, accessed 25 March 2008, http://www.ercot.com/mktinfo/retail/index.html. See Historical Number of Premises Switched January 14, 2008.

## F. Other Industries Illustrate the Benefits of Competition

The benefits of competition are evidenced by the experience of other industries that have deregulated (e.g., airlines, telecommunications, and trucking), other competitive industries in the U.S., and electricity deregulation in the United Kingdom.

**Figure 30 Overview of Deregulation in Other Industries**

| | Pre-Deregulation | Deregulation | Post-Deregulation |
|---|---|---|---|
| **Airlines** | • Civil Aeronautics Board determined routes, set fares, regulated entrance into markets, and approved mergers and acquisitions. | • Airline Deregulation Act of 1978 mandated that domestic route and rate restrictions be phased out over four years. | • Decline in fares, an increase in passenger miles, new ways to improve asset utilization, and new services. |
| **Telecom** | • Federal Communications Commission imposed service requirements at regulated rates. Any deviation required government approval. | • The Justice Department's antitrust suit forced AT&T to divest its regional local exchange companies in 1984.<br>• The Telecommunications Act of 1996 opened up competition between local telephone companies, long distance providers, and cable companies. | • Significant improvement in technology, lower long-distance rates, and numerous new products and services. |
| **Trucking** | • The Interstate Commerce Commission regulated operating permits, approved trucking routes, set tariff rates and required market entrants to apply for certificates of public convenience and necessity. | • Motor Carrier Act of 1980 eased regulation of entry and pricing and eliminated most restrictions on commodities and routes. | • Significant decline in rates, improved service quality, reduced empty return hauls, reduced complaints, simplified rate structures, and an increase in new entry. |
| **U.K. Electricity** | • Central Electricity Generating Board was responsible for central planning of all aspects of electricity generation, transmission and investment in England and Wales. | • The Electricity Act of 1989 established a wholesale pool, broke down existing vertical monopoly structures, and eventually led to the privatization of regional electricity companies and retail access. | • Lower electric rates and a greater variety of retail products. |

As suggested by Figure 30, the benefits of competition in these cases are clear and definitive. Compared to other industries that have deregulated, electric restructuring in the U.S. has proceeded in a patchwork, state-by-state fashion, often with prolonged transition periods and rate stabilization plans. Furthermore, most U.S. electricity markets that are today considered "restructured" lack most of the retail customer market-based pricing flexibility that was one of the critical elements of deregulation in industries such as airlines and trucking. Ultimately, however, the underlying economic forces that govern these other industries are also present in the electricity industry, and we would expect restructured electricity markets to provide similar results over time, provided regulators remain supportive of competition and efforts to improve market price signals to retail customers. In particular, competitive markets will encourage 1) a more efficient utilization of resources, 2) increased customer choice and access to products and services, 3) technological innovation, 4) elimination of cross-subsidies, and 5) lower prices.

1) More Efficient Utilization of Resources

Competition promotes more efficient utilization of resources on both the supply and demand side. On the supply side, firms that receive a competitive rather than an average cost-based price for their output have a strong incentive to efficiently utilize their productive resources and reduce operating costs. On the demand side, firms in a competitive, deregulated market will have flexibility to tailor their prices based on their products' differing value to different consumers at different points in time. This pricing flexibility aligns the marginal cost of production with the value customers' place on the product, resulting in a more efficient utilization of productive resources over time.

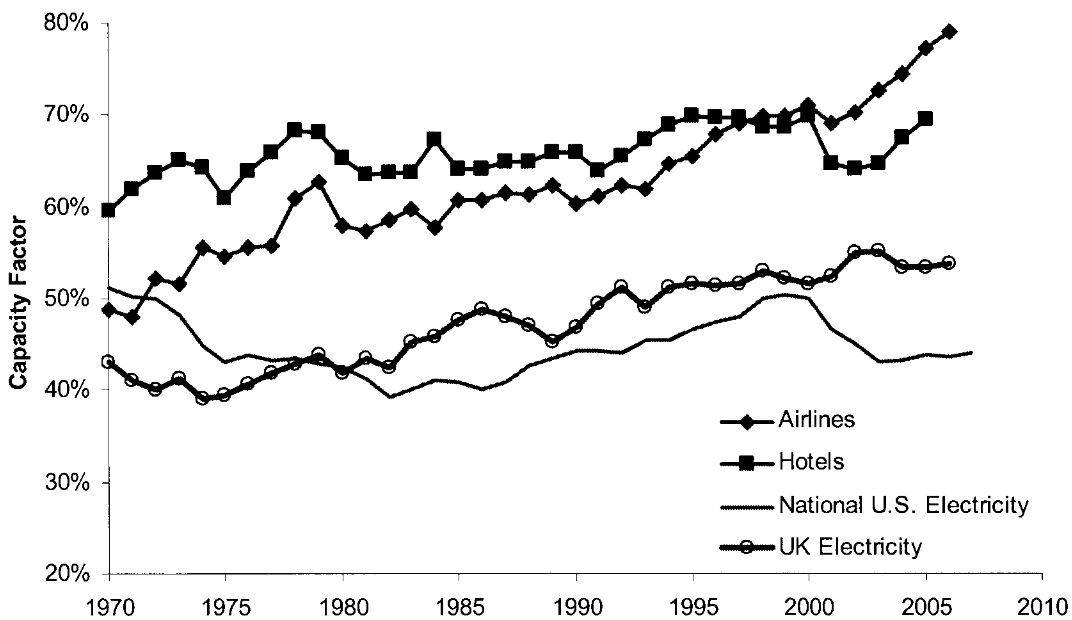
The deregulation of the airline industry provides an example of both these supply and demand effects at work. Prior to deregulation, airlines received a regulated cost-based price and were restricted by regulation to an inefficient point-to-point route structure. This command-and-control approach resulted in considerable excess capacity – load factors (the fraction of seats filled on an average flight) averaged about 50 percent in the decades prior to deregulation. On the supply side, deregulation provided airlines with strong incentives to reduce costs and the ability to improve utilization of their aircrafts. Deregulation exposed airlines to a competitive price signal and allowed them flexibility in developing their route structure to best fit their operations. The result was a move to a more efficient hub-and-spoke routing system as well as stronger emphasis on minimizing turnaround times, maintenance downtime, and matching capacity to demand. Furthermore, on the demand side, removal of price regulation allowed airlines to tailor their pricing to different groups of customers to better match supply and demand over time. For example, airlines were able to time-differentiate their fares such that late-booking, time-sensitive customers on heavily booked flights were charged a higher price while customers with more time flexibility could shift their travel to another flight and receive a lower price. Many customers currently can buy discounted tickets with advance purchases, weekend stays, and non-refundable tickets. By using price as a tool to allocate a limited number of airline seats to the appropriate passengers, airlines could offer discounted prices for seats that would otherwise not be filled and improve capacity utilization. This price and route flexibility, along with intense competitive cost pressures, led to significant improvements in the utilization of airline resources. The overall effect of these changes on resource utilization was dramatic: carriers added more seats on their planes – the average went up from 136.9 in 1977 to 153.1 in 1988 – and succeeded in filling a greater percentage of those seats.[110] Load factors remained between 50 and 55 percent in the years immediately preceding deregulation, but increased after deregulation, reaching 77 percent by 2005.[111]

