Putting Competitive Power Markets to the Test

The Benefits of Competition in America's Electric Grid: Cost Savings and Operating Efficiencies

JULY 2005

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Global Energy Decisions

Putting Competitive Power Markets to the Test

Global Energy independently assessed the benefits of wholesale electric market competition, with the following findings:

1. **Consumers realized $15.1 billion in value from wholesale electric competition in the 1999-2003 study period**. Global Energy calculated the benefits of wholesale competition for the Eastern Interconnection as they occurred. Those results were compared with a simulation of market conditions without the changes in market rules that enabled wholesale competition. Global Energy used its generally available Strategic Planning™ software to replicate the market rules and conditions and calculate consumer benefits. Consumers benefited if the study showed a positive difference between current market conditions and the simulation of the traditional market rules prior to wholesale competition. The results of the analysis are that wholesale customers in the Eastern Interconnection have realized a $15.1 billion benefit due to electricity competition.

2. **Competition dramatically improved the operating efficiency of power plants.** Global Energy conducted an analysis and review of the North American generation fleet operations to assess improvements and efficiencies attributable to competitive forces. This analysis was based on a study period of 1999-2004. Global Energy uncovered strong evidence indicating the electric utility industry has improved its operations and efficiencies, largely due to competitive forces. Some of the power plants with great gains in efficiency had been auctioned off by their prior owners and had historically been relatively poor performers. But the skill of experienced fleet operators, the standardization of procedures and maintenance, and the combined buying power for fuel, equipment, and supplies have produced dramatic improvements in capacity factors and plant performance. The cost savings and energy efficiency resulting from reduced refueling outages, improved capacity factors, and reliability are continuing to provide substantial benefits to consumers.

3. **Opening the PJM Interconnection to more electric supply competitors produced $85.4 million in annualized production cost savings during 2004 for wholesale power customers.** The benefits of expanding the PJM wholesale power market with the addition of Commonwealth Edison (ComEd), American Electric Power (AEP), and Dayton Power & Light (DPL) in 2004, produced $85.4 million in annualized production cost savings for Eastern Interconnection customers. The expansion reduced transmission seams and provided for the entry of new competitors in the Midwest, resulting in a more efficient regional power market. The study showed that PJM wholesale customers weren't the only ones to benefit; rather, wholesale customers throughout the Eastern Interconnection realized a savings. These annual production cost savings should continue year after year.

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The Benefits of Competition in America's Electric Grid: Cost Savings and Operating Efficiencies

Introduction

The competitive policies adopted by Congress and implemented by FERC are unequivocally producing consumer benefits.

- Electricity customers in America's Eastern Interconnection power markets saved more than $15.1 billion in energy costs from 1999 to 2003 as a result of competition in wholesale power markets.
- Overall industry improvements in nuclear power plant operations produced enough additional energy to power more than 10 million residential households for one year.[1] Comparable operating efficiency improvements occurred in power plants fueled by coal, which created enough additional energy to power more than 25 million residential households.
- The benefits of expanding the PJM wholesale power market in 2004 provided $85.4 million in annualized production cost savings for Eastern Interconnection wholesale customers through the reduction of transmission seams and entry of new competitors.

Global Energy was asked by a prominent group of electric power generators, marketers, and suppliers to perform an independent analysis of wholesale competition at work today to identify and quantify the existing and foreseeable consumer benefits of competitive electricity markets.[2] This report, titled *Putting Competitive Power Markets to the Test*, is the result of that independent analysis.

Congress created the legislative framework that enabled competitive power markets to meet the nation's growing energy needs. The Public Utility Regulatory Policies Act of 1978 (PURPA) opened the door for competitive power markets with requirements that utilities buy energy from qualifying cogeneration and renewable resource facilities. PURPA demonstrated that power plants could be developed, financed, built, and operated independently of the traditional utility's rate base. Congress expanded wholesale competition in the Energy Policy Act of 1992 (EPAct), creating an entire new class of "exempt wholesale generators" (EWGs) that had more contractual and regulatory flexibility than those under PURPA. The EWGs were authorized to build and operate power plants supported by sales into competitive energy markets, rather than relying upon traditional cost-of-service rate base returns to finance power plant construction. Indeed, the motivation behind these changes was to shift the risk of future power plant construction costs from utility ratepayers to investors in these projects. Ultimately, they became known as "merchant" power plants.

Competitive power markets have flourished by allowing energy companies to make sales using market-based rates (MBR) instead of traditional tariff rates, as allowed by the Federal Power Act (FPA). FERC's implementation of open access and MBR led the initiative to create wholesale power markets that ensured just and reasonable wholesale rates.

FERC has been progressively using its FPA authority to implement and foster wholesale power market competition through a series of orders and market initiatives. FERC's push to establish Regional Transmission Organizations (RTOs) and organized spot markets in order to ensure nondiscriminatory

[1] Based upon average residential customer annual usage of 10,803 kWh per year.
[2] The sponsors of this Global Energy analysis are: BP Energy Company, Constellation Energy, Exelon Corporation, Mirant Corporation, NRG Energy, Inc., PSEG, Reliant Energy Inc., Shell Trading Gas and Power Company, Williams, and Suez Energy North America. The Electric Power Supply Association served as project manager on behalf of the sponsors.

transmission and market access has met with fierce resistance in some parts of the country, namely the Southeast and the Pacific Northwest. Despite that resistance, RTO membership continues to grow. The PJM RTO, which serves the Mid-Atlantic and some Midwestern states, has seen rapid expansion, is integrating its energy markets with those of the Midwest Independent System Operator (ISO), and is collaborating with NYISO and ISO-NE to create a large and growing seamless wholesale power market. The Midwest ISO itself successfully launched its formal market operations on April 1, 2005. Further growth continues to occur with the formation of the Grid West independent transmission organization. Thus far, it has 87 members, has adopted developmental bylaws, and is seating a developmental board of directors.

The growth in the PJM RTO is one aspect Global Energy evaluated for this study because it enables a comparison of consumer benefits in organized RTO markets with traditional markets that do not have the market access afforded by RTOs.

Regional power markets, especially those organized under RTOs now have a proven track record over eight years. However, discussions about the cost and benefits of RTO formation continue among key market participants and regulatory authorities. This study can be viewed as a contributor to that discussion.

Study results show wholesale competition in America's electric power markets is working. When the subject of competition in the electric power industry is discussed in public, often the report card on how competition has performed is told in the context of the California energy crisis or the problems of Enron. No credible study of wholesale competition can be done without recognizing this "elephant in the room." However, the real standard by which competition should be measured encompasses all economic and non-economic factors (e.g., operating efficiencies). Further, the economic comparison should measure today's market prices against the regulated prices that would have occurred, absent any competitive initiatives. Now, 13 years after Congress passed EPAct, it is time to look at how wholesale competition in the electric generation sector of the industry is doing—and whether electricity customers are benefiting from the wholesale competition that the 1992 EPAct envisioned.

The results of Global Energy's analysis of the Eastern Interconnection (an area that comprises two-thirds of the U.S. population and electricity demand, three-quarters of the nation's electricity control areas, and eight of the ten North American Electric Reliability Council's regional councils) are that wholesale competition is working as Congress intended. The FERC regulations and decisions in fostering the creation of regional transmission markets are working to create effective competitive energy markets. Customers are realizing the benefits of wholesale competition in the form of lower wholesale costs for their electric suppliers, more options from renewable resources, better opportunities to manage risk and wider competition from more market participants.

How the Study was performed by Global Energy. The study was conducted by Global Energy using its Global Energy Reference Case, an independent, transparent analysis of electric and natural gas market supply and demand fundamentals updated twice yearly and used widely by credit rating agencies, investment banks, energy companies, utilities and the engineers, consultants and attorneys who serve them. Global Energy used its own independent data sources and market leading **EnerPrise™ Strategic Planning** *powered by MIDAS Gold®* software to perform the analysis. The modeling methodologies and approach are consistent with Global Energy's consulting best practice for cost benefit studies. While the sponsors of the study were involved in helping Global Energy define an appropriate work scope for the project, the assumptions, data, analysis, and conclusions outlined in this report are Global Energy's alone and do not necessarily represent the views of the sponsors.

Consumer Value of Competition

To assess whether wholesale competition is working as Congress and FERC intended, Global Energy assessed the Eastern Interconnection wholesale electric power markets as they occurred in the 1999-2003 study period ("With Wholesale Competition" case). Those results were compared with a simulation, which excluded the regulatory changes, tariff protocols, and market rules that enabled wholesale competition ("Without Wholesale Competition" case).

Global Energy's With Wholesale Competition case divided the Eastern Interconnection into two distinct business sectors. The "Regulated" sector comprised traditional regulated utilities, which have an obligation to serve native load retail customers. The "Competitive" sector comprised the exempt wholesale or merchant generating units, which are at risk, as they are not allowed a regulated return. In this analysis, the sole source of income for the Competitive sector is energy and capacity sales to the Regulated sector.

The Without Wholesale Competition case calculated the consumer cost had the market remained as traditional, vertically integrated utilities operating in a regulated environment without wholesale competition. Global Energy used its generally available Strategic Planning software to replicate the market rules and conditions and to calculate the customer benefits. Customers benefited if the study showed a positive difference (lower costs) between current market conditions and the simulation of the traditional utility market prior to wholesale competition. The results of the analysis are that consumers in the Eastern Interconnection have realized a $15.1 billion benefit due to wholesale competition over what they would have realized under the traditional regulated utility environment.

The valuation method Global Energy employed in the analysis is the minimization of operating expenses for the regulated utility buyer. Under traditional utility cost of service regulation, the minimization of operating expenses provides the greatest benefit to the retail customer. Global Energy assumed all operating expenses were fully recovered in the base revenues of the regulated utility sector. The operating expenses include fuel expenses, energy and capacity purchases from the Competitive market sector, variable O&M, fixed O&M, depreciation, taxes, and operating income.[3]

[3] For the Regulated Sector, Operating Income is defined as rate base times a "fair and reasonable" allowed return on rate base of 8.5 percent.

Figure RS-1 illustrates the Regulated sector's additional operating expenses for the Without Wholesale Competition case. Figure RS-2 illustrates the Regulated sector purchasing energy and capacity from the Competitive sector for the With Wholesale Competition case. In both cases, Global Energy calculated the Regulated sector's fuel and variable O&M expense for serving the Eastern Interconnection load as these expenses change between the two cases.

Figure RS-1
Without Wholesale Competition

Regulated Sector

Operating Expenses

Fuel

+ Variable O&M

+ Fixed O&M

+ Depreciation

+ Property Taxes

+ Income Taxes

+ Operating Income

New Generation Built by Regulated Sector

Figure RS-2
With Wholesale Competition

Regulated Sector

Operating Expenses

Fuel

+ Variable O&M

+ Energy Purchases

+ Capacity Purchases

Competitive Sector Revenues

SOURCE: Global Energy.

Defining the Two Cases

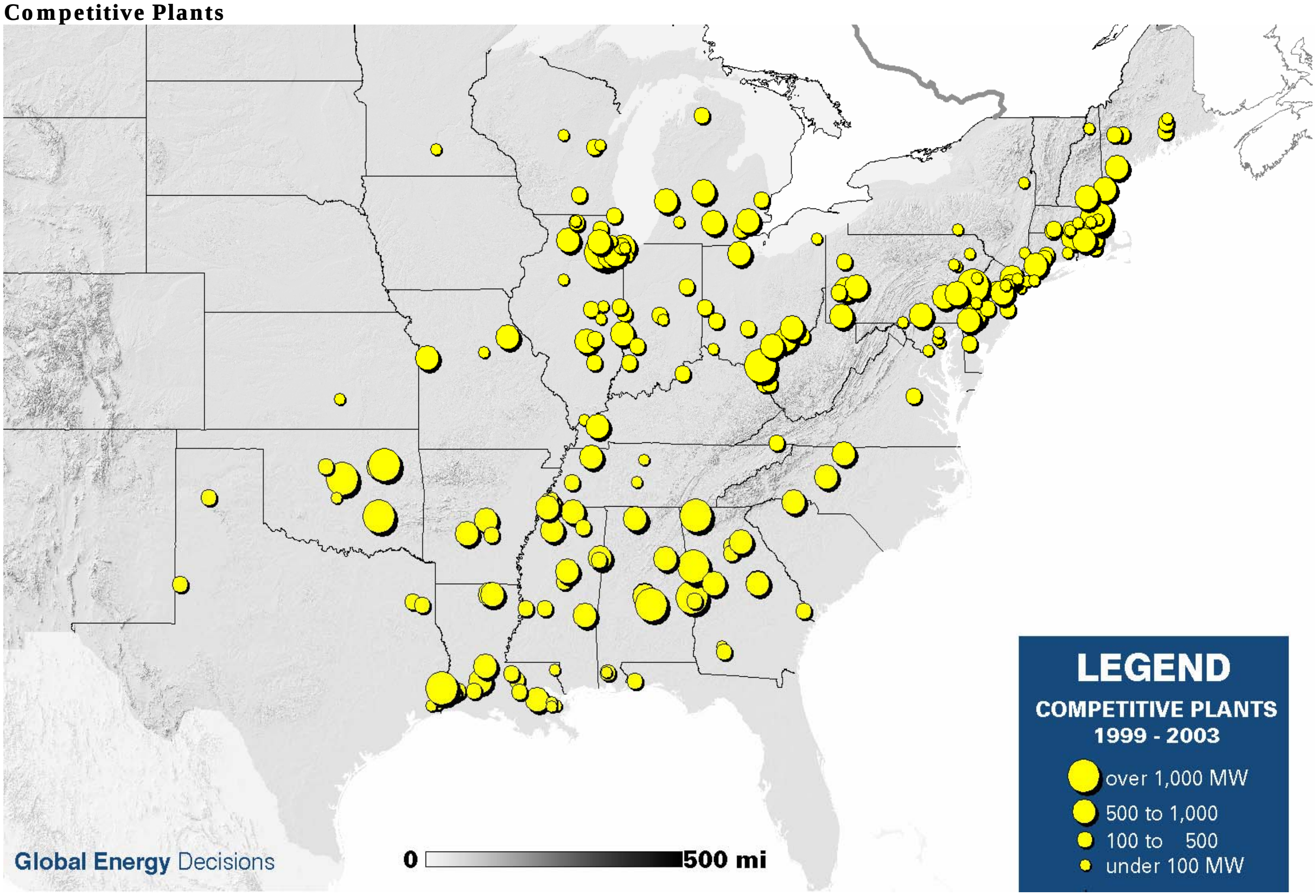
The With Wholesale Competition case differs from the Without Wholesale Competition case in three main areas.

1. Competitive Plants
   - In the Without Wholesale Competition case, it is assumed that no competitive or merchant plants would have been built; however, qualifying facilities built pursuant to PURPA requirements were included.
2. Regional Transmission Organization (RTO)
   - In the Without Wholesale Competition case, it is assumed that FERC Orders 888 and 2000 never occurred and that RTOs were not formed. RTO transmission rates are replaced with pancaked transmission rates, which traditionally existed in these areas.
3. Market-Based Rates for Wholesale Energy
   - In the Without Wholesale Competition case, it is assumed that marginal cost-based contracts replace market-based wholesale energy.

Competitive Power Plant Development (With Wholesale Competition Case)

The Competitive sector comprises 88,686 MW of generation added over the five-year study period. The mix of generation is 56 percent combined cycle units (50,106 MW) and 44 percent simple cycle units (38,580 MW). For this analysis, Global Energy estimates that the Competitive sector sold $13.7 billion worth of energy and capacity to the Regulated sector. Figure RS-3 shows the dispersion of competitive plants added in the Eastern Interconnection during the study period.

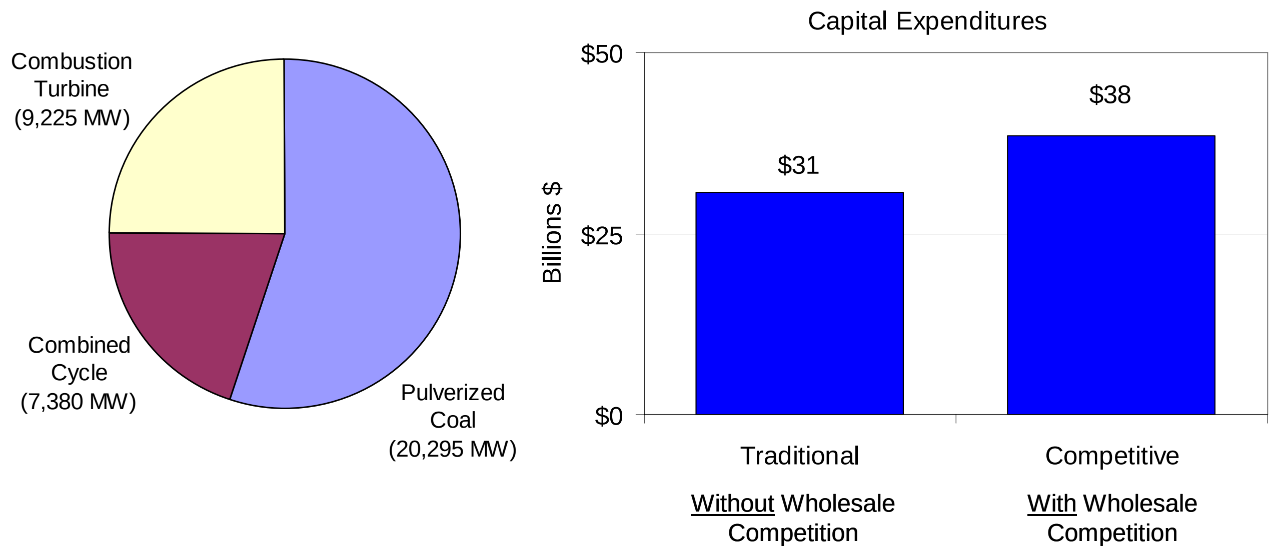
Figure RS-3
Competitive Plants



Traditional Power Plant Development (Without Wholesale Competition Case)

In the Without Wholesale Competition case, Global Energy calculated the level and mix of new generation that utilities would have built to satisfy minimum reserve margins and consumer energy requirements. That electric supply portfolio would have consisted of 55 percent pulverized coal, 20 percent combined cycle, and 25 percent combustion turbines. As shown in Figure RS-4, capital spent by the Regulated sector is $7 billion less than was spent by the Competitive sector.

Figure RS-4
Traditional Generation Supply Portfolio; 1999-2003



SOURCE: Global Energy.

Comparing the Two Cases

The five-year consumer benefit of the With Wholesale Competition case versus the Without Wholesale Competition case was $15.1 billion. A comparative expense breakdown is shown in Table RS-1.

Table RS-1
Consumer Benefit; 1999-2003: Cost of Service Environment vs. Competitive Market

	Without Wholesale Competition	With Wholesale Competition	Consumer Benefit
Fuel (Fossil and Nuclear)	160,979	156,971	4,008
+ Variable O&M	21,902	19,515	2,387
+ Competitive Energy Purchase	-	11,495	(11,495)
+ Competitive Capacity Value	-	2,220	(2,220)
+ Fixed O&M	7,610	-	7,610
+ Depreciation	2,670	-	2,670
+ Property Taxes	931	-	931
+ Income Taxes	3,289	-	3,289
+ Operating Income	7,960	-	7,960
Operating Expenses (millions $)	**205,341**	**190,201**	**15,140**

SOURCE: Global Energy.

The With Wholesale Competition case does not reflect expenses and returns associated with existing utility infrastructure. The Without Wholesale Competition case includes expenses and returns for new generation constructed by the Regulated sector. In essence, Global Energy is quantifying the cost and risk transfer of power plant construction between the two sectors (Competitive and Regulated). Table RS-2 provides a description of each variable of the operating statement.

Table RS-2
Operating Statement Variable Descriptions

	Without Wholesale Competition	With Wholesale Competition
Fuel (Fossil and Nuclear)	Cost of fossil and nuclear fuel burned by existing utility infrastructure. This line item includes all plants (regardless of ownership) built prior to 1999, new rate base plants built in the 1999-2003 study period, and the 36,900 MW of traditional plants identified in Figure RS-4.	Cost of fossil and nuclear fuel burned by existing utility infrastructure. This line item includes all plants (regardless of ownership) built prior to 1999, plus new rate base plants built in the 1999-2003 study period. The 88,686 MW of competitive plants identified in Figure RS-3 are excluded from this line item.
Variable O&M	This line item includes all plants (regardless of ownership) built prior to 1999, new rate base plants built in the 1999-2003 study period, and the 36,900 MW of traditional plants identified in Figure RS-4.	This line item includes all plants (regardless of ownership) built prior to 1999, plus new rate base plants built in the 1999-2003 study period. The 88,686 MW of competitive plants identified in Figure RS-3 are excluded from this line item.
Competitive Energy Purchase	Not applicable. In this case there are no competitive plants.	Cost of energy purchased from the competitive plants identified in Figure RS-3.
Competitive Capacity Value		Cost of capacity purchased from the competitive plants identified in Figure RS-3.
Fixed O&M	These expenses are associated with the 36,900 MW of traditional plants constructed in the study period.	Expenses were not included for existing utility infrastructure because it would be the same for with and without cases.
Depreciation		
Property Taxes		
Income Taxes		
Operating Income	This line item is the operating income of the 36,900 MW of traditional plants constructed in the study period. The operating income is calculated as rate base times a return on rate base of 8.5 percent.	Operating income was not included for existing utility infrastructure because it would be the same for with and without cases.