[110] Alfred Kahn, Airline Deregulation, 2002, The Concise Encyclopedia of Economics, Accessed 26 March 2008.

[111] Severin Borenstein and Nancy Rose, "How Airline Markets Work, or Do They? Regulatory Reform in the Airline Industry," 30 October 2006, 22.

In general, we expect the electricity industry to also show improvements in resource utilization when and if it transitions from today's patchwork and incomplete implementation of restructuring to a broader and deeper form of competition. Figure 31 compares capacity utilization in the U.S. electricity industry with several other capital-intensive industries that feature a relatively non-storable or perishable product.[112] These other industries include: a) airlines (which deregulated in 1978), b) hotels (which have always been a competitive industry), c) and U.K. electricity (which began introducing elements of competition in the early 1990s).

**Figure 31 Capacity Utilization in Selected Capital-Intensive Industries**

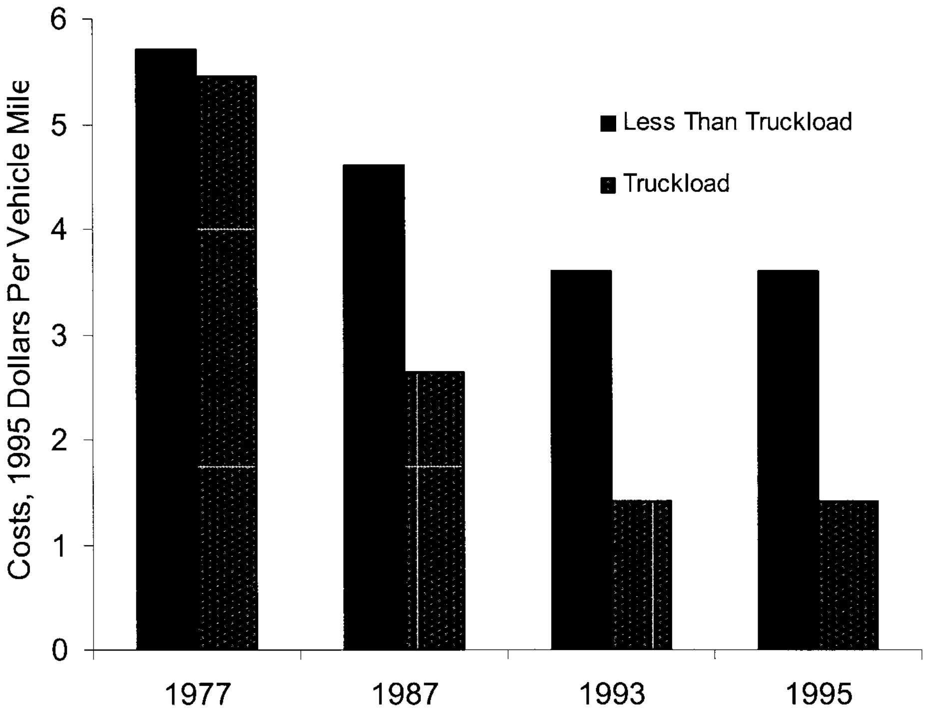



Sources: Airlines Pre-1990: Air Transport Association (http://www.airlines.org/economics/traffic/Annual+US+Traffic.html); Post-1990: U.S. Bureau of Transportation, *National Transportation Statistics*, Table 4-21. Hotels: PKF Hospitality Research, *Trends in the Hotel Industry, 2005*. U.S.: Edison Electric Institute, Historical Statistics of the Electric Industry to 1992, and Energy Information Administration, State-Level Electricity Spreadsheets, 1990-2006. U.K. Electricity: U.K. Department for Business, Enterprise, and Regulatory Reform, *Digest of United Kingdom Energy Statistics*, various years.