SOURCE: Global Energy.

Summary - Consumer Value of Competition

Electricity customers in the Eastern Interconnection benefited by more than $15.1 billion over the five-year study period, in contrast to what they would have been expected to pay under more traditional regulated markets without wholesale competition. Had competitive generators and power suppliers not emerged, regulated utilities would have been required to build rate base generating assets and incur the costs to run them. Under wholesale competition, competitive energy suppliers take the risk of building and operating the power plants and selling the energy output to utility and other wholesale or large industrial customers.

These regulated utilities paid the competitive merchant sector more than $13.7 billion for the energy and capacity in the study period. However, in the Without Wholesale Competition alternative, there would have been an additional $28.9 billion in operating expenses. Thus, the consumer benefit is $15.1 billion when all the costs, including the cost to buy merchant power, were considered over the more traditional process of allowing utilities to build the assets and incur the increased cost of fuel, O&M, depreciation, taxes, and operating income to run them.

Wholesale Market Competition Dramatically Improved the Efficiency of Power Plants

Global Energy Decisions conducted an analysis and review of the North American generation fleet operations to assess improvements and efficiencies attributable to competitive forces. This analysis was based on a study period of 1999-2004. Global Energy uncovered strong evidence indicating the electric utility industry has improved its operations and efficiencies, largely due to competitive forces. Some of the power plants with great gains in efficiency had been auctioned off by their prior owners as relatively poor performers. But the skill of experienced fleet operators, the standardization of procedures and maintenance, and the combined buying power for fuel, equipment and supplies have produced dramatic improvements in capacity factors and plant performance. The cost savings and energy efficiency resulting from reduced refueling outages, improved load factors and reliability continues to substantially benefit consumers.

The analysis focused on the nuclear and coal-powered generating units for traditional and competitive operators. Traditional operators are best defined as investor-owned utilities, municipalities, and cooperatives that are subject to retail rate regulation. Competitive operators are best defined as independent power producers and other generators that are not subject to retail rate regulation.

Nuclear Generation

Nuclear generation makes up 10 percent of the U.S. installed power generation capacity by fuel and about 20 percent of actual net generation each year.[4] Electric industry restructuring led to consolidation of nuclear operations through the purchase and sale of nuclear facilities across the country by experienced nuclear fleet operators such as Exelon and Entergy. Global Energy's analysis focused on a view of nuclear generation based on the classifications of plants owned and operated by IOUs and competitive plants that were sold and purchased.

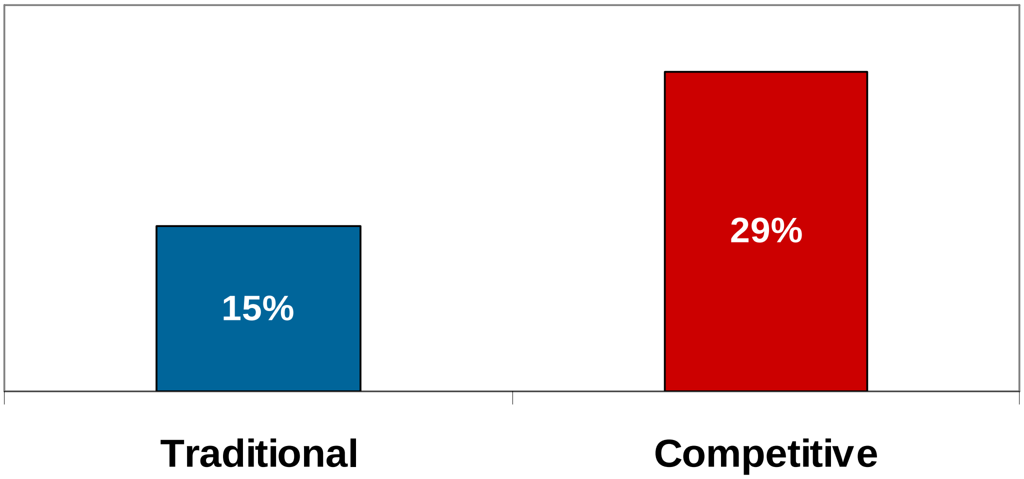
A number of nuclear facilities prior to wholesale competition were considered "troubled" and in danger of being shut down and decommissioned. Under competitive market conditions, many of these nuclear power plants have been sold, or their operation was contracted out to experienced nuclear fleet operators on a merchant basis. Consumers have benefited from the continued operation of these units, in addition to the improvements in operation and efficiencies.

[4] Global Energy Reference Case.

Nuclear Plant Refueling Outage Time Reduced

Global Energy conducted an analysis and review of the (Nuclear Regulatory Commission (NRC) daily unit outage information. Competitive units experienced a 29 percent reduction in the length of refueling outages since 1999. Figure RS-5 depicts the percentage improvement.

Figure RS-5
Percent Reduction in Length of Refueling Outages since 1999



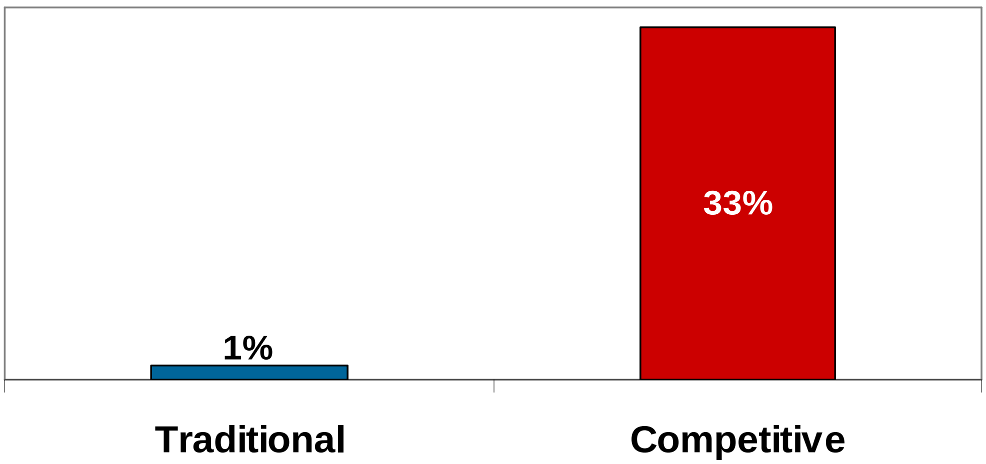
SOURCE: Global Energy.

Overall, the industry experienced a decline in total refueling outage days of nearly a year. Competition and industry restructuring have positively influenced the management of nuclear facilities through competitive pricing.

Nuclear Plant Operations & Maintenance Expenses Lowered

Global Energy conducted an analysis of the nuclear facilities' total fixed and variable operations and maintenance expenses. Competitive units experienced a 33 percent reduction in O&M expense on a $/MWh over 1999, as displayed in Figure RS-6. Competitive facilities have consistently reduced expenses over the study period.

Figure RS-6
Nuclear Plant O&M Reductions since 1999



SOURCE: Global Energy.

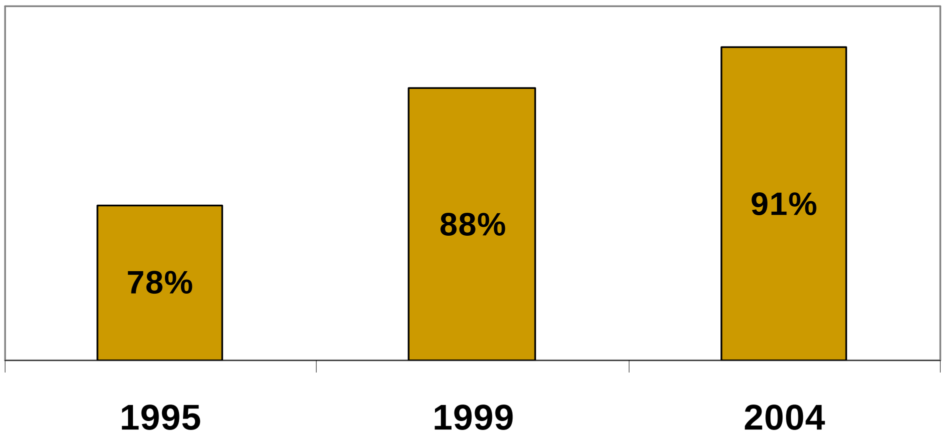
Note that in 1999, competitive nuclear facilities were experiencing costs of almost $15/MWh whereas traditional facilities' costs were around $10/MWh. The disparity is largely due to the fact that the competitive fleet of nuclear plants had a higher cost structure prior to their transfer to, or acquisition by, the Competitive sector. In 1999, the competitive nuclear facilities were relatively poor performers in the nuclear industry in regard to operating costs. However, by 2004, the skill of large scale experienced nuclear fleet operators; the standardization of procedures and maintenance; and the combined buying power for fuel, equipment, and supplies dramatically improved plant costs and performance. Now, the "poor performers" are indistinguishable from traditional facilities, as both have operating and maintenance costs of approximately $10/MWh.

Nuclear Plant Capacity Factors Increased

Nuclear units have relatively low variable costs and are, thus, low dispatch-cost generating facilities. As such, a measurable benefit is a high capacity factor. Prior to competitive forces shifting the management and operation of nuclear facilities to more experienced operators focused on improving plant performance in a competitive market environment, nuclear facilities were often operating at "sub-optimal" levels in 1995. Since 1995, the nuclear units have displayed continual improvement. According to Nuclear Energy Institute (NEI), nuclear plants had record output and stable costs in 2004. U.S. plants generated a record 786.5 million MWh in 2004, breaking the 2002 record of 780 million MWh. NEI's figures put the 2004 average net capacity factor at 90.6 percent, trailing only the 91.9 percent achieved in 2002 and the 90.7 percent in 2001. The slightly lower capacity factor, despite the higher output, occurred because nuclear operators nationwide have been uprating their units.

The nuclear industry experienced a 17 percent increase in capacity factors since 1995. Global Energy also found that since 1995 the increase in capacity factor resulted in enough energy to power more than 10 million residential households for one year.[5] Figure RS-7 depicts the overall capacity factor for the industry.

Figure RS-7
Nuclear Plant Capacity Factors; 1995-2004



SOURCE: Global Energy.

Coal Generation

Coal-fueled generation is the most predominant type of generating resource in the United States. Even with the additional natural gas-fueled generation, coal still represented 51 percent of total net generation in 2004.

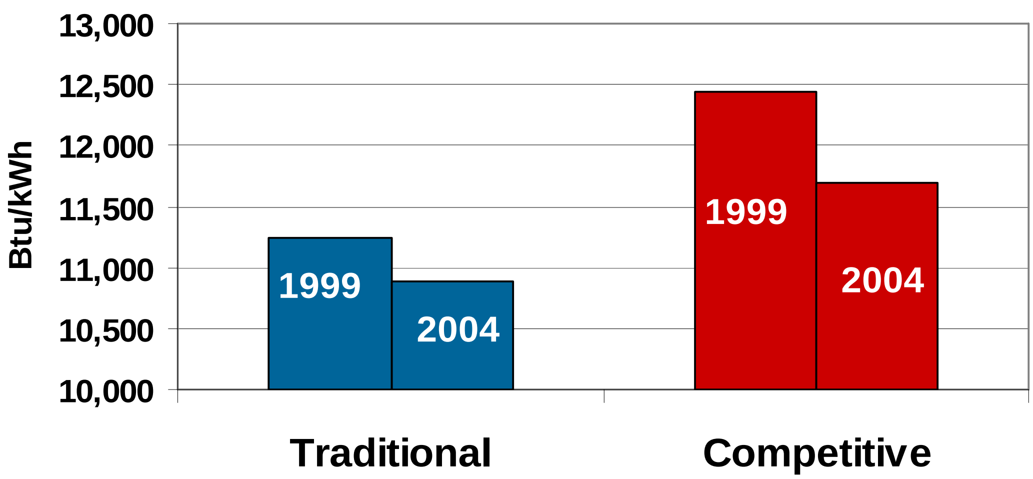
To identify how competitive pressures affected coal generation Global Energy conducted an analysis of coal-fueled generation based on a classification of traditional utility and competitive industry structures. Traditional utility structures represent generating facilities owned by investor-owned utilities, municipalities, and cooperatives that are subject to retail rate regulation. Competitive industry structures represent generating facilities owned by independent power producers that are not subject to retail rate regulation.

[5] Based on average residential customer annual usage of 10,803 kWh per year.

Coal Heat Rates Improved

Heat rate is a measurement of a generating station's thermal efficiency and is usually expressed in Btu/kWh; the lower the Btu/kWh, the higher the efficiency of the unit. Figure RS-8 shows that competitive units improved heat rates by 6 percent, while traditional units improved 3 percent since 1999. Overall, industry-wide heat rates for coal plants improved 4 percent during the study period. The traditional units consist of a more modern fleet, while the competitive units are older, less-efficient performers before they were transferred or sold by the prior owners. Nevertheless, the new competitive owners were able to achieve a 6 percent heat rate improvement. The environmental impact of the heat rate improvement is 12.3 million fewer tons of coal burned each year for the competitive fleet.

Figure RS-8
Coal Heat Rate Improvements



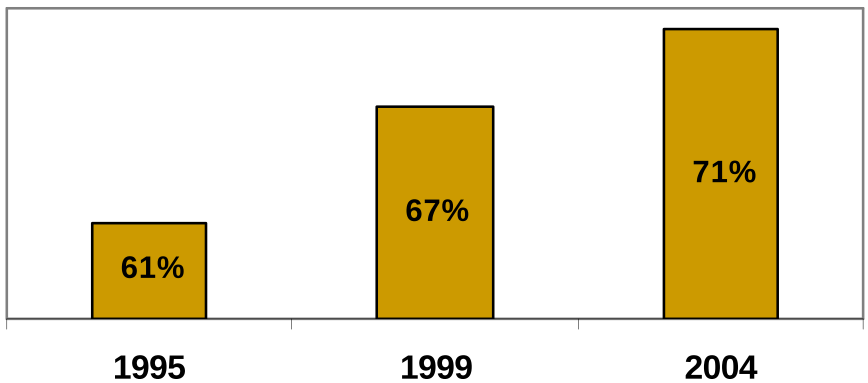
SOURCE: Global Energy.

Competitive pressures have compelled traditional utilities to maintain costs, while improving their overall efficiency. Consumers benefit from the overall improvement in efficiencies of coal generation regardless of whether they are related to traditional or competitive facilities.

Coal Plant Capacity Factors Increased

As with nuclear plants, the fleet of coal plants saw an improvement in capacity factors in the decade between 1995 and 2004. Figure RS-9 demonstrates that coal-fueled power plant capacity factors increased overall by 16 percent, from 61 percent to 71 percent. Because there are three times as many MW of coal-fueled capacity as there are MW of nuclear plant capacity, this increase had the effect of making at least another 50,000 MW of effective generating capacity available for dispatch in 2004 as there was prior to 1995. Furthermore, the increase in capacity factors for coal-based plants was enough electricity to power 25 million residential households for a year.

Figure RS-9
Coal Plant Capacity Factors; 1995-2004

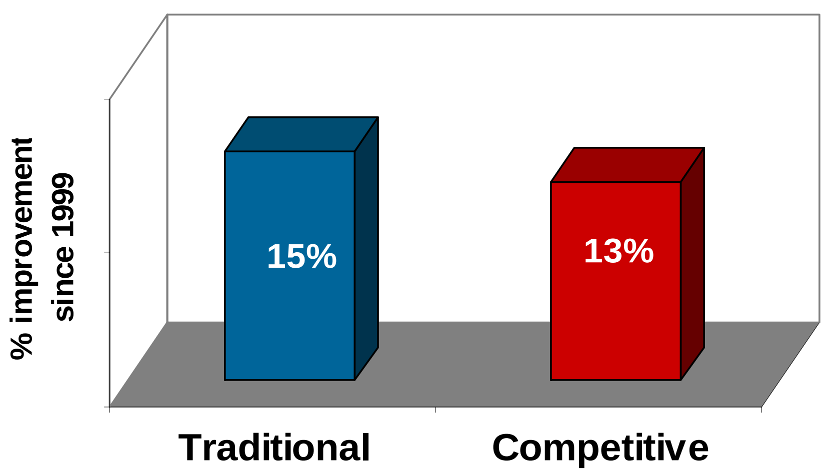


SOURCE: Global Energy.

Coal Operation & Maintenance Expenses Declined

Global Energy conducted an analysis of the coal fleet's operation and maintenance expenses to ascertain any influences of competition on these costs. Overall, coal O&M expense has declined when adjusted for inflation. Figure RS-10 shows that Competitive facilities improved 13 percent, while Traditional experienced a 15 percent improvement.

Figure RS-10
Coal O&M Improvements



SOURCE: Global Energy.

Reductions in the operating costs of base load, lower-cost plants, such as coal, benefit consumers through lower purchased power costs and regulated entities' ability to manage costs such that increases in rates are not necessary.

Summary - Improved the Efficiency of Power Plants

The empirical evidence indicates that the electric utility industry has improved its operations and efficiencies. Competitive utility structures are at the forefront of these improvements, either directly or indirectly, as demonstrated by the dramatic change in operating performance. Nuclear power plant performance improvements, in particular, have turned these plants, once considered to be an albatross around the neck of utilities, into star performers for the Regulated and Competitive plant operators skilled in running a fleet of nuclear plants.

Opening PJM to More Electric Supply Competitors Produced $85.4 Million in Production Cost Savings for Wholesale Power Customers

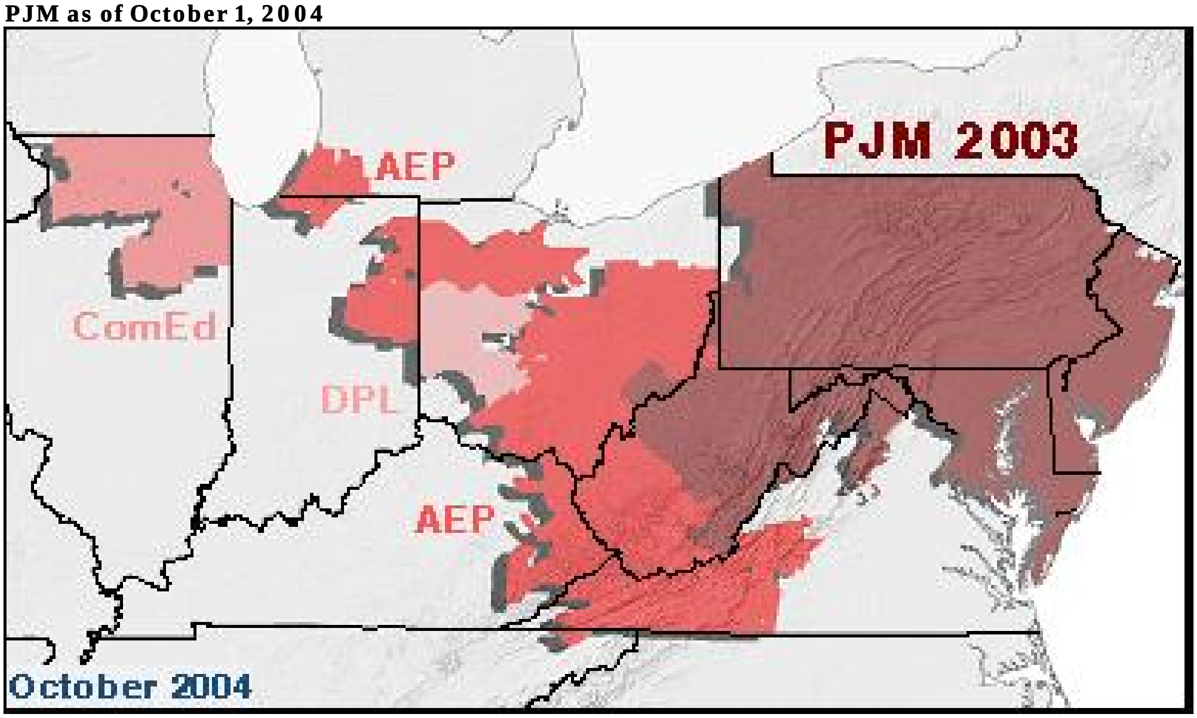
To test the impact of competition in expanded wholesale power markets, Global Energy assessed the impacts of integrating Commonwealth Edison (ComEd), American Electric Power (AEP) and Dayton Power & Light (DPL) into the PJM regional power market. The results of the analysis were that the benefits of expanding the PJM wholesale power market in 2004 produced $85.4 million in annualized production cost savings to wholesale customers in the Eastern Interconnection.