The trucking industry also experienced significant declines in operating costs (which include both improved utilization of capital stock as well as reductions in variable operating costs) following deregulation in 1980. As Figure 32 shows, real operating costs per vehicle mile dropped by 35 percent in the less-than-truckload sector ("LTL") for shipments less than 10,000 pounds and by 75 percent in the truckload sector ("TL") for shipments over 10,000 pounds between 1977 and 1995.

[112] Capital-intensive industries with storable products (such as iron and steel, refining, and pulp and paper) tend to have higher capacity utilization than the electric industry with limited storability. The reason for this is that there is little need for a "cushion" of rarely-utilized peaking capacity to meet peak period demand because that need can be met with inventory.

**Figure 32 Cost Reductions in the Trucking Industry, 1977-1995**




Source: T. Lakshmanan and W. Anderson, "Transportation Infrastructure, Freight Services Sector and Economic Growth," February 2002, 3.

A review of the airline and trucking industries in the U.S. and the electric industry in the U.K. suggests that competition in electricity will lead to higher long-run capacity utilization and ultimately lower prices for customers. Deregulation in both airlines and trucking led to a dramatic improvement in capacity utilization for both industries. In fact, President Carter stated at the time of trucking deregulation that "regulation needlessly wastes our Nation's precious fuel by preventing carriers from making the most productive use of their equipment, and by requiring empty backhauls and circuitous routings."[113] More specific to electricity, the gradual deregulation of U.K. electricity over the course of the 1990s coincided with an improvement in capacity factor of about 10 percent, from an average of about 45 percent in the 1980s to between 50 and 55 percent since 2000.

2) Increased Customer Choice and Access

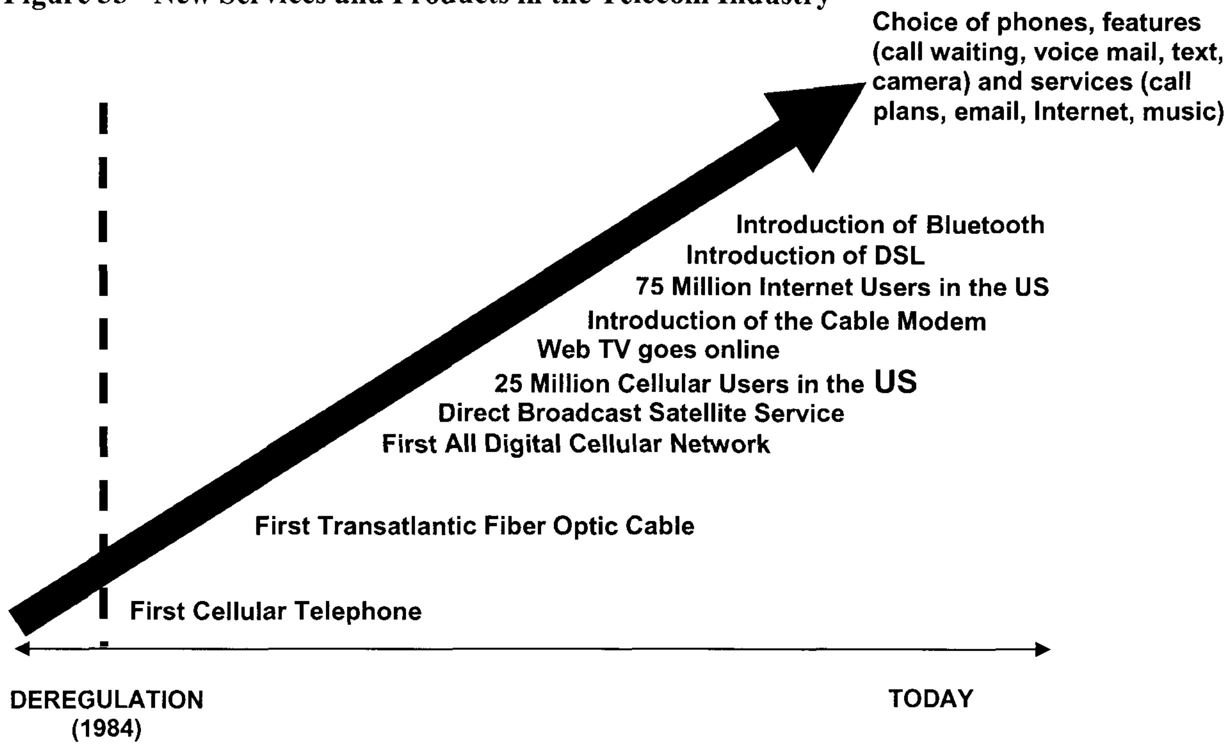
Competition in many industries has also led to increased customer choice and access to products and service. Regulation in telecoms, airlines, and trucking greatly restricted the degree to which firms could tailor their product, service, and price packages to different customers, and limited the ability of firms to reach customers for whom the regulated "one-size-fits-all" product was of limited value. In all three industries, deregulation led to an

[113] President Jimmy Carter, "Trucking Industry Deregulation Message to the Congress Transmitting Proposed Legislation," 21 June 1979.

explosion in the number and variety of product/price offerings as well as attempts to reach new customers not well served under the regulated model.

AT&T's breakup in 1984 and ensuing deregulation of the telecommunications industry has led to a broad range of new products and services as shown in Figure 33. Customers initially were presented with greatly increased variety in pricing and service packages from both local and long-distance carriers. Over time, competition led to the introduction of a wide selection of additional features and choices such as voice mail, call waiting, and mobile phones, all the way to today's integrated services and devices allowing voice, data, e-mail, and Internet, all through one device and service package.

**Figure 33 New Services and Products in the Telecom Industry**



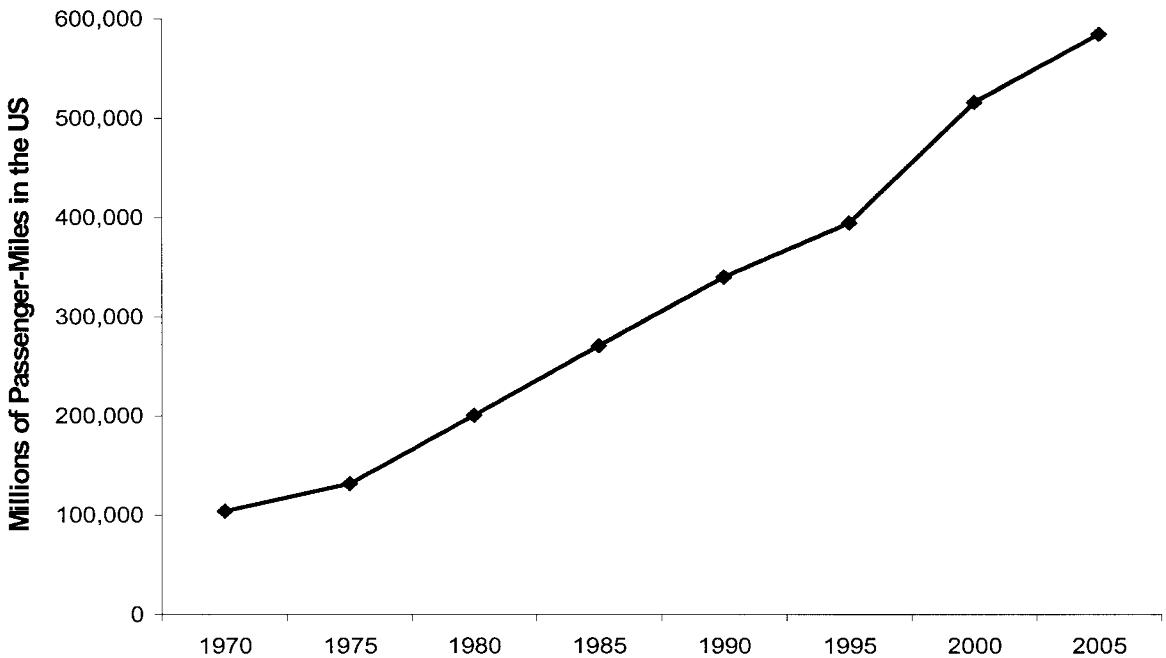

In the airline industry, competition led to more frequent service, increased routes, fewer connections, and an estimated 25 percent increase in the average number of airlines per route. For example, between 1979 and 1988 American Airlines and United Airlines increased the number of domestic airports it served from 50 to 173 and from 80 to 169, respectively.[114] Overall, the number of airlines certified for scheduled service with large aircraft has increased from 43 in 1978 to 139 by 2005.[115] Airlines developed marketing innovations to segment their customers with differentiated pricing and services. Virtually all airlines created customer loyalty programs, through which customers could accumulate "miles" to apply to

[114] Kahn, *Airline Deregulation*.

[115] "Airline Handbook Chapter 2: Economic Deregulation," 20 November 2007, Air Transport Association of America, Accessed 26 March 2008, http://www.airlines.org/products/AirlineHandbookCh2.htm.

future ticket purchases or other goods and services. Loyal frequent flyers also are rewarded with cabin upgrades, priority check-in, priority boarding, lounge access and other benefits. More recently, the industry has developed marketing partnerships tied to these programs to help promote other services such as credit cards, and in some cases, even electricity. Meanwhile, newly developed reservation and Internet services over the years have provided customers with greater access to flight and fare options. This increased access and product/service tailoring, accompanied by competition reductions in prices, greatly expanded the number of consumers utilizing air travel. Airline capacity grew significantly from 306 billion available seat miles in 1978 to 758 billion in 2005,[116] and as Figure 34 below shows, the number of total domestic revenue passenger-miles flown has more than tripled since deregulation in 1978 – from 188 to 584 billion revenue passenger miles.

**Figure 34 Increase in Air Travel, 1970-2005**




Source: US Government Accountability Office, "Airline Deregulation: Re-Regulating the Airline Industry Would Likely Reverse Consumer Benefits and Not Save Airline Pensions", June 2006, 10.

In the trucking industry, competition led to the simplification of highly complex regulated tariffs and increased competition on service quality. In 1975 (pre-deregulation), the Interstate Commerce Commission handled 340 complaints against truckers; in 1976, it handled 390 complaints. By 1980, after deregulation, this number had decreased to 23 cases.[117] The number and variety of companies exploded as regulatory barriers to entry were removed. In

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[116] Government Accountability Office (GAO), "Airline Deregulation: Regulating the Airline Industry Would Likely Reverse Consumer Benefits and Not Save Airline Pensions," Report to Congressional Committees, GAO-06-630, June 2006, 10.

[117] Thomas Gale Moore, *Trucking Deregulation,* 2002, The Concise Encyclopedia of Economics, 26 March 2008.