These savings were achieved through reduced transmission barriers, or seams, and the entry of new competitors to the market. FERC decisions have enabled additional market participants such as Exelon's ComEd, AEP, and DPL to join the PJM market. The results of competitive forces at work was immediate, sending price signals throughout the broader regional power markets where power buyers searching for the lowest-cost supply available found them from a now wider universe of generators, marketers and suppliers.

PJM Case Study

The integration of ComEd, AEP and DPL resulted in significant growth in the PJM market. In 2003, PJM comprised 76,000 MW of installed generating capacity and a peak load of 63,000 MW. By October of 2004, PJM comprised 144,000 MW of installed capacity and approximately 107,800 MW of peak load.

Figure RS-11
PJM as of October 1, 2004



SOURCE: Global Energy.

According to an internal analysis performed by PJM of the locational marginal prices (LMPs) in its energy spot markets, the impact of supply and demand fundamentals on market behavior from 2003 to 2004 translated into lower power prices for PJM. While average PJM power prices actually increased by 7.5 percent from 2003 to 2004, PJM showed that the increase was primarily a result of higher fuel prices. PJM performed a fuel adjustment of PJM prices and determined that fuel-adjusted PJM power prices actually declined by 4.2 percent from 2003 to 2004.

Table RS-3
PJM Load-weighted LMP ($ per MWh); 2003 to 2004

	2003	2004	Change
Average LMP	$41.23	$44.34	7.5%
Fuel Adjusted LMP	$41.23	$39.49	-4.2%

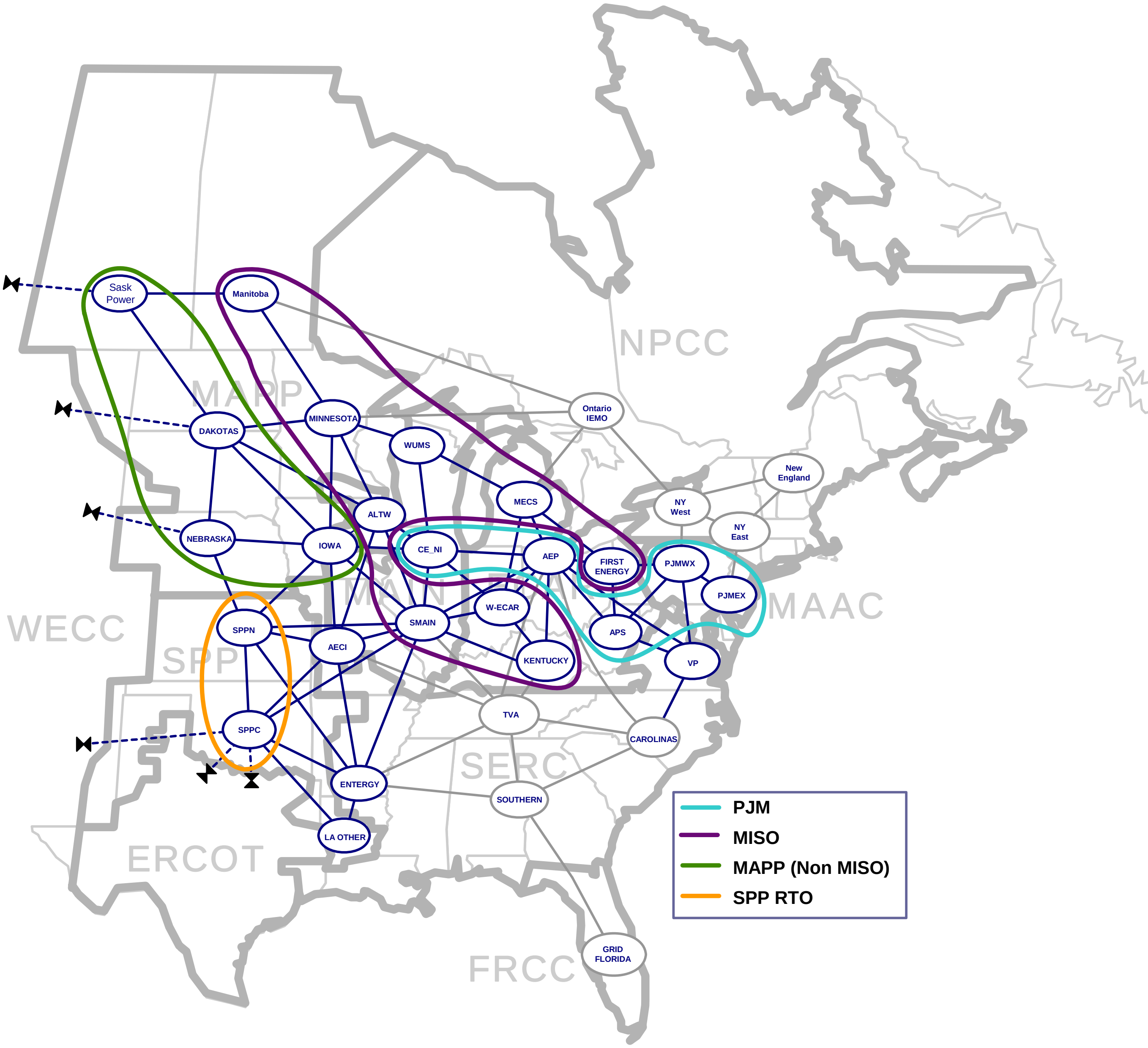
SOURCE: PJM.

Global Energy's PJM Case Study Approach

For this case study, Global Energy modeled the Eastern Interconnection power market to test PJM's conclusions; account for all price determinants not directly related to the integration; and to quantify the impacts associated with the integration of ComEd, AEP, and DPL supply and demand with that of PJM. Global Energy's approach was to analyze and quantify the impact of reducing the seams, in the form of pancaked wheeling charges, between the ComEd, AEP, DPL, and PJM energy markets. By isolating pancaked wheeling charges in its analysis, Global Energy captured the primary structural change to ComEd, AEP, DPL, and PJM's energy market supply and demand.

Global Energy employed a production cost savings model using its **EnerPrise™ Market Analytics** module, which measures production costs, such as fuel and operations and maintenance costs. The study compared the production costs of a "Competition" case, which simulated PJM as it was in 2004, and compared these costs with a "Without Competition" case that would have existed in 2004 if ComEd, AEP, and DPL had not joined PJM. Because Dominion Resources in Virginia did not join PJM until January 1, 2005, it was not included in this analysis.

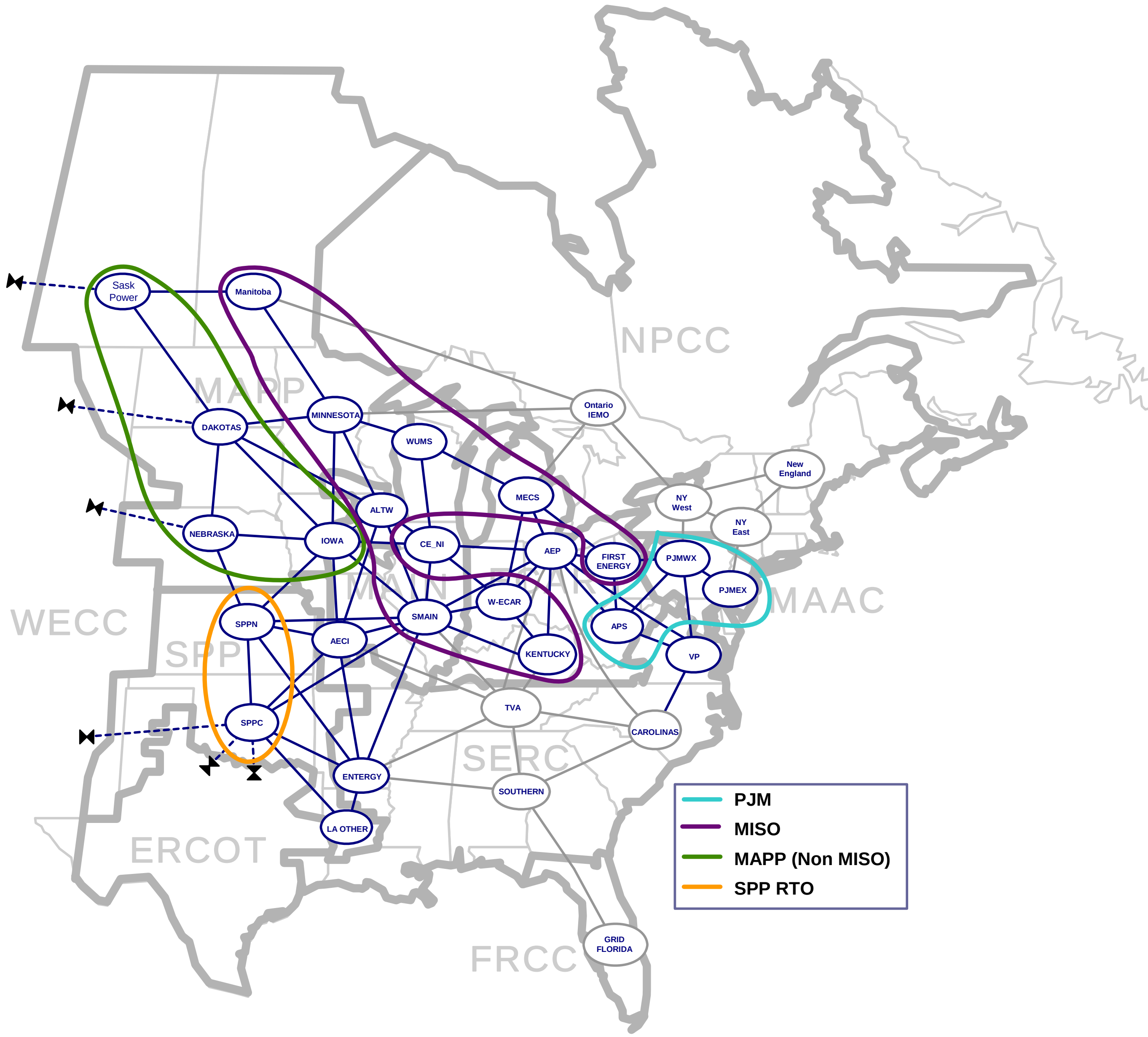
Figure RS-12
Competition Case Market Topology as of October 1, 2004



SOURCE: Global Energy.

In the Without Competition case, the market topology is similar to the Competition case except that ComEd (represented by the CE_NI zone) and AEP and DPL (both represented by the AEP zone) are modeled outside the PJM RTO and pancaked wheeling between the zones is not eliminated.

Figure RS-13
No Competition Case Market Topology for 2004



SOURCE: Global Energy.

Other Potential Benefits of PJM Integration

In addition to the integration of supply and demand in the wholesale energy market, brought about by the reduction of transmission seams between market areas, there are other significant benefits to RTO membership and the integration of energy markets and services in general that were not considered in this study. For example, AEP and DPL are now integrated with APS in a single spinning reserves market.

For regulation services, ComEd, AEP, DPL, and APS are all members of PJM's integrated Western Zone. PJM also coordinates generation and transmission maintenance for the entire RTO, as well as Available Transmission Capacity (ATC). These and other potential benefits are not captured in this analysis.

Summary - Opening PJM to More Electric Supply Competitors Produced Savings

Global Energy's analysis supports PJM's conclusion that, in 2004, changes in supply and demand fundamentals resulted in lower PJM prices in 2004 than 2003. Global Energy quantified the production cost savings associated with the reduction of seams between these ComEd, AEP, DPL, and PJM's energy markets at approximately $29.5 million for PJM in 2004 and $36.4 million for the Eastern Interconnection. Because these savings are based on the actual integration schedule for ComEd (May 2004) and AEP/DPL (October 2004), they represent savings for a partial year of integration in 2004. In order to quantify the benefits associated with a full year of integration, Global Energy performed the analysis as if ComEd, AEP, and DPL joined PJM on January 1, 2004. The estimated annualized production cost savings for PJM and the Eastern Interconnection were $69.8 million and $85.4 million, respectively.

Table RS-4
Estimated Benefits of Energy Market Integration in 2004

2004 Production Cost Savings		
Market Area	Savings based on 2004 PJM Integration Timeline (ComEd in May 2004 and AEP/DPL in October 2004	Annualized Savings (Simulates Integration of ComEd, AEP, DPL on January 1, 2004
PJM	$29.5 MM	$69.8 MM
Eastern Interconnect	$36.4 MM	$85.4 MM

SOURCE: Global Energy.

RTO formation has opened the doors to broad market access for customers, not only to merchant generators and suppliers in a more competitive market environment, but also increasingly to renewable energy from wind and other sources. The annual production cost savings for the PJM expansion will repeat year after year.

Conclusion

Wholesale competition is lowering the costs of providing electric energy to retail customers, just as Congress, FERC, state regulatory commissions, and ratepayer advocates intended. The effect of competition at work has been to shift the expense and risk of building power plants from utility customers to the competitive power plant owner and operator and the competitive power supplier, generally. Electricity customers benefited by more than $15.1 billion over the five-year study period, compared with what they would have been expected to pay under a more traditional utility environment without competition. Had competitive generators and power suppliers not emerged, regulated utilities would have been required to build rate base generating assets and incur the costs to run them. Under wholesale competition, merchant energy suppliers take the risk of building and operating the power plants and selling the energy output to utility players.

These regulated utilities paid the competitive merchant sector more than $13.7 billion for the energy and capacity in the study period. However, in the Without Wholesale Competition alternative, there would have been an additional $28.9 billion in operating expenses. Thus, the consumer benefited by more than $15.1 billion when all the costs, including the cost to buy merchant power, were considered over the more traditional process of allowing utilities to build the assets and incur the increased cost of fuel, O&M, depreciation, taxes, and operating income to run them.

Competitive wholesale energy markets have made substantial progress in giving energy consumers the benefits of competition in lower wholesale energy prices than otherwise would have been available, as well as improved efficiency and better reliability. The change in operating performance between traditional regulated utility power plant performance and competitive generator performance has been dramatic. Nuclear power plant performance improvements, in particular, have turned these plants—once thought to be an albatross around the neck of utilities—into star performers for the utility and competitive plant operators skilled in running a fleet of nuclear plants. Similar performance improvements have been seen in coal-fueled generation, as well.

RTO formation has opened the doors to broad market access for customers, not only to merchant generators and suppliers in a more competitive market environment, but also increasingly to renewable energy from wind and other sources.

Putting competitive power markets to the test resulted in savings of $15.1 billion for consumers over the five-year study period (1993-2003). And given that consumer benefits are tied to merchant power plant investment, the savings will continue to accumulate into the future.

Section One
Consumer Value of Competition

Consumer Value of Competition

Introduction

To assess whether wholesale competition is working as Congress and FERC intended, Global Energy assessed the Eastern Interconnection wholesale electric power markets as they occurred in the 1999-2003 study period (“With Wholesale Competition” case). Those results were compared to a simulation, which excluded the regulatory changes, tariff protocols and market rules that enabled wholesale competition (“Without Wholesale Competition” case). Refer to Appendix A for Global Energy’s discussion of wholesale competition.

Global Energy’s With Wholesale Competition case divided the Eastern Interconnection into two distinct business sectors. The “Regulated” sector is comprised of traditional regulated utilities, which have an obligation to serve native load retail customers. The “Competitive” sector is comprised of the exempt wholesale or merchant generating units, which are at risk as they are not allowed a regulated return. In this analysis, the sole source of income for the Competitive sector is energy and capacity sales to the Regulated sector.

The Without Wholesale Competition case calculated the consumer cost had the market remained as traditional, vertically integrated utilities operating in a regulated environment without wholesale competition. Global Energy used its generally available Strategic Planning™ software to replicate the market rules and conditions and to calculate the customer benefits. Customers benefited if the study showed a positive difference (lower costs) between current market conditions and the simulation of the traditional utility market prior to wholesale competition. The results of the analysis are that consumers in the Eastern Interconnection have realized a $15.1 billion consumer benefit due to wholesale competition over what they would have realized under the traditional regulated utility environment. Refer to Appendix B for Strategic Planning model overview.

The market rules in effect during the study period included the following FERC Competitive Power Market Initiatives:

- Order 888. The wholesale electricity landscape changed when FERC issued its order 888 in 1996, requiring public utilities that owned, operated or controlled transmission assets to file open access tariffs, opening their transmission system to competition on non-discriminatory basis. Order 888 also provided for the full recovery of stranded costs. While FERC has not required the formation of ISOs, it has provided guidelines for their creation for utilities that sought a more effective means for the operational unbundling of transmission and generation.
- FERC introduced the ISO as an independent organization that was responsible for providing non-discriminatory access to the transmission system and ancillary services; ensuring the short-term reliability of grid operations; controlling interconnected transmission facilities within its region; identifying and taking operational action to relieve transmission constraints; and coordinating with neighboring control areas.
- Order 889 mandating each utility to establish or participate in an Open Access Same Time Information System (OASIS) to share information about available transmission capacity followed order 888.
- Order 2000. In December 1999, FERC issued its Order 2000, requiring public utilities that owned, operated or controlled interstate transmission facilities to make regulatory filing of their intent to

form or participate in a regional transmission organization (RTO). FERC envisioned RTO formation and development as the tool to promote efficiency in the wholesale electricity markets and eventually lower costs for wholesale and retail consumers of electricity, while maintaining reliable service. As such, a regional transmission organization would be responsible for improving transmission grid management efficiency, improving grid reliability, and preventing discriminatory transmission practices.

The valuation method Global Energy employed in the analysis is the minimization of operating expenses for the regulated utility sector. Under traditional utility cost of service regulation, the minimization of operating expenses provides the greatest benefit to the retail customer. Global Energy assumed all operating expenses were fully recovered in the base revenues of the regulated utility sector. The operating expenses include fuel expenses, energy and capacity purchases from the Competitive sector, variable O&M, fixed O&M, depreciation, taxes, and operating income.[1]

Global Energy used a fundamentals-based methodology to perform the analysis, modeling the details of unit characteristics, hourly demand, fuel prices, and transmission. Using its own Energy Velocity data source and market-leading Strategic Planning software, the modeling methodologies and approach are consistent with Global Energy's consulting best practice for cost benefit studies.

The Consumer Value of Competition analysis was performed in three distinct progressive steps.