1975 only 18,000 trucking firms nationwide were authorized to provide service, compared with nearly 500,000 by 2000, with most firms specializing in a particular segment or product type.[118] With deregulation and improvements in technology, trucking and warehousing firms developed logistical services throughout the entire transportation process that enabled firms to manage all aspects of the movement of goods between producers and consumers. These changes led to value-added services to track packages, to maintain and retrieve computerized inventory information on the location, age, and quantity of goods available in order to better manage inventory, and to provide other customer services.

Meanwhile, retail electricity competition in the U.K. provides a glimpse of the potential for customer product/service tailoring in electricity. Small customers in the U.K. have seen greater choice in the number and variety of different supplier offers. As a result, the level of customer switching has grown steadily over the last eight years. According to a recent government report on residential retail markets, the incumbent Retail Energy Companies have lost nearly half of their customers to new suppliers.[119] In order to attract customers, suppliers are offering new products, such as fixed and capped price offers, online discounts, and supply from "green" resources. Such products now account for 20 percent of all electricity and gas accounts.[120] In addition, some suppliers are beginning to offer new services, such as free energy surveys and discounted energy efficient appliances along with their regular products. A 2005 survey of customer experiences in the U.K. retail market indicated that 97 percent of customers were aware that they could switch suppliers, 47 percent had switched suppliers at some point, and 85 percent were satisfied or very satisfied with their current supplier.[121] A review of currently available offers for residential customers in urban areas suggests that customers typically can choose from between 40 to over 50 distinct offers from 8 to 12 suppliers.[122]

3) Technological Innovation

Competition provides incentives for firms to innovate and improve technology. Most regulated companies are unable to retain much, if any, of the economic value of the innovations or technological developments they may introduce. While this may seem like a good deal for consumers, it tends to slow technological progress by dampening the incentive of regulated companies to innovate. Therefore, in the long-run, customers lose.

Deregulation in most industries has been accompanied by significant improvements in technology. In the airline industry, new technology was developed to attract and retain customers and improve financial performance. For example, two airline companies,

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[118] U.S. Department of Transportation, Bureau of Transportation Statistics, _The Changing Face of Transportation – Chapter 2: Growth, Deregulation, and Intermodalism_, (Washington DC: 2000), 2-40.

[119] Office of Gas and Electricity Markets (OFGEM), _Domestic Retail Market Report – June 2007_, Ref. No. 169/07, 4 July 2007, 23.

[120] OFGEM, _Domestic Retail Market Report – June 2007_.

[121] U.K. Office of Gas and Electric Markets, _Domestic Retail Market Report - June 2005_, Ref. No. 24b/06, 7 February 2006, Detailed Appendix Tables 1 and 3 and Figure 3.

[122] TheEnergyShop.com, 2006, Energy Services Online Limited, Accessed 27 March, 2008, www.theEnergyShop.com.

American and United, developed sophisticated computerized reservation services to better offer services and segment customers. These reservation systems allowed airlines and travel agents to track fare and service changes more efficiently for hundreds of millions of passengers. Over time, these reservation systems increased in functionality and were divested from airlines as separate independent businesses. Today, this technology has evolved, making it possible for individual travelers to book reservations, purchase hotel rooms, rent cars, and arrange other travel services online.

Furthermore, the incentive to reduce costs brought on by competition led airlines to demand a greater focus on fuel economy and operating economics in aircraft design from the airline manufacturers. The most recent Airbus and Boeing aircraft are around 35 percent more fuel efficient than late 1970s vintage designs.[123] The improved sensitivity to customer demands brought on by competition led to the development of regional jets, a technology that was not used in the United States until 1993, but proved highly successful in bringing jet travel to previously underserved routes and timeslots. To further reduce costs and expand services, airlines developed code-sharing agreements that allowed two or more airlines to offer a broader array of services to their customers than they could individually. These marketing arrangements enabled airlines to expand service at a reduced cost by allowing them to issue tickets on a flight operated by another airline as if it were its own. These programs typically link marketing and frequent flyer programs and facilitate convenient connections between the code-sharing partners. In addition to code sharing, several groups of airlines have formed global alliances that compete against each other for international passengers, whereby participating airlines benefit from expanded networks and reduced costs through the sharing of staff, facilities, and sales offices.[124]

The telecommunications industry offers a similar example of significant innovation unlocked by technology. Similar to electricity, most of the early groundbreaking innovation that established the industry took place in the late 19th and early 20th century, prior to any form of deregulation. From the point when the Federal Communications Commission was created in 1934 to oversee interstate telephone service through to deregulation in the early 1980s, innovation in the industry slowed. While direct-dialing, touch-tone phones and pagers were all developed and adopted during this period, other innovations from the time, such as communications satellites and mobile-phone technology were not significantly adopted until after deregulation. In the twenty-odd years since deregulation, however, the industry has experienced an explosion of groundbreaking innovations, including, among others, fiber optic cables, computer switching equipment, and wireless data/internet services.

Competition has also driven innovation in the trucking industry. Examples of new technologies that have been introduced since the advent of deregulation in 1980 include electronic data interchange, new vehicle location detection systems, voice and data communication services, and just-in-time delivery services.[125] In addition, because trucking companies are no longer bound to deliver goods along pre-specified routes, as was the case

[123] P.M. Peeters, J. Middel, and A. Hoolhorst, National Aerospace Laboratory NLR, "Fuel Efficiency of Commercial Aircraft: An Overview of Historical and Future Trends," Report No. NLR-CR-2005-669, 12.

[124] Air Transport Association, http://www.airlines.org/products/AirlineHandbookCh2.htm.

[125] Cynthia Engel, "Competition Drives the Trucking Industry," Monthly Labor Review, April 1998, 39.

under regulation, they continually seek to optimize routes. Consequently, there has been a surge of services over the last 20 years that provide sophisticated dispatch management. These optimization and dispatch services provide fuel savings by reducing empty miles and increase truck utilization.[126]

4) Elimination of Cross-Subsidies

In many industries, the transition to competition eliminated cross-subsidies that distorted consumption and customer decision-making. Regulatory restrictions on pricing and product structure led to some groups of customers receiving higher or lower prices than they would under competition, encouraging inefficient over- or under-consumption. For example, in the telecommunications industry, regulated rates did not reflect the cost for each service offered. Rates were broad averages designed to recover total revenue requirements across all services. Embedded in this structure were numerous cross-subsidies among different customer groups: long-distance customers subsidized local service while large customers subsidized small and individual customers. Deregulation of the telecommunications industry resulted in elimination of these cross-subsidies as competing suppliers unbundled these two services and priced each individually based on their separate cost structures and value to consumers.

Similar subsidies existed in the regulated airline industry due to regulatory restrictions on pricing and routing. Routes with high density (many travelers), and thus more favorable cost structures, generally subsidized higher-cost routes with low density in more rural areas. These subsidies eroded as markets became competitive and suppliers were able to price different routes individually based on their unique economics.

Competition can be expected to reduce similar subsidies in the electric industry as competitive suppliers develop tailored pricing for a variety of customer services and consumption patterns.

5) Lower Prices

Ultimately, industry deregulation and the introduction of competition have resulted in lower prices for consumers. Figure 35 shows real prices as they have evolved in the airline, trucking, and telecommunications industries indexed to the years immediately around deregulation. All three industries saw sustained price reductions beginning with deregulation and continuing to the present in most cases, with airline[127] and telecoms customers realizing real price reductions of close to 40 percent since deregulation. These price reductions are the consequence of increased competition from a larger group of competitors, improved incentives to drive down costs, and better utilization of resources.

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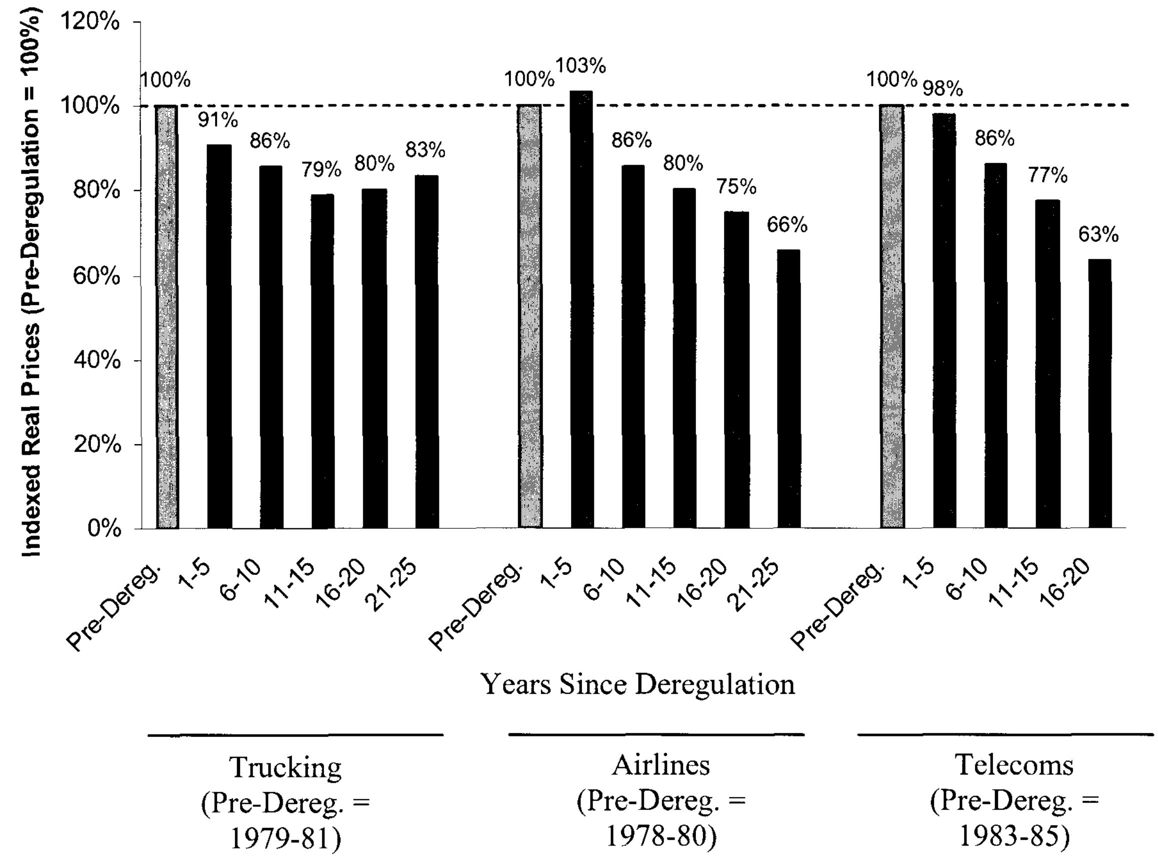
[126] Steven Strong, "Optimization Leads Quiet Revolution in Trucking," SupplyChainBrain.com, Global Logistics and Supply Chain Strategies, June 2001.