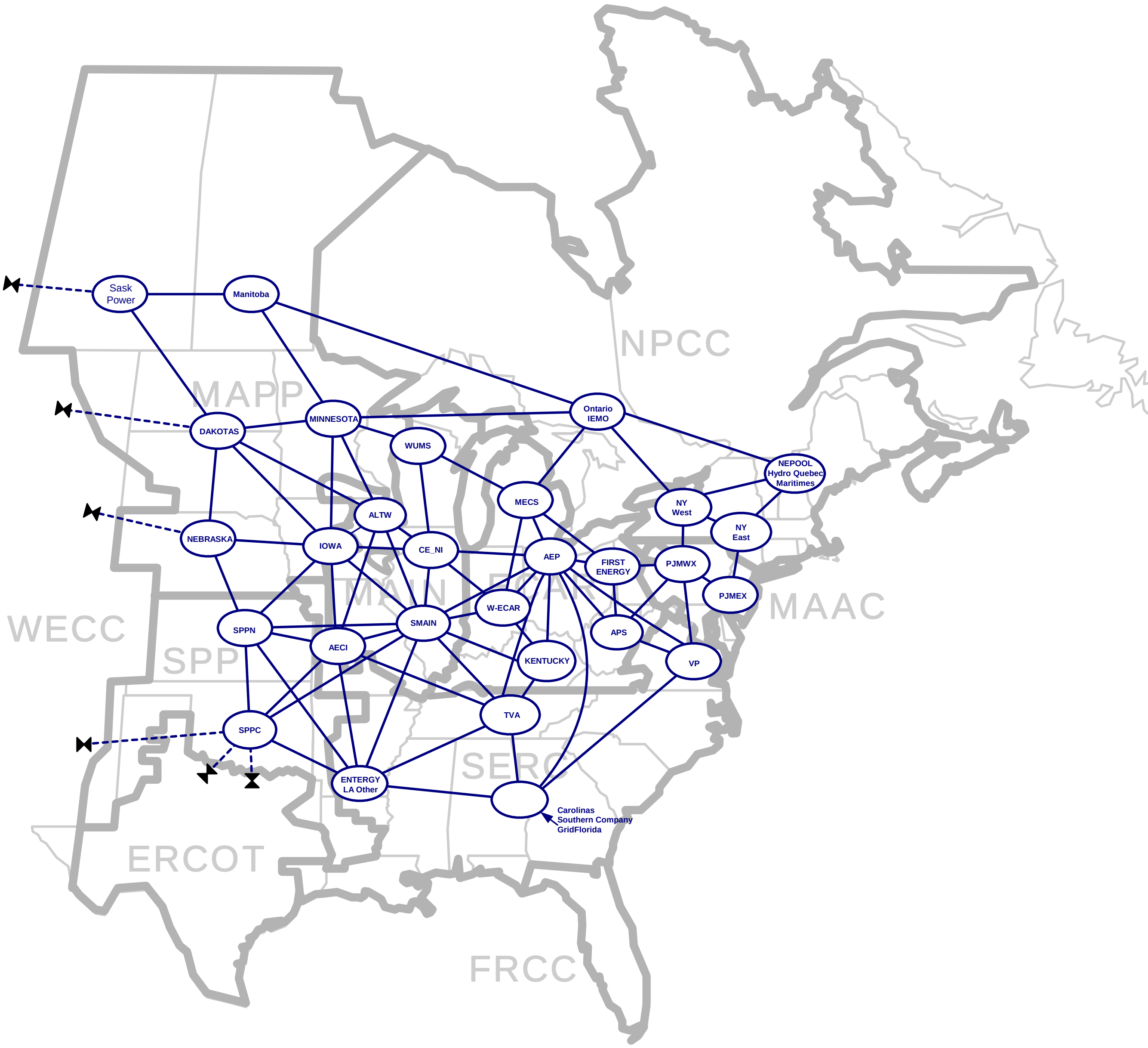
1. **With Wholesale Competition Simulation.** The Strategic Planning model was calibrated so unit performance, market prices, and power flows were similar to observed market conditions for the 1999-2003 study period. Once calibrated, the value of the energy and capacity sales made by the Competitive sector to the Traditional sector was included in a cost of service calculation.
2. **Without Wholesale Competition Simulation.** For the Without Wholesale Competition Case, Global Energy modeled how the Eastern Interconnection most likely would have looked had Congress not passed the National Energy Policy Act of 1992 (EPAct). In this simulation, there are no competitive power plants, no regional transmission organizations, and wholesale energy is exchanged at marginal cost based contracts rather than wholesale market-based pricing.
3. **Result Comparison.** To compare the two cases, Global Energy utilized the pro forma financial and rate making capabilities of its Strategic Planning software, modeling cost of service of the Regulated sector for each case. The case with the lowest cost of service provided the greatest consumer benefit.

Market Topology

Global Energy divided the Eastern Interconnection into the market areas illustrated in Figure 1-1. As shown, the 29 market areas traverse eight NERC regional councils—namely FRCC, MAPP, MAIN, NPCC, ECAR, MAAC, SERC and SPP. Within the market areas it was assumed that there were no significant transmission constraints and therefore no transmission costs for moving power within each transmission market zone. Hourly loads were assigned to the market areas based on the FERC filings of the utilities located in each area.

[1] For the Regulated Sector, Operating Income is defined as rate base times a "fair and reasonable" allowed return on rate base of 8.5 percent.

Figure 1-1
Market Configuration



SOURCE: Global Energy.

Calibration

Global Energy used a fundamentals-based approach to calibrate unit performance, market prices, and power flows. Based on its proprietary Strategic Planning system—a proven data management and production simulation model—Global Energy simulated the operation of each generating unit of the Eastern Interconnection. Strategic Planning is a sophisticated state-of-the-art, multi-area, chronological production/market simulation model. Included with each Strategic Planning simulation are pro forma financials, providing users with a complete enterprise-wide solution.

For each region, Strategic Planning considered:

- Individual generating unit characteristics including heat rates, variable O&M, fixed O&M, and other technical characteristics;
- Transmission line interconnections, ratings, and wheeling rates;
- Resource additions and retirements;
- Nuclear unit outages and refuelings;
- Hourly loads for each utility or load serving entity in the region; and
- The cost of fuels that supply the plants.

Strategic Planning simulated the operation of individual generators, utilities, and control areas to meet fluctuating loads within the region with hourly detail. The model is based on a zonal approach where market areas (zones) are delineated by critical transmission constraints. The simulation is based on a mathematical function that performs economic power exchanges across zones until all eligible economic exchanges have been made.

Global Energy's calibration methodology was to:

- Benchmark the model against observed prime mover output within the market zones;
- Benchmark the model against observed market prices; and
- Benchmark the model against observed power flows.

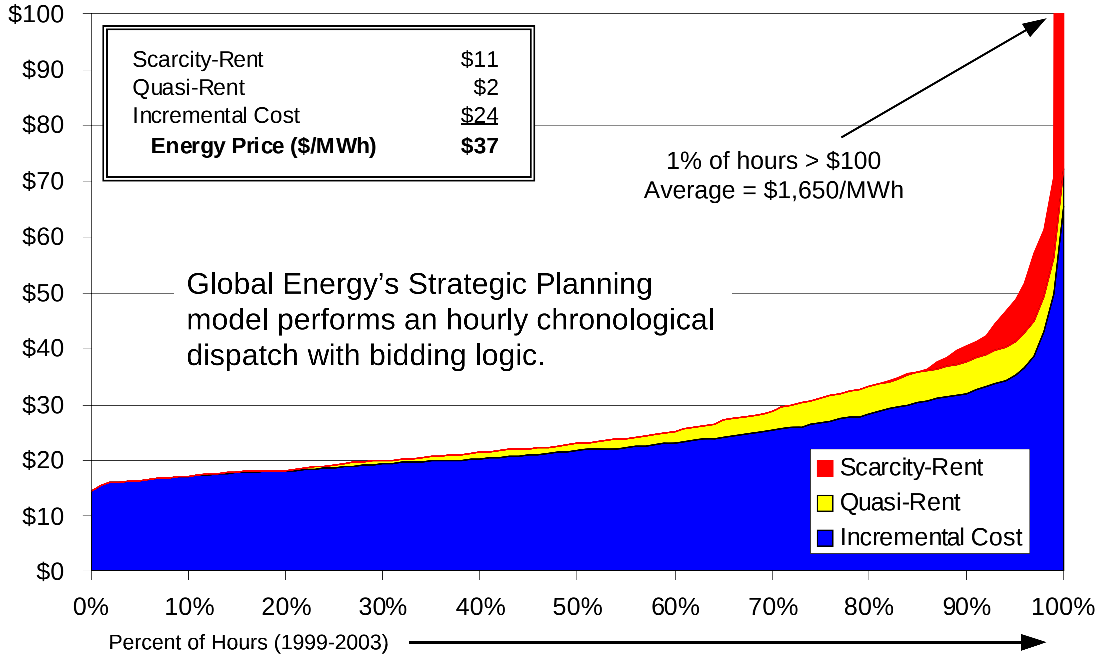
Bidding Behavior

To capture the unique bidding behavior of the energy market, Strategic Planning utilizes a dynamic bid adder algorithm that considers supply/demand conditions and technology type when submitting a bid. Figure 1-2 represents the various components of the Entergy 7x24 market clearing price from 1999-2003. Overall, the average price was $37/MWh. In replicating the bidding behavior of the Entergy power market, Global Energy captured the three key market price elements of:

- **Incremental Cost.** Includes fuel price, heat rate, and variable O&M. Under rational bidding, the incremental cost serves as a generator's minimum bid. As illustrated in Figure 1-2, the incremental cost component for the Entergy 7x24 market averaged $24/MWh.
- **Quasi-Rents Component.** Rent component added to the incremental cost to recover start-up costs, minimum-run costs, and a portion of fixed operating costs and financial expense. For the Entergy 7x24 market, the quasi-rents component averaged $2/MWh.
- **Scarcity-Rents Component.** Rent component added to the incremental cost and quasi-rent. As demand increases, there are fewer alternative sources of generation, providing the higher cost generators an opportunity to bid above their variable cost. For the Entergy 7x24 market, the scarcity component averaged $11/MWh.

Refer to Appendix B for more on the Strategic Planning bidding behavior.

Figure 1-2
Entergy 7x24 Daily Market Bid Components; 1999-2003

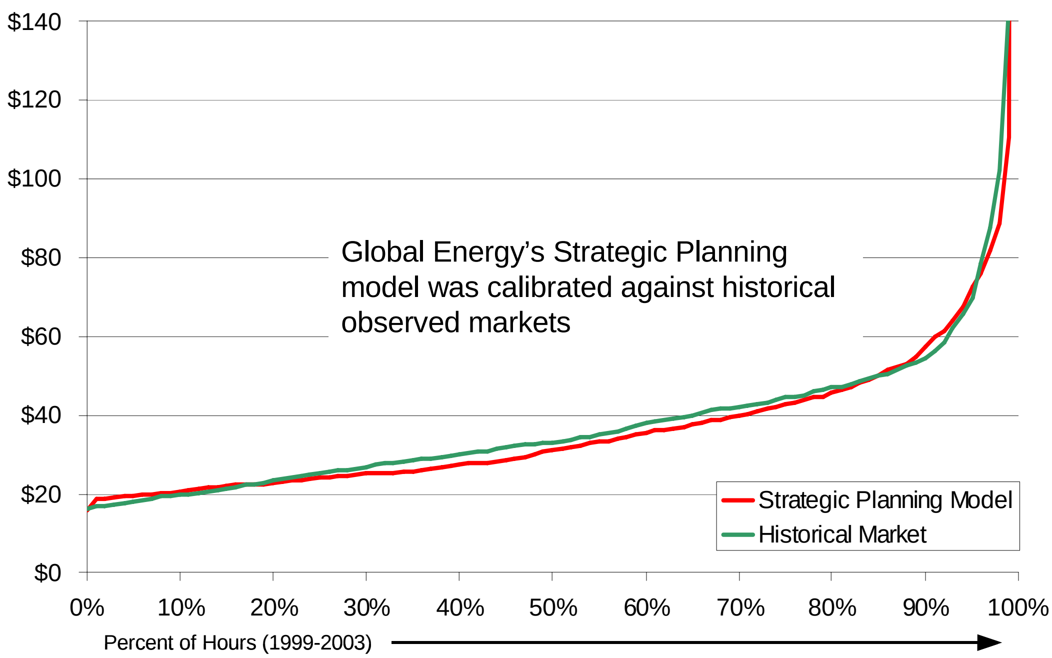


SOURCE: Global Energy.

Entergy Market Calibration

To ensure consistency with the observed markets, Global Energy performed a calibration of the Strategic Planning Quasi-Rent/Scarcity-Rent bidding behavior algorithm. Figure 1-3 is a graphical representation of the 5x16 Entergy market price calibration efforts.

Figure 1-3
Entergy 5x16 Daily Market Prices; 1999-2003



SOURCE: Global Energy.

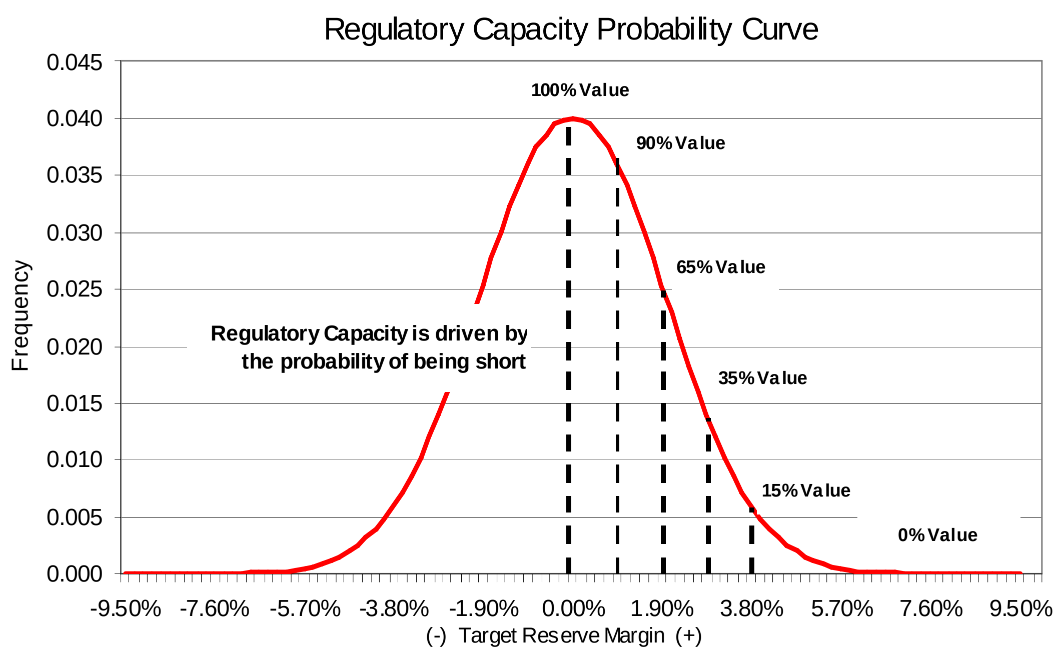
Generation Adequacy (ICAP/Regulatory Capacity)

To account for the capacity value for markets in the Northeast, Global Energy used the Installed Capacity (ICAP) markets to compensate the Competitive sector for their capacity. For non-RTO markets, Global Energy calculated the value of Regulatory Capacity (capacity with market-based energy).

Given Regulatory Capacity deals are bilateral and are not transparent, Global Energy devised a methodology to determine a proxy for Regulatory Capacity values. The methodology is based on the Load Serving Entity (LSE) buyer's perspective. Figure 1-4 illustrates the methodology an LSE uses to assess their reserve margin obligations. If the LSE forecasts a reserve margin obligation of 1,000 MW and they only have 950 MW of generation, then they would be willing to spend full market value (100 percent) for the 50 MW shortfall.

To account for the inherent uncertainty in the peak demand forecast, the LSE is willing to purchase additional capacity beyond the forecasted peak demand so long as the price is right (below full value). Figure 1-4 illustrates the diminishing value as a function of reserve margin. The diminishing Regulatory Capacity value fits a normal distribution that is correlated to the LSE's reserve margin uncertainty band.

Figure 1-4
Regulatory Capacity Probability Curve



SOURCE: Global Energy.

In the With Wholesale Competition case, competitive capacity owners receive Regulatory Capacity revenue driven by the distribution curve of Figure 1-4.

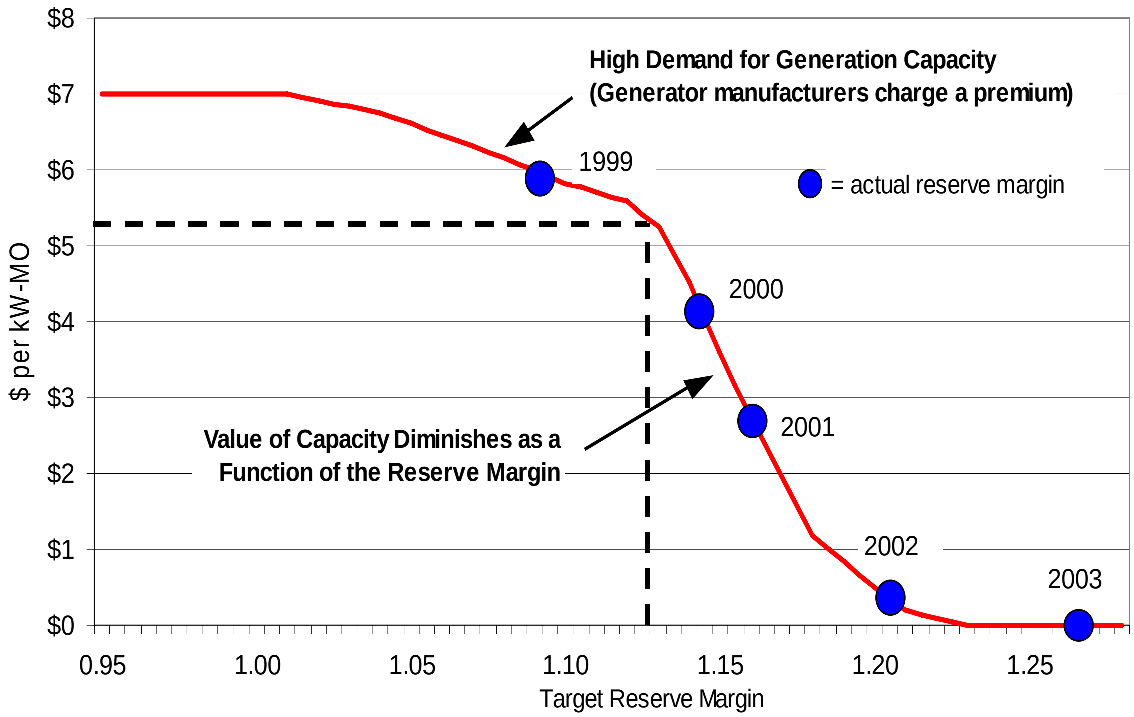
And, in times of very tight supply, the capacity owners receive Regulatory Capacity revenue above the 100 percent value if the reserve margin is well below the target. In 1999 and 2000, Regulatory Capacity prices were high due to a supply shortage. During this period of short supply, turbine manufacturers were able to increase the purchase price of a combustion turbine, plus buyers were willing to pay a reservation charge to obtain a place in queue for early delivery of a combustion turbine.

Eastern Interconnection Regulatory Capacity

The shape of the curve that Global Energy used to capture the plus/minus effect around a target reserve margin is illustrated in Figure 1-5. The capacity value, in $/kW-Month, is the levelized carrying charge of a combustion turbine plus recovery of the fixed O&M expense. The 100 percent recovery point is at the 13.6 percent target reserve margin. Sliding to the right of this point, an LSE pays less for Regulatory Capacity as the reserve margin increases. Sliding to the left, an LSE pays more for Regulatory Capacity as the supply/demand fundamentals drive the price higher.

The blue dots on the graph represent the actual reserve margin exhibited by the Eastern Interconnection market for the 1999-2003 study period. For this study, Global Energy calculated the value of Regulatory Capacity for each planning region. The target reserve margin varied by planning region in accordance with the requirements of the power pools. Figure 1-5 is a <u>composite</u> curve of all of the planning regions in the Eastern Interconnection.

Figure 1-5
Eastern Interconnection Composite Regulatory Capacity Value

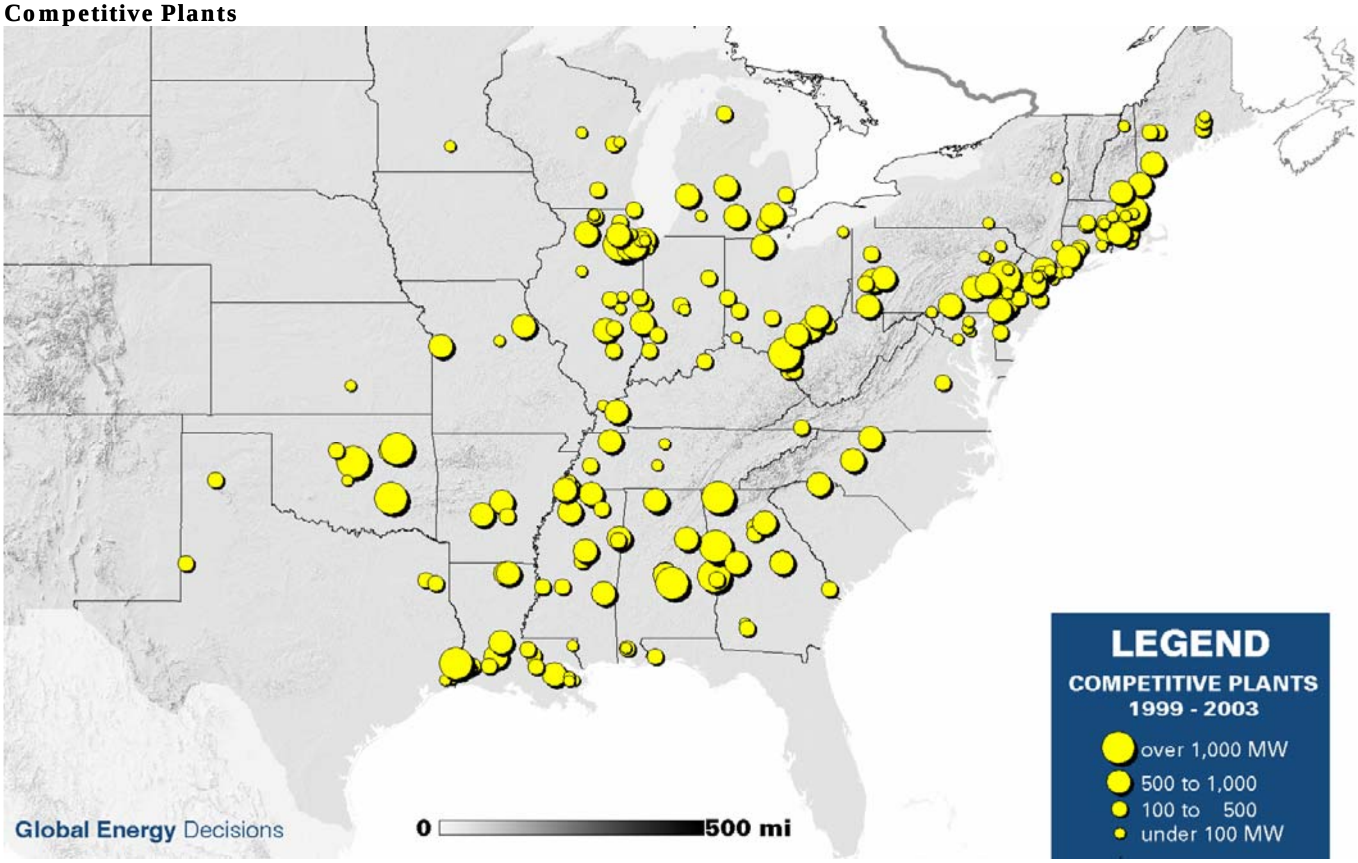


SOURCE: Global Energy.

Competitive Generation

During the 1999-2003 study period, 88,686 MW of competitive generation was added of which 56 percent was combined cycle and 44 percent was simple cycle. For this study, other fuel sources, such as waste coal and wind, were not included as part of the analysis. Figure 1-6 shows the dispersion of competitive plants added in the Eastern Interconnection during the study period.

Figure 1-6
Competitive Plants



Competitive Sector Capacity Value

To arrive at a Capacity Value for the Competitive sector, Global Energy used a methodology that compensated the owners for financial losses. The concept is that if the Competitive sector doesn't receive enough revenue from the energy market to cover its expenses plus a fair return on investment, then the LSEs would make up the difference.

The methodology is to calculate a profit and loss statement (P&L) for the Competitive sector to determine if it lost money. See Table 1-1.

If it did lose money, then the sliding slide of the Regulatory Capacity illustrated in Figure 1-5 was used to determine how much the LSE would be willing to pay for capacity. If the Regulatory Capacity value over-compensated the Competitive sector, a formula was used where the Capacity Value was equivalent to the minimum of either the financial loss or Regulatory Capacity value. Table 1-2 provides the calculation of the Capacity Value used in this study.

Table 1-1
Competitive Sector Profit and Loss Statement

Competitive Sector P&L	1999	2000	2001	2002	2003	1999-2003
Energy Revenue (millions $)	**$434**	**$1,166**	**$1,647**	**$3,279**	**$4,969**	**$11,495**
- Fuel	70	527	950	1,950	4,149	7,646
- Variable O&M	2	14	24	68	103	212
- Fixed Expenses	16	79	165	371	623	1253
- Levelized Carrying Charge	277	914	1,905	4,269	6,141	13,505
Profit/Losses	69	(368)	(1,397)	(3,378)	(6,047)	(11,121)

SOURCE: Global Energy.

Table 1-2
Capacity Value Calculation

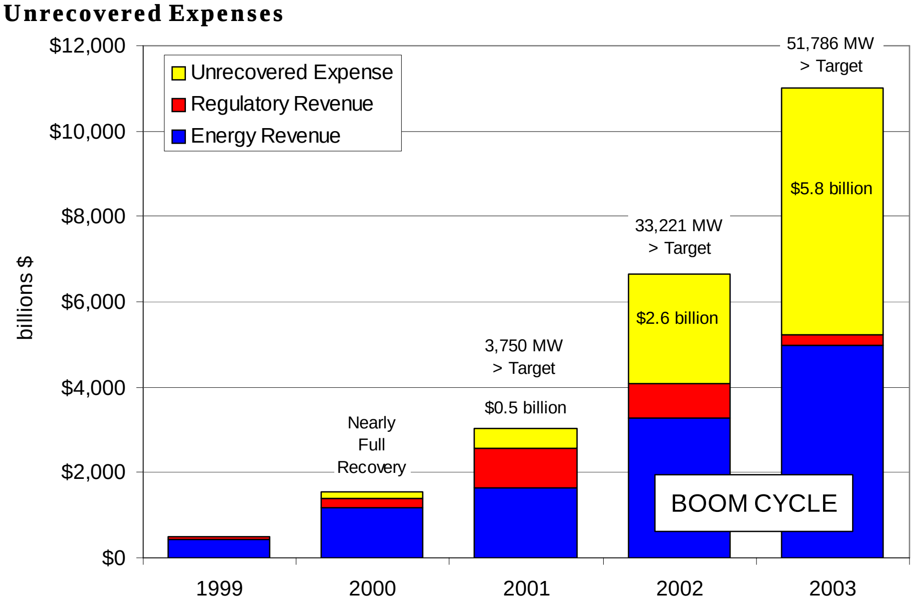
	1999	2000	2001	2002	2003	1999-2003
Losses (from Table 1-1)	0	(368)	(1,397)	(3,378)	(6,047)	N/A
Regulatory Capacity (millions $)	59	227	914	811	267	N/A
Capacity Value (millions $)	**$0**	**$227**	**$914**	**$811**	**$267**	**$2,220**

SOURCE: Global Energy.

Where Capacity Value = Minimum {Absolute Value (Losses), Regulatory Capacity}

Combining the energy revenue of $11.5 billion from Table 1-1 plus the capacity value of $2.2 billion from Table 1-2, the total revenue of the Competitive sector was determined to be $13.7 billion. This is the payment that the Regulated sector pays the Competitive sector in the With Wholesale Competition case. Figure 1-7 illustrates the Competitive sector's unrecovered expenses. As the graph illustrates, during boom cycles, the unrecovered expense is very large.

Figure 1-7
Unrecovered Expenses



SOURCE: Global Energy.

Competitive and Regulated Financial Exchange

From Tables 1-1 and 1-2, Global Energy estimates the Competitive sector sold $13.7 billion worth of energy and capacity to the Traditional sector. The values were $11.5 billion and $2.2 billion, respectively. Figure 1-8 illustrates the interaction between the Regulated sector and the Competitive sector for the With Wholesale Competition case.

Figure 1-8
With Wholesale Competition Case Financial Exchange

Regulated Sector

Operating Expenses

Fuel

+ Variable O&M

+ Energy Purchases

+ Capacity Purchases

Competitive Sector Revenues

SOURCE: Global Energy.

The five-year breakdown of the various Regulated sector expenses of the With Wholesale Competition case is shown in Table 1-3.

Table 1-3
With Wholesale Competition - Cost of Service

	1999	2000	2001	2002	2003	1999-2003
Fuel (Fossil and Nuclear)	28,905	31,651	31,600	31,188	33,627	156,971
+ Variable O&M	3,653	3,808	3,889	4,049	4,116	19,515
+ Competitive Energy Purchase	434	1,166	1,647	3,279	4,969	11,495
+ Competitive Capacity Value	0	227	914	811	267	2,220
+ Fixed O&M	-	-	-	-	-	-
+ Depreciation	-	-	-	-	-	-
+ Property Taxes	-	-	-	-	-	-
+ Income Taxes	-	-	-	-	-	-
+ Operating Income	-	-	-	-	-	-
Operating Expenses (millions $)	**32,992**	**36,851**	**38,050**	**39,328**	**42,980**	**190,200**

SOURCE: Global Energy.

Defining the Two Cases

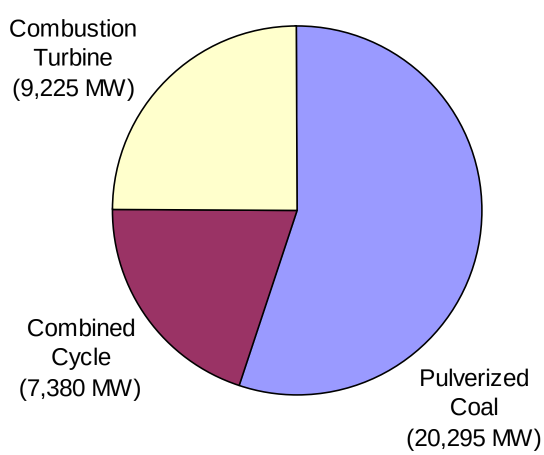
The With Wholesale Competition case differs from the Without Wholesale Competition case in three main areas.

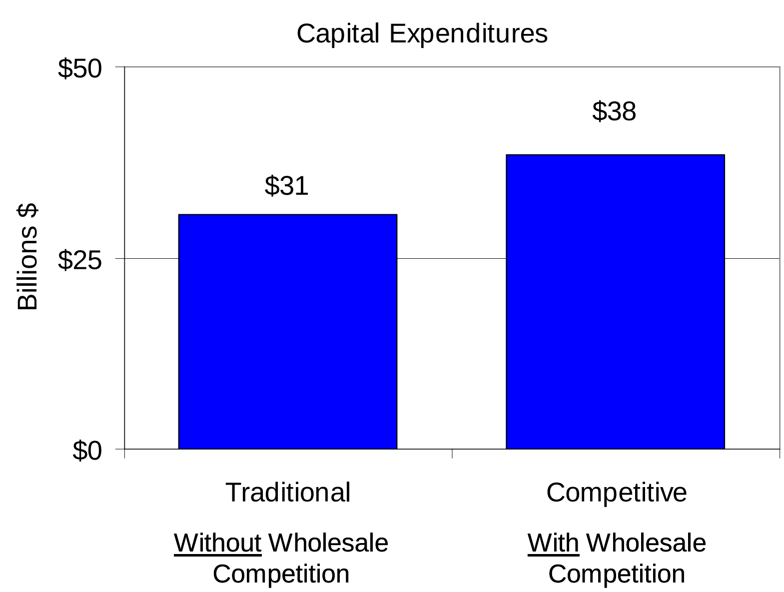
1. Competitive Plants
   - In the Without Wholesale Competition case, it is assumed that no competitive or merchant plants would have been built; however, qualifying facilities built pursuant to PURPA requirements were included.
2. Regional Transmission Organization (RTO)
   - In the Without Wholesale Competition case, it is assumed that FERC Orders 888 and 2000 never occurred and that RTOs were not formed. RTO transmission rates are replaced with pancaked transmission rates, which traditionally existed in these areas.
3. Market-Based Rates for Wholesale Energy
   - In the Without Wholesale Competition case, it is assumed that marginal cost-based contracts replace market-based wholesale energy.

Traditional Power Plant Development (Without Wholesale Competition Case)

In the Without Wholesale Competition case, Global Energy calculated the level and mix of new generation that utilities would have built to satisfy minimum reserve margins and consumer energy requirements. That electric supply portfolio would have consisted of 55 percent pulverized coal, 20 percent combined cycle, and 25 percent combustion turbines. As shown in Figure 1-9, capital spent by the Regulated sector is $7 billion less than was spent by the Competitive sector.

Figure 1-9
Traditional Generation Supply Portfolio



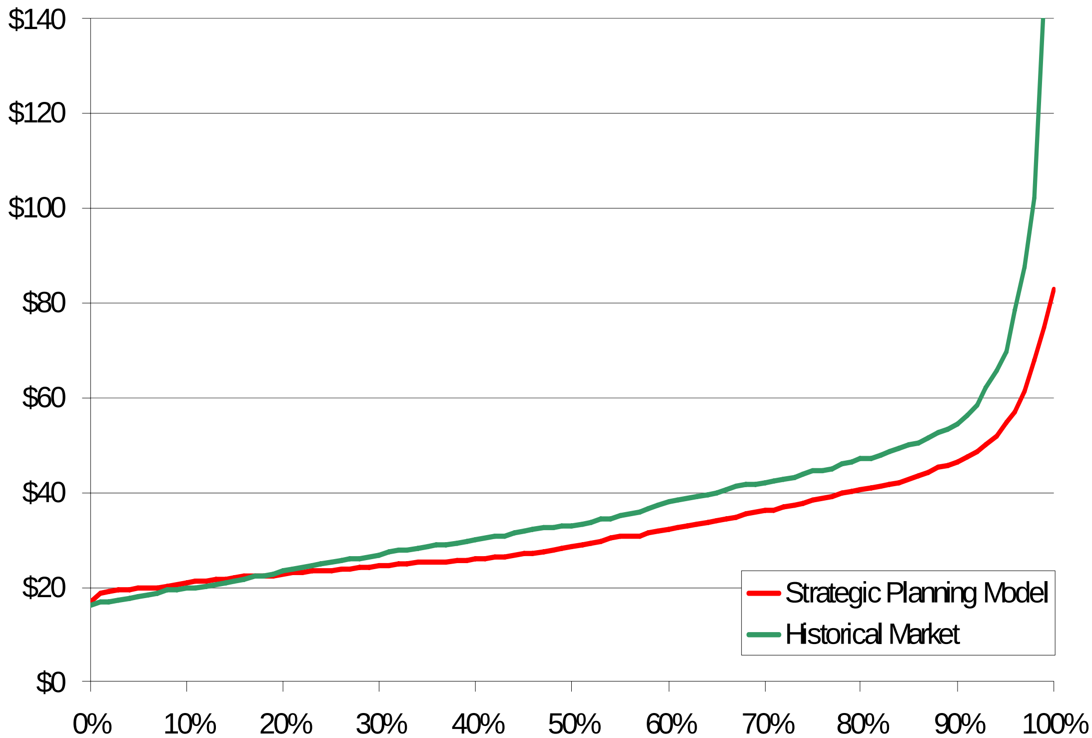


SOURCE: Global Energy.

Marginal Cost Based Energy Market

Figure 1-10 shows the market clearing price forecast derived from power exchanges at marginal cost based energy. This figure illustrates how the wholesale market behaves in Traditional Markets Without Wholesale Competition case.

Figure 1-10
Entergy 5x16 Marginal Cost Daily Market Prices; 1999-2003



SOURCE: Global Energy.

Return on Rate Base Calculation

Given the Regulated sector builds its own generation in the Without Wholesale Competition case, Global Energy calculated operating income for the incremental generation that was added using the return of rate base calculation and an allowed return on rate base of 8.5 percent.

Figure 1-11
Return on Rate Base

Revenues		
	Base Revenues	205,342
Expenses		
	Fuel	160,979
	Competitive Energy Purchases	0
	Competitive Capacity Value	0
	Variable O&M	21,902
	Fixed O&M	7,610
	Depreciation	2,670
	Property Taxes	931
	Income Taxes	3,289
Operating Income		
	Rate Base x Allowed Rate of Return	7,960

SOURCE: Global Energy.

The five-year breakdown of the various Regulated sector expenses of the Without Wholesale Competition case is shown in Table 1-4.

Table 1-4
Without Wholesale Competition - Cost of Service

	1999	2000	2001	2002	2003	1999-2003
Fuel (Fossil and Nuclear)	28,808	31,577	31,592	32,634	36,367	160,979
+ Variable O&M	3,919	4,194	4,399	4,633	4,757	21,902
+ Competitive Energy Purchase	-	-	-	-	-	-
+ Competitive Capacity Value	-	-	-	-	-	-
+ Fixed O&M	1,147	1,348	1,575	1,698	1,841	7,610
+ Depreciation	170	374	603	703	820	2,670
+ Property Taxes	35	112	201	269	314	931
+ Income Taxes	311	532	774	763	909	3,289
+ Operating Income	527	1,144	1,823	2,081	2,385	7,960
Operating Expenses (millions $)	**34,917**	**39,282**	**40,967**	**42,782**	**47,394**	**205,342**

SOURCE: Global Energy.

Comparing the Two Cases

The five-year consumer benefit of the With Wholesale Competition case versus the Without Wholesale Competition case was $15.1 billion. A comparative breakdown of the various expenses is shown in Table 1-5.

Table 1-5
Consumer Benefit - Cost of Service

	Without Wholesale Competition	With Wholesale Competition	Consumer Benefit
Fuel (Fossil and Nuclear)	160,979	156,971	4,008
+ Variable O&M	21,902	19,515	2,387
+ Competitive Energy Purchase	-	11,495	(11,495)
+ Competitive Capacity Value	-	2,220	(2,220)
+ Fixed O&M	7,610	-	7,610
+ Depreciation	2,670	-	2,670
+ Property Taxes	931	-	931
+ Income Taxes	3,289	-	3,289
+ Operating Income	7,960	-	7,960
Operating Expenses (millions $)	**205,341**	**190,201**	**15,140**

SOURCE: Global Energy.

The With Wholesale Competition case does not reflect expenses and returns associated with existing utility infrastructure. The Without Wholesale Competition case includes expenses and returns for new generation constructed by the Regulated sector. In essence, Global Energy is quantifying the cost and risk transfer of power plant construction between the two sectors (Competitive and Regulated). Table 1-6 provides a description of each variable of the operating statement.

Table 1-6
Operating Statement Variable Descriptions

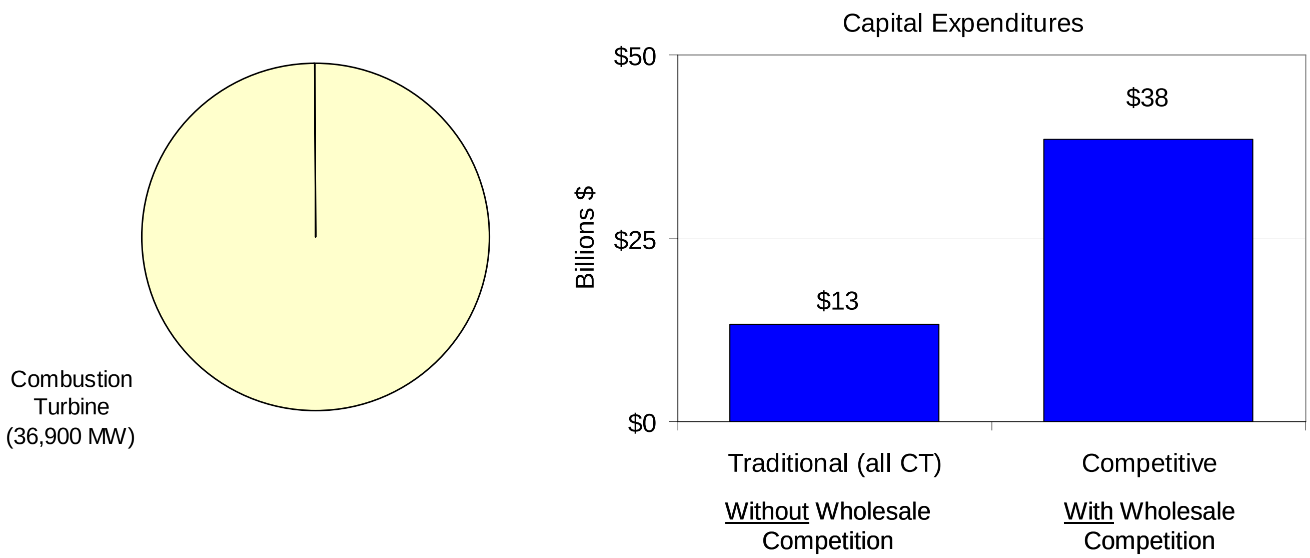
	Without Wholesale Competition	**With Wholesale Competition**
Fuel (Fossil and Nuclear)	Cost of fossil and nuclear fuel burned by existing utility infrastructure. This line item includes all plants (regardless of ownership) built prior to 1999, new rate base plants built in the 1999-2003 study period, and the 36,900 MW of traditional plants identified in Figure 1-9.	Cost of fossil and nuclear fuel burned by existing utility infrastructure. This line item includes all plants (regardless of ownership) built prior to 1999, plus new rate base plants built in the 1999-2003 study period. The 88,686 MW of competitive plants identified in Figure 1-6 are excluded from this line item.
Variable O&M	This line item includes all plants (regardless of ownership) built prior to 1999, new rate base plants built in the 1999-2003 study period, and the 36,900 MW of traditional plants identified in Figure 1-9.	This line item includes all plants (regardless of ownership) built prior to 1999, plus new rate base plants built in the 1999-2003 study period. The 88,686 MW of competitive plants identified in Figure 1-6 are excluded from this line item.
Competitive Energy Purchase	Not applicable. In this case there are no competitive plants.	Cost of energy purchased from the competitive plants identified in Figure 1-6.
Competitive Capacity Value		Cost of capacity purchased from the competitive plants identified in Figure 1-6.
Fixed O&M	These expenses are associated with the 36,900 MW of traditional plants constructed in the study period.	Expenses were not included for existing utility infrastructure because it would be the same for with and without cases.
Depreciation		
Property Taxes		
Income Taxes		
Operating Income	This line item is the operating income of the 36,900 MW of traditional plants constructed in the study period. The operating income is calculated as rate base times a return on rate base of 8.5 percent.	Operating income was not included for existing utility infrastructure because it would be the same for with and without cases.