[127] A June 2006 report by the GAO concluded that "reregulation of airline entry and rates would not benefit consumers and the airline industry. Although some aspects of customer service might improve, reregulation would likely reverse many of the gains made by consumers, especially lower fares." (GAO, Airline Deregulation, 36.)

**Figure 35 Post-deregulation Prices for the Trucking, Airline, and Telecommunications Industry**




Source: Based on the U.S. Bureau of Economic Analysis Gross Domestic Product and Chained Price Indices by Industry, 1977-2006. See http://www.bea.gov/industry/gdpbyind_data.htm. Nominal prices are deflated using the GDP deflator.

As Figure 35 shows, the initial years after deregulation were not always marked by significant price declines, and certainly other external factors such as changes in input costs (e.g., fuel costs) or non-related changes in technology may affect overall price levels from one period to the next. However, as competition drove costs out of the system and the industry adjusted, sustained deep price declines were the norm in trucking, airlines, and telecoms. Given that competition in electricity has been a far less complete transition than these other industries and that electric generation construction and fuel costs have increased significantly in recent years, it is not surprising that the price benefits for electric consumers in the United States are harder to discern. Nonetheless, our expectation is that a competitive electricity market will show similar benefits over the long-term, provided competition is allowed to continue to develop.

## V. Competition Will Provide a Better Path to Confront the Enormous Challenges Ahead

The experience of the 1970s and 1980s in the electric industry suggest that regulation is not well-equipped to navigate the industry's future challenges of the rising global cost of energy and environmental requirements. The more recent experience of the electric industry and those of other industries suggest, however, that competitive markets will provide a better path to confront the enormous challenges ahead.

### A. Re-Regulation Will Not Fix the Perceived Problems

In response to the perceived problems associated with competition, some states are moving back toward regulation.[128] Some of this backpedaling, like re-regulation bills, is very direct. Other actions are more subtle: there are new efforts to pick the "right" generation technologies, to mix cost-of-service and market-based new construction, to establish "vintage pricing" with special higher pricing for new builds, and to rely on rate-funded, customer-guaranteed long-term contracts using an integrated resource planning process in an effort to stimulate new capital investment. All of these actions are forms of re-regulation that are not only intended to "fix" competitive pricing issues but also ensure that "enough" investment in new generation is made on a timely basis. Proponents of these initiatives argue that they are necessary to ensure adequate reliability, environmental compliance, fuel diversity, and even national security.

Some policymakers likely will try to characterize these efforts as a new, better form of regulation or a mix between regulation and competition. But these actions are nothing more than a return to the central planning of the past – the same central planning that tried to select the right amount and the right mix of technologies in the 1970s and failed. There is no reason to believe that this "new" least-cost planning approach will be more successful today. The inherent flaws, especially the underestimation and misallocation of risks, are still present. And, as before, customers will become responsible for inefficient choices and significant risks inherent in future electricity markets. Re-entry of regulated utilities into the generation business, whether through direct utility ownership or allowing utilities to enter into long-term contracts with new generators, is risky for customers. Either action is a centrally planned, ratepayer-funded approach to new generation that transfers risk from the developer and utility to the retail customer. Long-term contracts and/or investments increase the risk that costs will be above market, potentially for significant periods of time.

Further, re-entry of utilities into the generation business is incompatible with wholesale competition and will deter – and perhaps even eliminate – market-based entry of new generation. It is not likely that rate based investments could co-exist with competitive generation. The different risk profiles of rate-funded investments, compared to competitive investments, lead to more and earlier building under the regulated model. This occurs because investment decision rules for rate-funded new generation are less stringent than those for competitive generation – there is a lower investment "hurdle" for rate-funded

[128] These efforts are particularly being made in states which made little effort to have retail competition at the residential level.

commitments than for competitive investment because the risks are shifted from the investor in generation to retail customers.[129] As a result, under most circumstances, a project will appear economic on a rate-funded basis before it would appear economic on a market-funded basis. So, under the utility procurement model, new rate-funded commitments will be made before new market commitments. Once these rate funded commitments are made, they serve to depress the visible forward price signals, and resulting market price expectations will be inadequate to bring forth investment on a competitive basis. Hence, the continuation of cost-of-service rate-making for generation – either with utility-owned generation or long-term contracts guaranteed by ratepayers – is a barrier to the emergence of a competitive market model. Therefore, both immediate re-regulation and gradual re-entry of regulated utilities into the generation business are likely to end up in the same place – that is, a *de facto* return to the regulatory decision-making of the 1970s that relied on a sluggish, administrative, command-and-control process to solve inherently risky resource allocation problems.

### B. A Competitive Market Should Remain the Desired End State

Relying on markets to make investment decisions, rather than on central planning backed by ratepayer guarantees, is sound public policy. The industry must tackle an ongoing need for new generation investment to serve growing load, to replace its aging power plant fleet, and to achieve ambitious environmental objectives. Reliance on a well-structured competitive market model, in which end-use customers receive efficient price signals and do not assume long-term investment risks, and investors and market intermediaries actively manage such risks, will serve customers better in the long run.