SOURCE: Global Energy.

Low Capital Cost Sensitivity

One of the largest drivers of the $15.1 billion consumer benefit was the mix of new resources Global Energy assumed would be built. To stress test this assumption, Global Energy developed a low capital cost case in which only simple cycle combustion turbines were built.

Figure 1-12
Traditional Generation Supply Portfolio – Low Capital Cost Scenario



SOURCE: Global Energy.

Consumer Benefit of the Low Capital Cost Case

The five-year consumer benefit of the With Wholesale Competition case versus the Low Capital Cost case Without Wholesale Competition was $9.4 billion. A comparative breakdown of the various expenses is shown in Table 1-7. This case can be thought of as the least amount of consumer benefit or a “floor.”

Table 1-7
Low Capital Cost Consumer Benefit - Cost of Service

	Without Wholesale Competition	With Wholesale Competition	Consumer Benefit
Fuel (Fossil and Nuclear)	165,998	156,971	9,027
+ Variable O&M	21,144	19,515	1,630
+ Competitive Energy Purchase	-	11,495	(11,495)
+ Competitive Capacity Value	-	2,220	(2,220)
+ Fixed O&M	5,981	-	5,981
+ Depreciation	1,152	-	1,152
+ Property Taxes	401	-	401
+ Income Taxes	1,448	-	1,448
+ Operating Income	3,435	-	3,435
Operating Expenses (millions $)	199,559	190,200	**9,359**

SOURCE: Global Energy.

Section Two

Wholesale Competition Dramatically Improved the Efficiency of Power Plants

2
Wholesale Competition Dramatically Improved the Efficiency of Power Plants

Global Energy conducted an analysis and review of the North American generation fleet operations to assess improvements and efficiencies attributable to competitive forces. This analysis was based on a study period of 1999-2004. 1999 was selected as a starting period because it was representative of the maturation of restructuring in many parts of the country. Two factors influenced this as a starting point:

- With the passage of EPAct, Congress opened the door to wholesale competition in the electric utility industry by authorizing FERC to establish regulations to provide open access to the nation's transmission system. FERC's subsequent rules, issued in April 1996 as Order 888, facilitiated increased wholesale competition.
- In an effort to continue the evolution of competitive wholesale power markets, FERC Order 2000, released in December 1999, requested the formation of regional transmission organizations further facilitating competition.

Global Energy uncovered strong evidence indicating the electric utility industry has improved its operations and efficiencies largely because of competitive forces. Some of the power plants with great gains in efficiency had been auctioned off by their prior owners as relatively poor performers. But the skill of experienced fleet operators; the standardization of procedures and maintenance; and the combined buying power of fuel, equipment, and supplies have produced dramatic improvements in capacity factors and plant performance. The cost savings and energy efficiency resulting from reduced refueling outages, improved load factors and reliability continues to substantially benefit consumers.

The analysis focused on the nuclear and coal-fueled generating units for traditional and competitive operators. Traditional operators are best defined as investor-owned utilities, municipalities, and cooperatives that are subject to retail rate regulation. Competitive operators are best defined as independent power producers and other generators that are not subject to rate regulation.

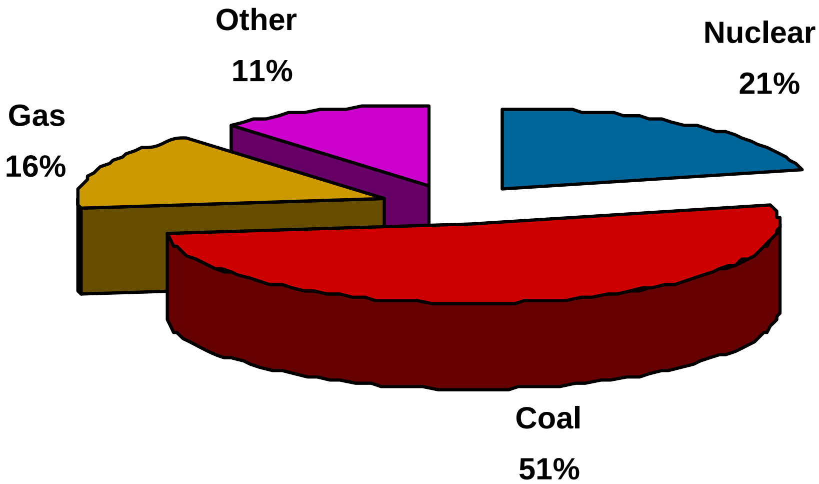
Global Energy Intelligence's **Energy Velocity™** database was the main data source utilized. Energy Velocity provides a comprehensive view of the power market. It combines all the data on the electric industry with complete coverage on IOUs, municipal utilities, generation and transmission cooperatives, distribution cooperatives, non-regulated market participants, and generating assets. Energy Velocity collects information from Global Energy primary research, websites, state and federal agencies, EIA and NERC ES&D. Unit level information is available for existing and planned plants in the United States, Canada, and Mexico.

All cost information reported in this section has been adjusted for inflation using the chained consumer price index for energy.

Nuclear Generation

Nuclear generation makes up 10 percent of the U.S. installed power generation capacity by fuel and about 20 percent of actual net generation each year.[1] Figure 2-1 shows the generation mix for the industry at the end of 2004.

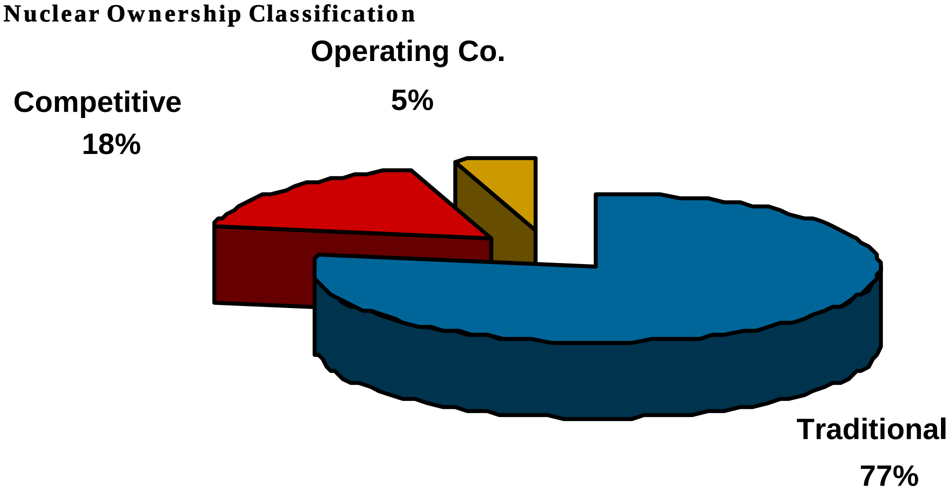
Figure 2-1
2004 Generation Mix



SOURCE: Global Energy.

Nuclear operations are a significant influence on the cost of electricity for the consuming public. Electric utility restructuring led to the consolidation of nuclear operations through the purchase and sale of nuclear facilities across the country by experienced nuclear fleet operators such as Exelon and Entergy. These sales most likely would not have occurred had this flexibility not existed. Global Energy's analysis focused on a view of the nuclear generation based on the classifications in Figure 2-2 where traditional represents plants owned and operated by IOUs and competitive plants that were sold and purchased. For purposes of the study we did not evaluate plants operated by an outside source.

Figure 2-2
Nuclear Ownership Classification



SOURCE: Global Energy.

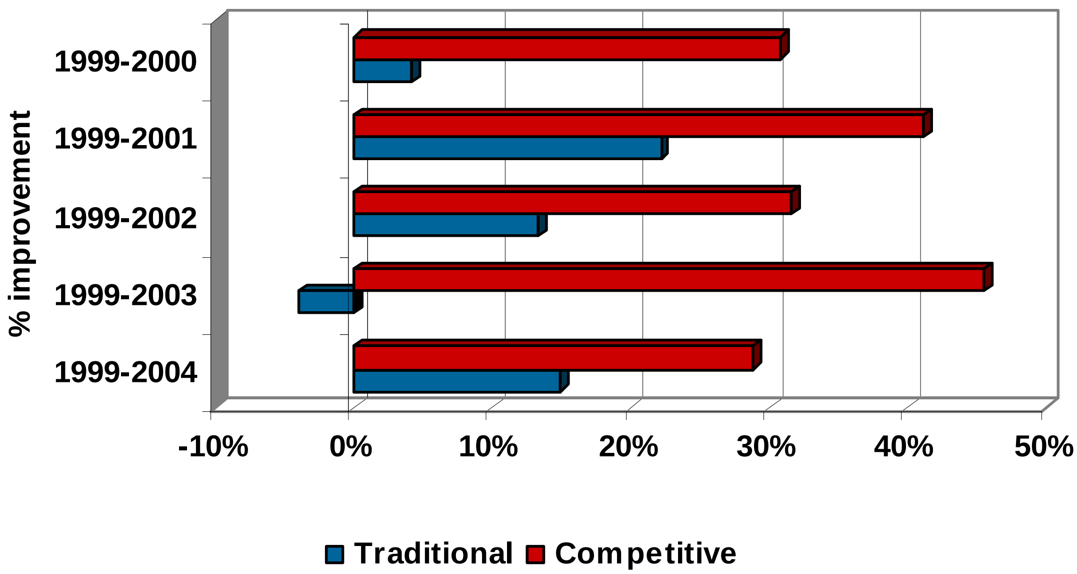
[1] Global Energy Reference Case.

A number of nuclear facilities in the competitive category were considered “troubled” and in danger of being shut down and decommissioned. Under competitive market conditions, many of these nuclear power plants have been sold or their operation was contracted out to experienced nuclear fleet operators on a merchant basis. Consumers have benefited from the continued operation of these units in addition to the improvements in operation and efficiencies.

Nuclear Refueling Outage Time Reduced

Global Energy conducted an analyses and review of the Nuclear Regulatory Commision (NRC) daily unit outage information. In this review of information Global Energy ascertained whether the outage was related to a refueling and aggregated the length of the outages for the study period by year. Competitive units experienced a 26 percent reduction in the length of refueling outages since 1999. They have also displayed significant and continual improvement over the study period as displayed in Figure 2-3. Figure 2-3 depicts the percentage improvement.

Figure 2-3
Percent Reduction in Length of Refueling Outages since 1999



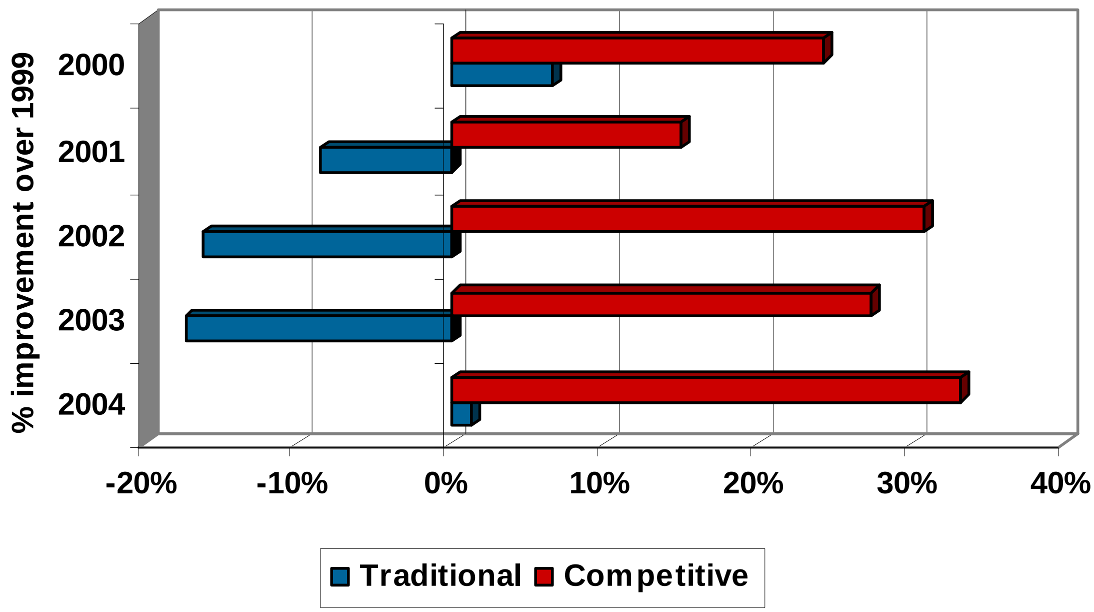
SOURCE: Global Energy.

Traditional nuclear units experienced a 4 percent decline in 2003 over 1999 representing a total of 75 days. This was mainly due to extended outages at approximately 10 facilities. Overall the industry experienced a decline in total refueling outage days of nearly a year. Competition and industry restructuring of the industry have positively influenced the management of nuclear facilities through competitive pricing.

Nuclear Operations and Maintenance Expenses Lowered

Global Energy conducted an analysis of the nuclear facilities total fixed and variable operations and maintenance expense. These costs were reviewed in total. Classification of fixed and variable is somewhat subjective and not consistently reported in the industry. Competitive units experienced a 33 percent reduction in O&M expense on a $/MWh over 1999. Figure 2-4 is a comparison of expense increases/reductions experienced since 1999 for both traditional and competitive nuclear operations adjusted for inflation. Competitive facilities have consistently reduced expenses over the study period.

Figure 2-4
Nuclear O&M Reductions since 1999



SOURCE: Global Energy.

Note that in 1999 competitive nuclear facilities were experiencing a cost of almost $15/MWh whereas traditional facilities cost were slightly more than $10/MWh. This disparity is largely due to the fact that the competitive fleet of nuclear plants had a higher cost structure prior to their transfer to, or acquisition by, the Competitive sector. However, by 2004, the skill of experienced fleet operators; the standardization of procedures and maintenance; and the combined buying power for fuel, equipment, and supplies dramatically improved plant costs and performance. Now the "poor" performers are indistinguishable from traditional facilities, as both have operating and maintenance costs of approximately $10/MWh.

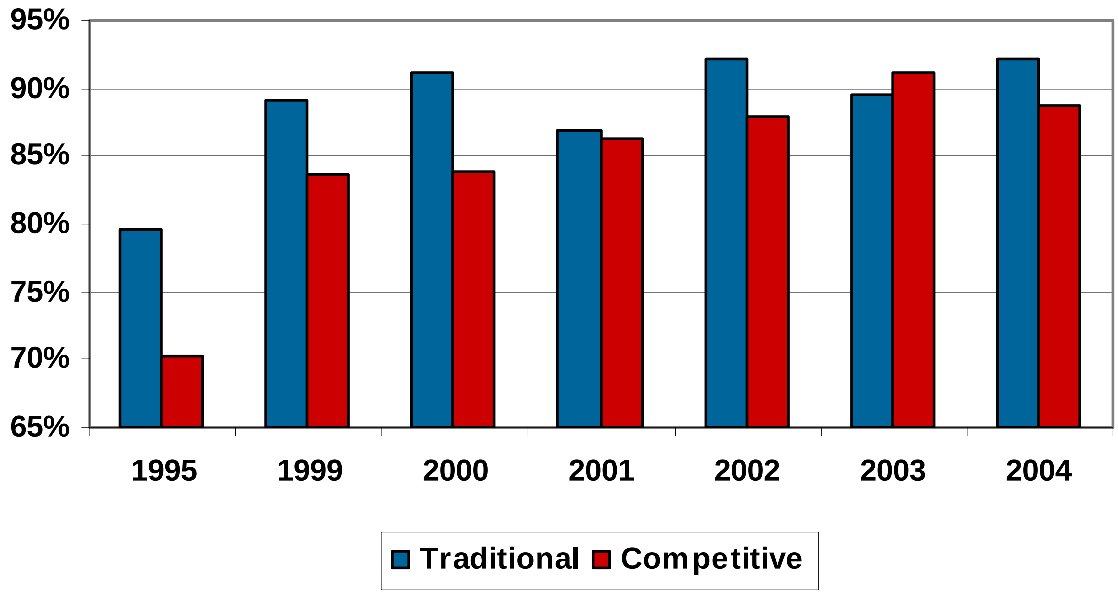
Nuclear Plant Capacity Factors Increased

Nuclear units have relatively low variable costs and thus are low dispatch-cost generating facilities. As such, a measurable benefit is a high capacity factor. It is beneficial for the consumer and operator for these units to operate as much as possible since nuclear generation is considered one of the least expensive forms of generation. One measure of the operation is capacity factor, which is best defined as the percentage of time that a unit is operable. Since nuclear units are "must run" one would expect the percentage of operation to be near 100 percent. However, forced outages, refueling, and maintenance must be performed. Reductions in refueling and maintenance are factors within the operator's control that may be improved. As stated earlier in the report, both refueling and maintenance have improved. Prior to competitive forces shifting the management and operation of nuclear facilities to more experienced operators focused on improving plant performance in a competitive market environment, nuclear facilities were often operating at "sub-optimal" levels in 1995. Since 1995, the nuclear units have displayed continual improvement. According to the Nuclear Energy Institute (NEI), nuclear plants had record output and stable costs in 2004. U. S. plants generated a record 786.5 million MWh in 2004, breaking the 2002 record of 780 million MWh. NEI's figures put the 2004 average net capacity factor at 90.6 percent, trailing only the 91.9 percent achieved in 2002 and 90.7 percent in 2001.

The nuclear industry experienced a 17 percent increase in capacity factors since 1995. Global Energy also found that since 1995 the increase in capacity factor resulted in enough energy to power more than 10 million residential households for one year.[2]

Figure 2-5 depicts capacity factors for the study period for both traditional and competitive facilities.

Figure 2-5
Nuclear Capacity Factors; 1995-2004



SOURCE: Global Energy.

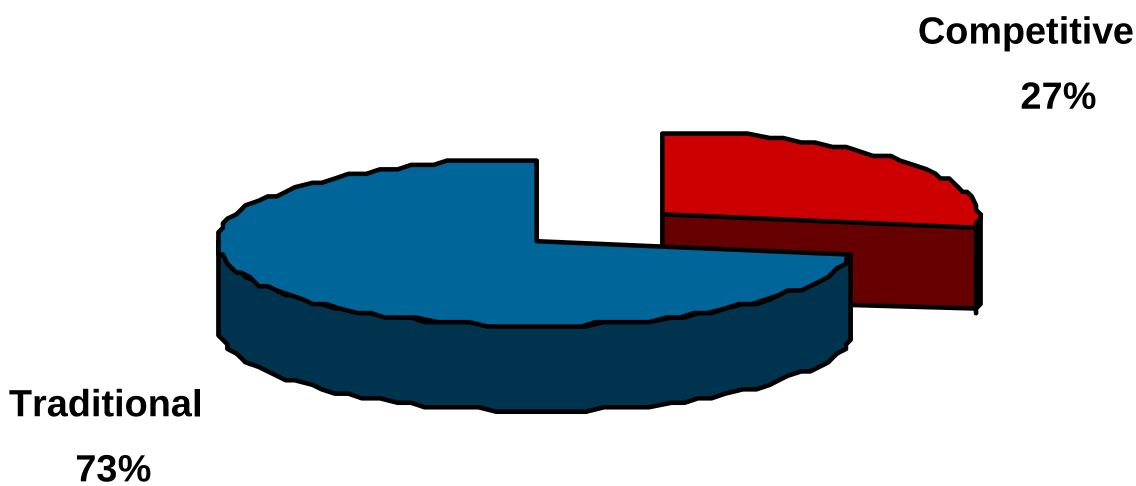
[2] Based on average residential customer annual usage of 10,803 kWh per year.

Coal Generation

Coal-fueled generation is the most predominant type of generating resource in the United States. Even with the additional natural gas-fueled generation, coal still represented 51 percent of total net generation in 2004 as shown in Figure 2-1. Coal-fueled facilities have also benefited from restructuring. As the industry moves away from vertically integrated utilities to non-regulated independent power producers competitive pressures have forced regulated entities to improve operations.