Although relying on competitive markets is preferable to the traditional regulatory model, there is still a need for safeguards and regulatory oversight. In order for market-based pricing to result in an efficient and effective outcome, generation markets must be "workably" competitive. A well-structured competitive market model should include wholesale and retail competition, central energy markets using locational prices, non-discriminatory open-access transmission, and new generation built without utility long-term contracts or regulatory guarantees funded by ratepayers. In order to ensure non-discriminatory open access of the transmission system and to ensure that companies cannot exercise market power, regulators and/or system operators must monitor market activities to ensure a fair and level playing field. As competitive generation markets develop, federal and state actions have already been taken and continue to be improved upon to monitor electricity markets. These safeguards include: federal oversight of non-profit RTOs to ensure non-discriminatory open-access of the transmission system, state and federal oversight of market power and concentration (mergers, market price manipulation, etc.), state

[129] Rate-funded projects typically evaluate, on a present value basis, the projected production cost savings from the project over its assumed operating life to the incremental capital or demand charge payment required. The discount rate used in this evaluation usually reflects the utility's cost of capital, which is typically lower than that used by a competitive developer. Competitive project evaluation incorporates a higher discount rate, or hurdle rate, and often a shorter payback period requirement, in recognition of the uncertainty of future market prices. While it may appear that the lower utility hurdle rate results in lower cost to consumers, this is not the case when the continued risks that consumers bear under that model are taken into consideration. A regulatory guarantee does not eliminate any of the risks associated with the generation asset; it merely shifts the risks from the investor to ratepayers.

certification/licensing of retail suppliers (e.g., rules governing communication and marketing practices, supplier credit requirements, state oversight of consumer protections and services including education, disconnection, low-income assistance, etc.), federal oversight of wholesale trade accounting, federal and state safety standards, federal and state environmental emission requirements, and so forth. These oversight and monitoring functions will likely be necessary for the foreseeable future and should not be ignored. Meanwhile, incidents of market abuses in relatively young markets should not be used as an excuse to return to the mistakes of the past. Nor should the unfavorable and unforeseen outcomes of certain negotiated transition plans or settlements that were used to "unwind" the regulatory past be relied upon to demonstrate the failure of competitive markets. Unfavorable and unforeseen outcomes are likely to occur in electricity markets that are inherently risky and mistakes will be made whether there is competition or regulation. Key questions for policymakers are who should pay for those mistakes – investors who make the decisions or ratepayers who have to live with the consequences of central planning – and which model is likely to respond more quickly to ever-changing market conditions. The authors of this paper believe that competitive markets allocate these risks more efficiently, and that the benefits of competition can be achieved while continuing to maintain or even enhance funding for public policy programs, such as low-income assistance, energy efficiency, and customer education.

We also believe that retail competition, if given a chance to develop, is likely to play a bigger role in the future and can reinforce competitive wholesale markets with market pricing and customer response. Many larger customers face market prices and have already switched to competitive suppliers. Utilities also need to establish retail prices at market levels for smaller customers still on default service, so that these customers can see the "true costs" (including environmental costs) of their consumption decisions. This transparency will become increasingly necessary as we strive to meet the challenges of climate change. Over time, competitive suppliers will be able to extend the benefits of value-added services to smaller customers, especially if improvements are made in market design, metering, communications, computer, and energy control technologies.

### C. Embrace Electric Competition or It's Déjà Vu All Over Again

It has been said that those who cannot learn from history are doomed to repeat it.[130] Many states that have embarked on electric industry restructuring are at a turning point – trying to decide whether to go back to a regulatory model or move forward with restructuring. As Paul Joskow concluded:

> ...the jury is still out on whether policymakers have the will to implement the necessary reforms effectively...Creating competitive wholesale markets that function well is a significant technical challenge and requires significant changes in industry structure and supporting institutional and regulatory governance arrangements. It requires a commitment by policymakers to do what is necessary to make it work...the revisionist history about the 'good

[130] Based on quote by George Santayana, a Spanish-born American author and philosopher. (*The Life of Reason, Vol. 1, Reason in Common Sense*, New York: Charles Scribner & Sons, 1905, 284.)

> old days of regulation' has conveniently ignored the $5,000/MW nuclear power plants, the 12 cents/kWh PURPA contracts, the wide variations across utilities in the construction costs and performance of their fossil plants, and the cross-subsidies buried in regulated tariffs that characterized the regulatory regimes in many states. As we look at the costs and benefits of competition we should not forget the many costly problems that arose under regulation.[131]

Either policymakers will take steps to facilitate competitive markets or they may find themselves – consciously or not – back in the 1970s. Under the latter scenario, we will be entrenched in a regulated model that requires utilities and regulators to make billions of dollars of resource choices in a centrally-planned manner supported by ratepayer money, while confronted with tremendous uncertainty about technology, carbon control, fuel prices and demand levels. Poised now at a point where generation supply must accommodate higher natural gas prices on the one hand and the need for carbon control on the other, it is critical to rely on the market to make choices about fuel type and technology for new investments and actively manage the associated risks. We do not need another round of regulated investments that later prove to be uneconomic and cost consumers billions of dollars.

The goal of policy changes should not be to attempt to reverse the impacts of the increased costs of producing electricity, but rather to focus on ways to improve future investment, operating and consumption decisions – that is, to increase efficiency and provide customers with a greater choice of products and services. This ultimately will produce lower costs for consumers. In order to achieve these efficiency benefits, the electricity industry should not repeat the mistakes of the past, but should instead embrace competition.

[131] Joskow, "Markets for Power in the United States: An Interim Assessment," 32-33.