To identify how competitive pressures affected coal generation, Global Energy conducted an analysis of coal-fueled generation based on a classification of traditional and competitive utility structures. Traditional utility structures represent generating facilities owned by investor-owned utilities, municipalities, and cooperatives that are subject to retail rate regulation. Competitive industry structures represent generating facilities owned by independent power producers that are not subject to retail rate regulation. Figure 2-6 shows the percentage of generation from each classification.

Figure 2-6
Coal Plant Generation

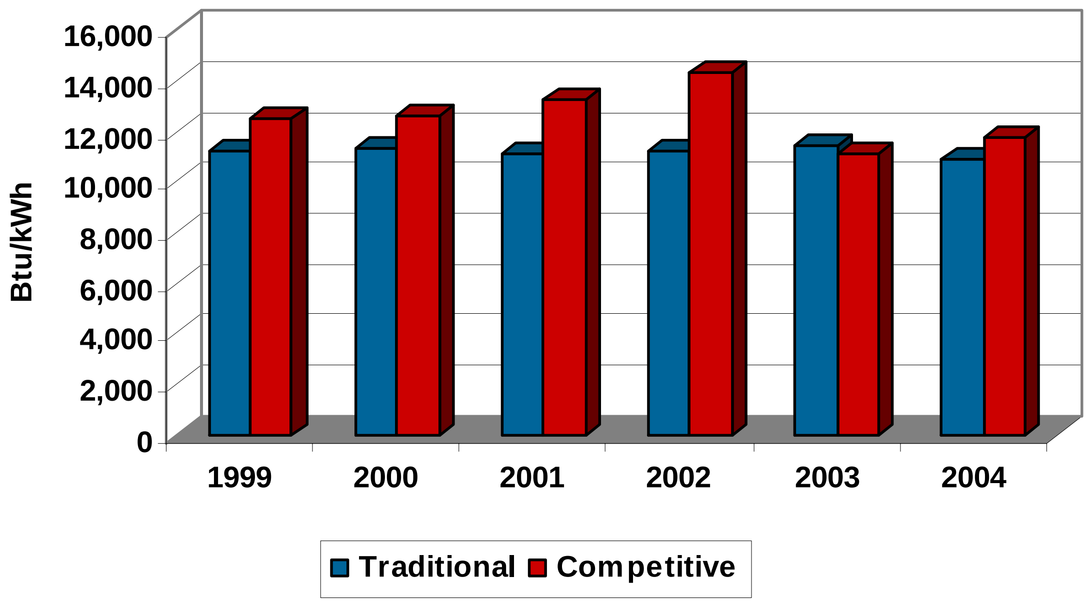


SOURCE: Global Energy.

Coal Heat Rates Improved

Heat rate is a measurement of a generating station's thermal efficiency and is usually expressed in Btu/kWh; the lower the Btu/kWh the higher the efficiency of the unit. Global Energy analyzed coal-fueled units across the United States and evaluated the efficiencies for traditional and competitive units. The traditional units consist of a more modern fleet, while the competitive units are older, less-efficient performers before they were transferred or sold by the prior owners. Nevertheless, the new competitive owners were able to achieve a 6 percent heat rate improvement. The environmental impact of the heat rate improvement is 12.3 million fewer tons of coal burned each year for the competitive fleet. Figure 2-7 shows that competitive units improved heat rates by 6 percent while traditional improved 3 percent since 1999. Overall, industry-wide heat rates for coal plants improved 4 percent during the study period.

Figure 2-7
Coal Heat Rate Improvements



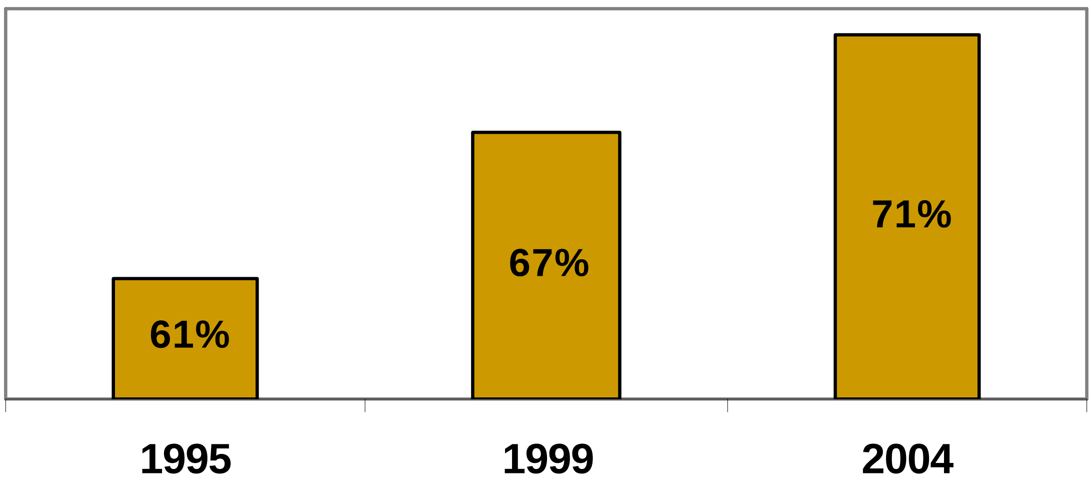
SOURCE: Global Energy.

The reduction in competitive units is attributable to efficiencies being realized in the operation of the units and not retirements. The competitive fleet retired approximately 1,000 MW since 1999 with the average unit size being about 30 MW and an average heat rate of 12,185 Btu/kWh. The traditional fleet retired over 2,500 MW with an average size unit of 55 MW, nearly double the size of units retired by the competitive fleet.

Coal Plant Capacity Factors Increased

As with nuclear plants, the fleet of coal plants saw an improvement in capacity factors in the decade between 1995 and 2004. Figure 2-8 demonstrates that coal-fueled power plant capacity factors increased overall by 16 percent from 61 percent to 71 percent. Because there are three times as many MW of coal-fueled capacity as there are MW of nuclear plant capacity, this increase had the effect of making at least another 50,000 MW of effective generating capacity available for dispatch in 2004 as there was prior to 1995. Furthermore, the increase in capacity factors for coal-based plants was enough electricity to power 25 million residential households for a year.

Figure 2-8
Coal Plant Capacity Factors; 1995-2004



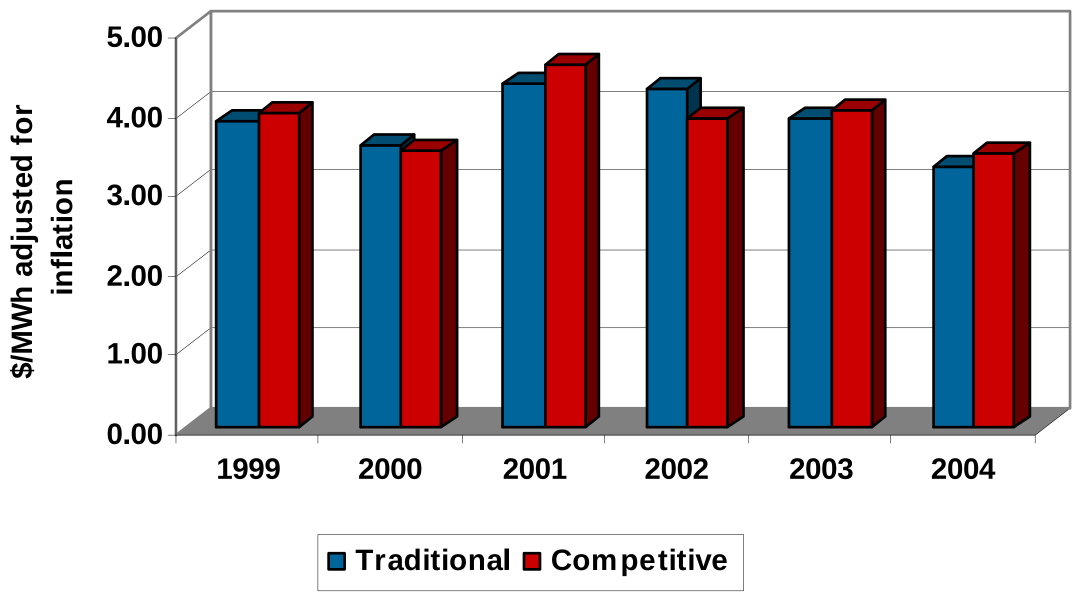
SOURCE: Global Energy.

The competitive generation fleet consists of older and smaller units which results in higher overall heat rate levels. Competitive coal fleet's median size is 474 MW compared to 669 MW for traditional units. Competitive pressures have compelled traditional utilities to maintain costs while improving their overall efficiency. Consumers benefit from the overall improvement in efficiencies of coal generation regardless of whether they are related to traditional or competitive facilities. During the study period, utilities have either switched fuels or installed clean air equipment to comply with SO_2 regulations. All of these actions generally increase heat rates and yet improvements were recognizable overall.

Coal Operations and Maintenance Expenses Declined

Global Energy conducted an analysis of the coal fleet's operation and maintenance expense to ascertain any influences of competition on these costs. Overall coal O&M expense has declined when adjusted for inflation. Figure 2-9 shows that fixed and variable O&M expense based on a $/MWh has declined by 14 percent since 1999 for the industry. Competitive facilities improved 13 percent while traditional experienced a 15 percent improvement.

Figure 2-9
Coal O&M Improvements



SOURCE: Global Energy.

Reductions in the operating costs of base load, lower-cost plants, such as coal, benefit consumers through lower purchased power costs and regulated entities' ability to manage costs such that increases in rates are not necessary.

Overall Observations

The empirical evidence indicates that the electric utility industry has improved its operations and efficiencies. Competitive utility structures are at the forefront of these improvements either directly or indirectly, as demonstrated by the dramatic change in operating performance.

Overall nuclear operations and improvements best display the "direct" effects of competitive structures. As mentioned previously in the report, most of the units considered as competitive were previously in danger of being decommissioned and shut down. These albatrosses around the neck of a utility operator became star performers for the Regulated and Competitive plant operators skilled in running a fleet of nuclear plants. These units have a direct impact on the consumer through their continued and much improved operations.

The overall coal generation fleet has displayed improvements in cost and efficiency. The lines of contribution between traditional and competitive are not as clear cut as nuclear operations. One must think in the realm of previous traditional operations in that the mind set was to "throw money" at the operation of these units and pass it through to consumers. With the advent of competition, the players in the industry were no longer incented to continue with this mind set and thus the turnaround in the efficiency and operations of the coal generation fleet. The competitive structure has clearly imposed pressures resulting in these improvements.

Refer to Appendix C for supporting information.

Section Three

Impact of Regional Transmission Organizations (RTO)

3
Impact of Regional Transmission Organizations (RTOs)

Introduction

To test the impact of competition in expanded wholesale power markets, Global Energy assessed the impacts of integrating Commonwealth Edison (ComEd), American Electric Power (AEP), and Dayton Power & Light (DPL) into the PJM regional power market. The results of the analysis were that the benefits of expanding the PJM wholesale power market in 2004 produced $85.4 million in annualized production cost savings to wholesale customers in the Eastern Interconnection.

These savings were achieved through reduced transmission barriers, or seams, and the entry of new competitors to the market. FERC decisions had enabled additional market participants such as Exelon's ComEd, AEP, and DPL to join the PJM market. The results of competitive forces at work was immediate sending price signals throughout the broader regional power markets where power buyers searching for the lowest-cost supply available found them from a now wider universe of generators, marketers, and suppliers.

PJM Case Study

While wholesale power markets have been functioning in the United States several decades, they continue to evolve. This evolution has been driven primarily by FERC's Standard Market Design process and FERC's goal to see Regional Transmission Organizations (RTO's) formed throughout the United States. The objective of this Case Study was to identify a recent example of markets integrating into a single RTO and determine whether or not the market integration provided consumer benefits.

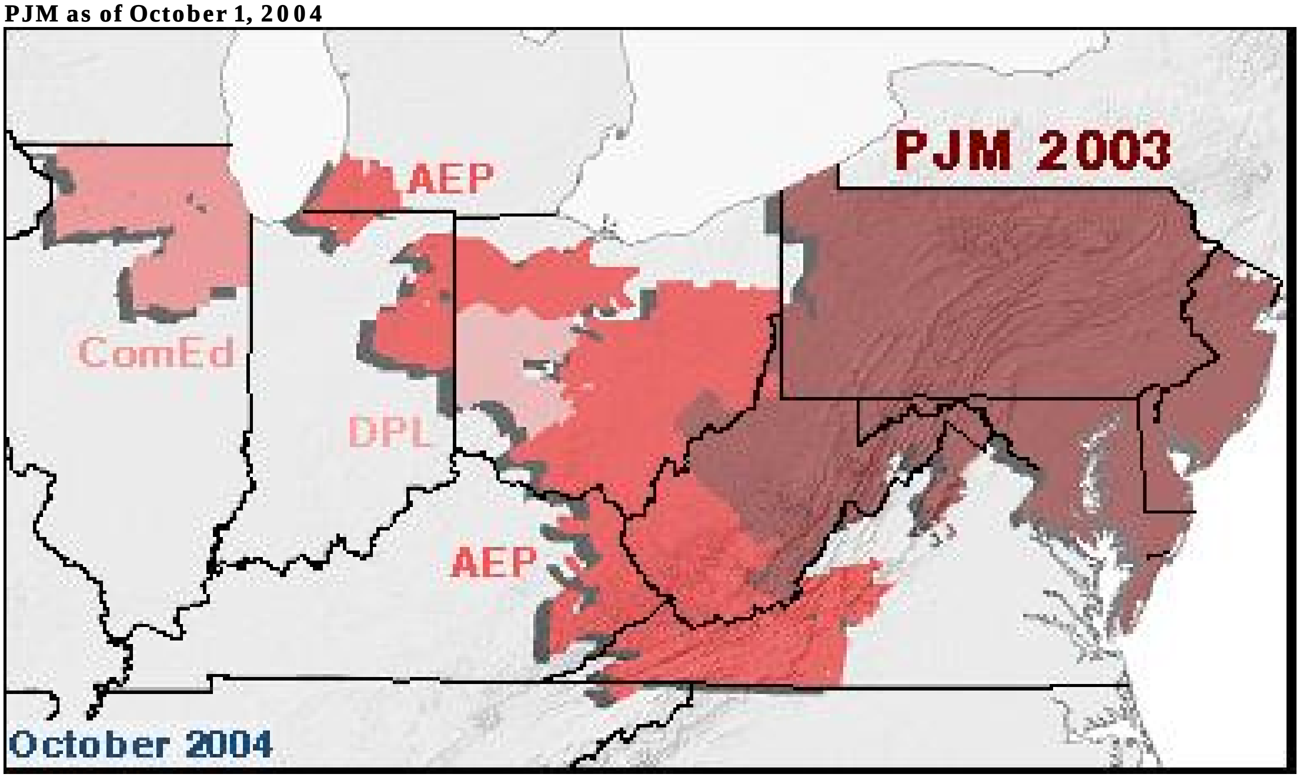
The PJM Interconnect in 2004 proved an excellent subject for this Case Study. Global Energy chose the PJM Interconnect in 2004 for several reasons. First, ComEd, AEP, and DPL joined PJM in 2004, making PJM the largest centrally dispatched, competitive wholesale electricity market in the world. Second, according to an internal analysis performed by PJM, changes in supply and demand fundamentals from 2003 to 2004 translated into lower power prices for PJM.

Global Energy's independent analysis studies the integration of ComEd, AEP, DPL and PJM's energy markets. The results confirmed PJM's conclusions that, in 2004, changes in supply and demand fundamentals resulted in lower PJM prices in 2003 than 2004, and quantified the annualized production cost benefits to PJM customers and the entire Eastern Interconnect at$69.8 million and $85.4 million, respectively.

PJM's Internal Analyisis

The integration of ComEd, AEP and DPL resulted in significant growth in the PJM market. In 2003, PJM comprised of 76,000 MW of installed generating capacity and a peak load of 63,000 MW. By October of 2004, PJM comprised of 144,000 MW of installed capacity and approximately 107,800 MW of peak load.

Figure 3-1
PJM as of October 1, 2004



SOURCE: Global Energy.

According to an internal analysis performed by PJM of the locational marginal prices (LMPs) in its energy spot markets, the impact of supply and demand fundamentals on market behavior from 2003 to 2004 translated into lower power prices for PJM. While average PJM power prices actually increased by 7.5 percent from 2003 to 2004, PJM showed that the increase was primarily a result of higher fuel prices. [1] PJM performed a fuel adjustment of PJM prices and determined that fuel-adjusted PJM power prices actually declined by 4.2 percent from 2003 to 2004.

Table 3-1
PJM Load-weighted LMP ($ per MWh); 2003-2004

	2003	2004	Change
Average LMP	$41.23	$44.34	7.5%
Fuel Adjusted LMP	$41.23	$39.49	-4.2%

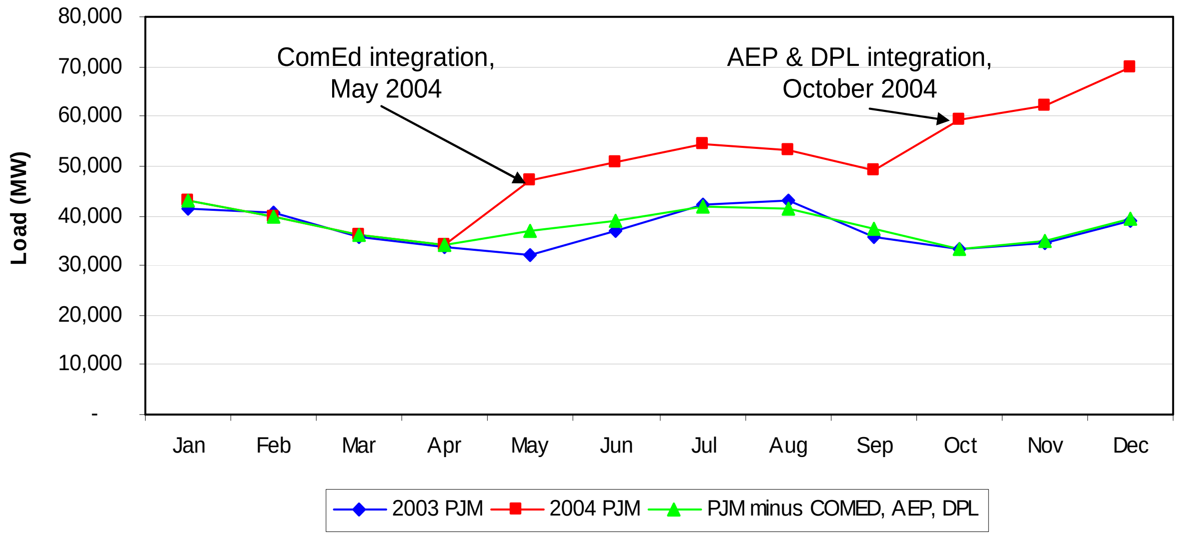
SOURCE: PJM.

[1] The PJM power prices referenced here are load-weighted average power prices. The simple, hourly average PJM LMP was 10.8 percent higher in 2004 than in 2003, according to PJM.

PJM's Assessment of the Supply & Demand

PJM attributed the lower fuel-adjusted power prices to an energy market relatively long on supply, combined with moderate demand, a condition driven primarily by the integration of ComEd into PJM. AEP and DPL joined PJM after the critical peak summer months and their impact on supply and demand was less significant in 2004. On the supply side, during the June-to-September 2004 period, PJM energy markets received a maximum of 109,600 MW in supply offers (net of real-time imports or exports). The 2004 net supply offers represented an increase of approximately 29,800 MW compared to the comparable 2003 summer period. On the demand side, the PJM system peak load in 2004 was 77,887 MW, a coincident summer peak load reflecting the Mid-Atlantic region, the APS control zone, and the ComEd control area. The PJM peak load in 2003 of 61,499 MW occurred prior to the integration of the ComEd control area.

Figure 3-2
PJM Average Monthly Loads; 2003-2004



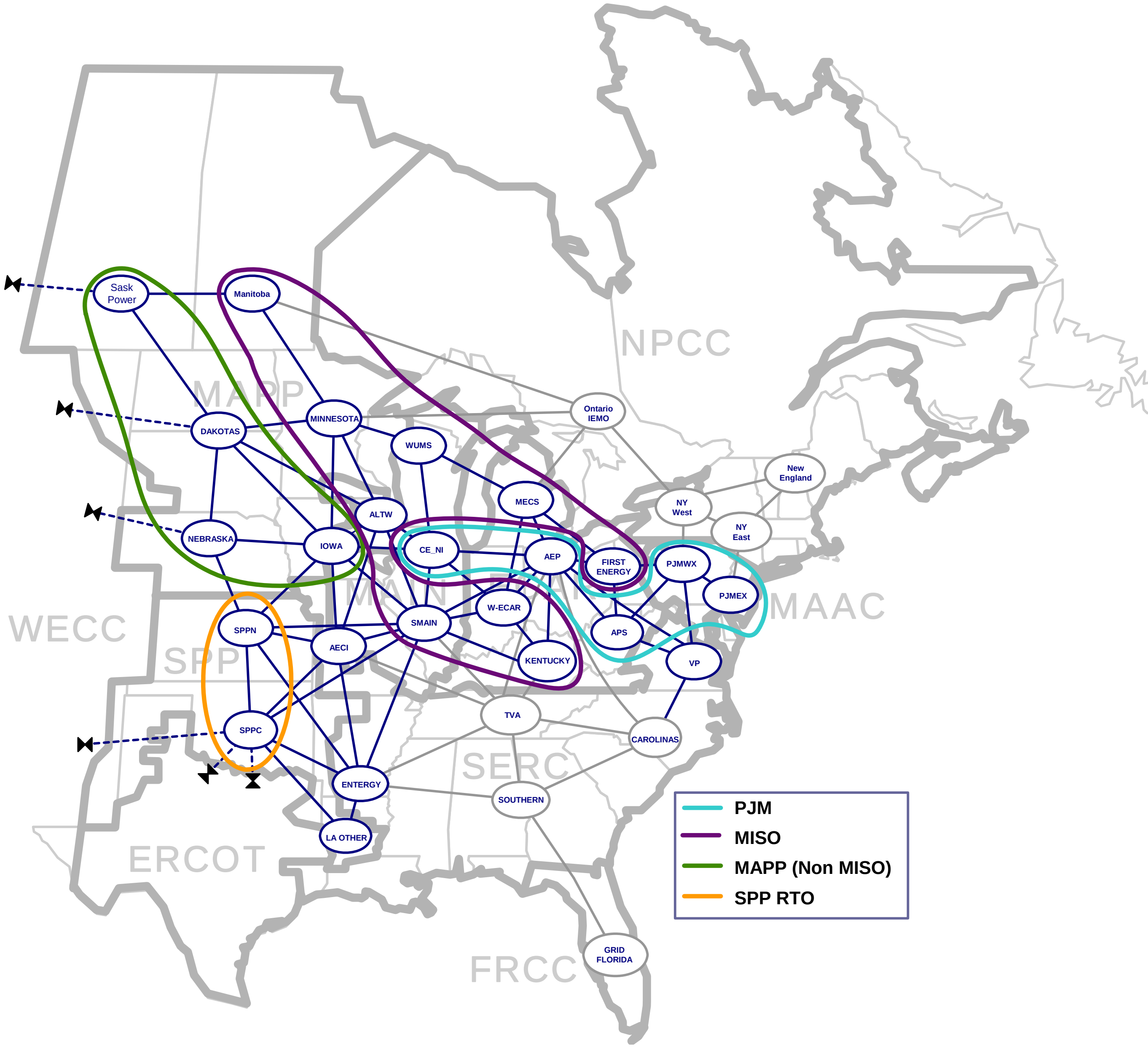
SOURCE: Global Energy.

Global Energy's PJM Case Study Approach

For this case study, Global Energy performed a fundamental Eastern Interconnection market simulation to test PJM's conclusions, account for all price determinants not directly related to the integration, and to quantify the impacts associated with the integration of ComEd, AEP, and DPL supply and demand with that of PJM. Global Energy's approach was to analyze and quantify the impact of reducing the seams, in the form of pancaked wheeling charges, between the ComEd, AEP, DPL and PJM energy markets. By isolating pancaked wheeling charges in its analysis, Global Energy captured the primary structural change to ComEd, AEP, DPL and PJM's energy market supply and demand.

Global Energy employed a production cost savings model using its **EnerPrise™ Market Analytics** *powered by PROSYM®* module, which measures production costs, such as fuel and operations and maintenance costs. The study compared the production costs of a "Competition Case" which simulated PJM as it was in 2004 and compared these costs to a "Without Competition Case" in which the 2004 market as if ComEd, AEP, and DPL never joined PJM. The study included the entire Eastern Interconnect. Because Dominion Resources in Virginia did not joint PJM until January 1, 2005, it is not included in this analysis.

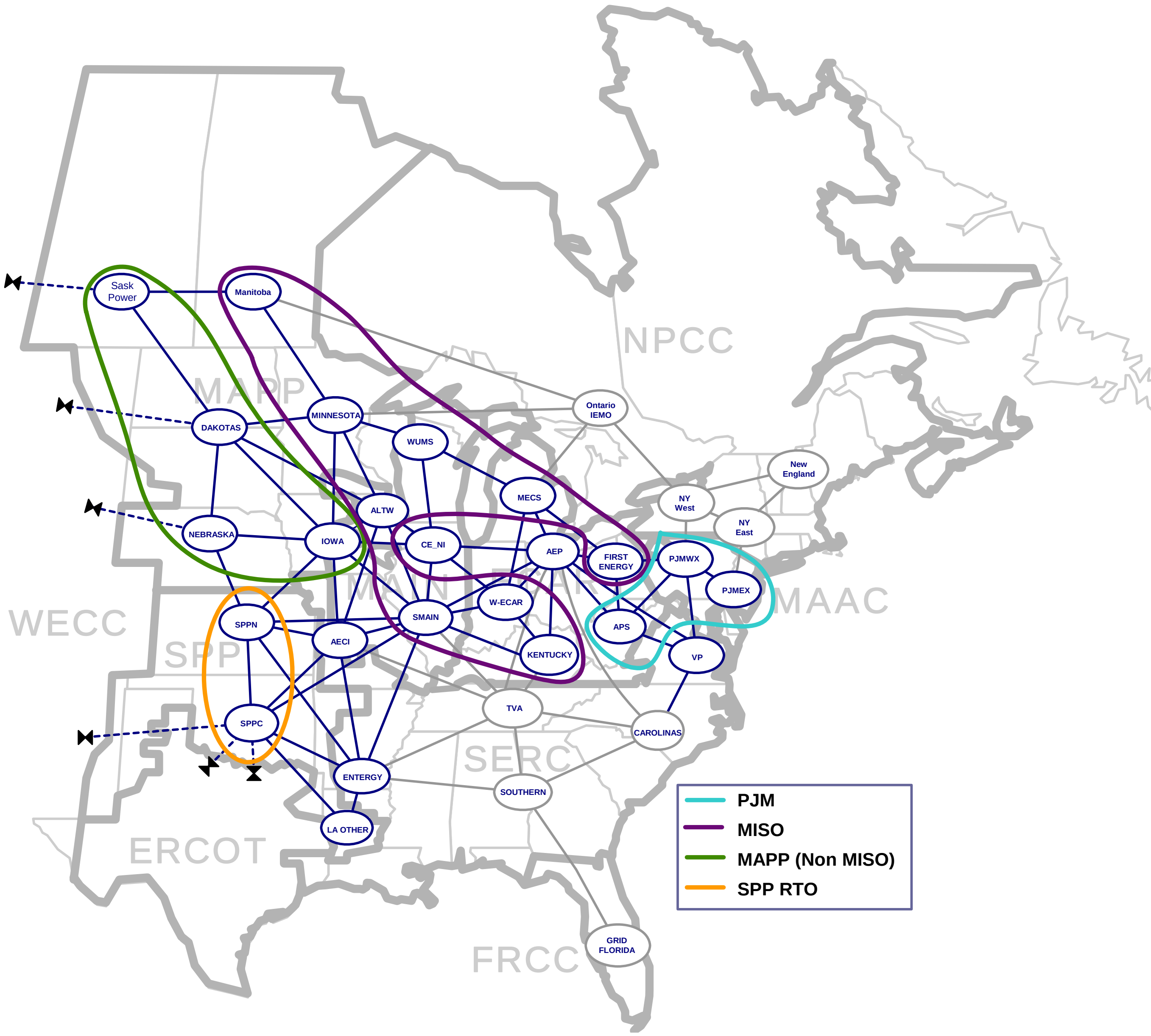
Figure 3-3
Competition Case Market Topology as of October 1, 2004



SOURCE: Global Energy.

In the Without Competition case, the market topology is similar to the Competition case except that ComEd (represented by the CE_NI zone) and AEP and DPL (both represented by the AEP zone) are modeled outside the PJM RTO and pancaked wheeling between the zones is not eliminated.

Figure 3-4
Without Competition Case Market Topology for 2004



SOURCE: Global Energy.

Other Potential Benefits of PJM Integration

In addition to the integration of supply and demand in the wholesale energy market, brought about by the reduction of seams between market areas, there are other significant benefits to RTO membership and the integration of energy markets and services in general that were not considered in this study. For example, AEP and DPL are now integrated with APS in a single spinning reserve market. For regulation services, ComEd, AEP, DPL, and APS are all members of PJM's integrated Western Zone. PJM also coordinates generation and transmission maintenance for the entire RTO as well as Available Transmission Capacity (ATC). These and other potential benefits are not captured in this analysis.

Results Summary

Global Energy's analysis supports PJM's conclusion that, in 2004, changes in supply and demand fundamentals resulted in lower PJM prices in 2004 than 2003. Global Energy quantified the production cost savings associated with the reduction of seams between these ComEd, AEP, DPL and PJM's energy markets at approximately $29.5 million for PJM in 2004 and $36.4 million for the Eastern Interconnection. Because these savings are based on the actual integration schedule for ComEd (May 2004) and AEP/DPL (October 2004), they represent savings for a partial year of integration in 2004. In order to quantify the benefits associated with a full year of integration, Global Energy performed the analysis as if ComEd, AEP, and DPL joined PJM on January 1, 2004. The estimated annualized production cost savings for PJM and the Eastern Interconnection were $69.8 million and $85.4 million, respectively.

Table 3-2
Estimated Benefits of Energy Market Integration in 2004

2004 Production Cost Savings		
Market Area	**Savings based on 2004 PJM Integration Timeline (ComEd in May 2004 and AEP/DPL in October 2004)**	**Annualized Savings (Simulates Integration of ComEd, AEP, DPL on January 1, 2004)**
PJM	$29.5 MM	$69.8 MM
Eastern Interconnect	$36.4 MM	$85.4 MM

SOURCE: Global Energy.

RTO formation has opened the doors to broad market access for customers, not only to merchant generators and suppliers, in a more competitive market environment but also increasingly to renewable energy from wind and other sources. The annual production cost savings for the PJM expansion should continue year after year.

Appendices

Appendix A
Competition in U.S. Wholesale Power Markets

Background

Overview of Electricity Market Restructuring in the United States

The U.S. electric power industry has undergone significant changes in the past several decades, trending from a vertically integrated and cost-regulated industry toward restructured markets with competitive, market-based prices. The transition began in the 1970s when support for traditional utility regulation diminished as a result of increasing electricity prices. The passage of the Public Utility Regulatory Policies Act (PURPA) in 1978 made it possible for non-utility generators to enter the wholesale power market. PURPA was followed by the Energy Policy Act in 1992, and subsequent federal and state legislation with the goal of establishing a regulatory framework in support of competitive wholesale power markets. This section provides an overview of key federal legislative and regulatory initiatives that comprise the regulatory history of the U.S. Electric Power Industry since 1935.

Federal Power Act of 1935

The Federal Power Act (FPA) of 1935 established the guidelines for federal regulation of public utilities engaging in interstate commerce of electricity. Through this act, the Federal Power Commission (FPC) was given wider authority and became the precursor to FERC. Authority given to the FPC included the ability to:

- Issue licenses for new hydroelectric projects;
- Collect utility operational and financial data, including original investment costs and electric generation and sales data; and
- Review electric rates charged by utilities and establish their depreciation schedules.

One of the most important implications of the FPA was the requirement for utilities to charge "fair and reasonable rates." By forcing utilities to publish all rate schedules for public and government review, the FPA forced utilities to defend all rates on a cost of service basis. Charging different rates to customers became illegal, absent substantial cost justification. Further, FPA established the allowable time frame for utilities to change rate schedules.

The FPA of 1935 also outlined strict conflict of interest rules for officers and directors of public utilities engaging in interstate commerce. The FPC was terminated in 1950 when its powers were transferred to FERC. Later, some of FERC's powers were assumed by the U.S. Department of Energy.

Public Utilities Holding Company Act of 1935

Another act passed in 1935 was the Public Utilities Holding Company Act (PUHCA). Designed to work in tandem with the FPA of 1935, PUHCA sounded the death knell for the multi-tiered holding company structures, which had prevented effective regulation of public utilities, and forced utilities operating in more than one state to be heavily regulated by the Securities Exchange Commission (SEC). As a result of PUHCA, most utilities operate within a single state (or in multiple states with a contiguous service territory), which allows them exemption from a great deal of the oversight administered by the SEC.

Prior to this legislation, the U.S. electric industry had experienced significant consolidation, to the extent that only three companies controlled 45 percent of the U.S. electric market. While many states had public utility commissions, none of these agencies had significant regulatory power, especially when pitted against companies involved in commerce across state lines. Because of the lack of regulatory oversight, holding companies were able to legally buffer themselves from government regulation by separating themselves from their operating subsidiaries through multiple layers of holding companies, aligned through complex affiliate relationships. The result was that a few holding companies enjoyed substantial market power and could not be held accountable for engaging in collusive pricing strategies.

PUHCA (and FPA of 1935) was a direct result of negotiations between utility holding companies and the federal government. Utility owners agreed to provide reliable service at a regulated rate, in exchange for an exclusive service territory. Rate regulation would be the responsibility of the Federal Power Commission as established under the FPA of 1935, while the majority of inter-company financial transactions would be regulated by the SEC as outlined in PUHCA. Also, PUHCA dismantled the multi-tiered holding company structure by making it illegal to be more than twice removed from operating subsidiaries.

As a result of PUHCA, over a third of holding companies owning electricity and natural gas distribution utilities were forced by the SEC to divest such that their electric and gas services were no longer affiliated. The legislation allowed exemption from PUHCA if the holding companies operate in a single state or within contiguous states. While most holding companies have chosen to operate within a single state to qualify for PUHCA exemption, these firms are still strictly regulated by state public utility or public service commissions.

Public Utility Regulatory Policies Act – 1978

PURPA is one of five bills signed into law on November 9, 1978, as part of the National Energy Act. It is the only one remaining in force. Enacted to combat the “energy crisis,” and encourage the development of alternative sources of generation, PURPA requires utilities to buy power from non-utility generating facilities that use renewable energy sources or “cogeneration,” i.e., the use of steam both for heat and to generate electricity. A non-utility generating facility that meets certain ownership, operating, and efficiency criteria established by FERC is known as a Qualifying Facility or QF. The Act stipulates that electric utilities must interconnect with these QFs and buy the capacity and energy offered by the QFs at the utilities’ avoided cost.

Energy Policy Act – 1992

The Energy Policy Act of 1992 (EPAct) opened access to transmission networks and exempted certain non-utilities from the restrictions of the Public Utility Holding Company Act of 1935 (PUHCA). EPAct therefore made it easier yet for non-utility generators to enter the wholesale market for electricity. While EPAct opened access to transmission networks for purposes of wholesale transactions, it did not mandate open access for retail load. The Act left it up to individual states to determine if they wanted to open access to power lines for purposes of retail sales.

The Act also created a new category of power producers, called exempt wholesale generators (EWGs). By exempting EWGs from PUHCA regulation, the law eliminated a major barrier for utility-affiliated and nonaffiliated power producers wanting to compete to build new non-rate-based power plants. EWGs differ from PURPA Qualifying Facilities (QFs) in two ways. First, they are not required to meet PURPA’s utility ownership, cogeneration, or renewable fuels limitations. Second, utilities are not required to purchase power from EWGs.

In addition to giving EWGs and QFs access to distant wholesale markets, EPAct provides transmission-dependent utilities the ability to shop for wholesale power supplies, thus releasing them—mostly municipals and rural cooperatives—from their dependency on surrounding investor-owned utilities for wholesale power requirements. The transmission provisions of EPAct have led to a nationwide, open-access electric power transmission grid for wholesale transactions.

FERC Order 888 and 889 – 1996

With the passage of EPAct, Congress opened the door to wholesale competition in the electric utility industry by authorizing FERC to establish regulations to provide open access to the nation's transmission system. FERC's subsequent rules, issued in April 1996 as Order 888, are designed to increase wholesale competition in the nation's transmission system, remedy undue discrimination in transmission, and establish standards for stranded cost recovery. A companion ruling, Order 889, requires utilities to establish electronic systems to share information on a non-discriminatory basis about available transmission capacity.

FERC Order 2000 – 1999

In an effort to continue the evolution of competitive wholesale power markets, FERC Order 2000, released in December 1999, requested the formation of regional transmission organizations (RTOs). The reasons for establishing RTOs were to:

- Improve efficiencies in transmission grid management;
- Improve grid reliability;
- Remove remaining opportunities for discriminatory practices;
- Improve market performance; and
- Facilitate lighter handed regulation.

To achieve this end, the order established minimum characteristics and functions for RTOs; a collaborative process for owners and operators of interstate transmission facilities to consider and develop RTOs; a ratemaking reform process; and a schedule for public utilities to file with FERC to initiate RTO operations.

FERC's Standard Market Design Activity, 2001 – Present

Since FERC Order 2000, FERC has released proposed rule makings defining further their position on the formation of RTOs and how wholesale electricity markets should be managed. On March 15, 2002, FERC issued its notice of proposed rulemaking (NOPR) on standard market design (SMD). The purpose of this rulemaking was to establish standards for bulk wholesale market design, focusing on the establishment of RTOs while recognizing the need for flexibility to address regional differences.

Despite FERC's staunch commitment to reliable, efficient, and competitive wholesale markets, SMD has been met with mixed support. While some regions have embraced the establishment of RTOs and the standards proposed in FERC's SMD process, many utilities and state agencies—particularly those in the

South—have been reluctant to form or join RTOs. It appears that U.S. wholesale power markets will continue to be a hybrid of bilateral and/or organized RTO markets for the foreseeable future.

Table A-1
Major Milestones

1996	Order 888	Introduced concept of open access to transmission lines and open access same-time information system (OASIS).
1999	Order 2000	Introduced the concept of regional transmission organizations (RTOs); encouraged but did not require utilities to join.
2001	Price Mitigation Plan	Initial order released on April 26, 2001; applied to California starting May 29, 2001. Order extended to cover 11 western states in the WSCC.
2001	Enron Collapse	November 15, 2001, Enron's problems escalate; bankruptcy filing December 2, 2001.
2002	Supreme Court Ruling	April 4, 2002, the Supreme Court re-affirms FERC's jurisdiction in pushing ahead with its long-term policy to create a seamless national grid.
2002	FERC's Standard Market Design	Issued on March 15, 2002, proposes mandatory, universal rules covering all RTOs/ISOs.

SOURCE: Global Energy.

Defining Competition

The U.S. electric power industry did not develop according to a single plan or business model. Rather, it evolved over time in response to various local and regional needs and requirements. The regulation of the industry also evolved, changing according to local and regional needs and the politics of the time. Therefore, defining competition in the U.S. electric power industry requires a working definition of the industry itself.

It is a challenge to provide a concise definition of the U.S. electric power industry. This is largely due to the history of both the industry and the nation. Since the concept of an electric power industry was, in essence, born in this country, the model followed for the development of the industry has evolved over time.

The industry developed with two fundamentally different forms of electric utility ownership: 1) investor-owned utilities (IOUs), which operate to provide a profit to shareholders; and 2) public power agencies, organized under various governmental authorities at the city, state, and federal level. This ownership distinction has become a crucial issue in the competition debate, as the regulatory jurisdiction over electric utilities is different for these two categories of participants.

Competition is such a common, everyday occurrence in the United States that we rarely ever try to think about what it is. Each day, we make multiple decisions in a competitive environment, trading off price, convenience and quality to decide where to eat lunch, purchase gas, or buy a pair of socks. Most people don't realize it, but when the power industry began just over a century ago, the same competitive situation existed with multiple electric service companies springing up in New York City, each with its own generators and distribution wires. This quickly became cumbersome (and dangerous), and from this developed the idea of the power industry being a "natural monopoly." Cities and other political jurisdictions decided to make electric service a "franchise," giving a single, integrated electric service provider the sole right to serve all retail customers within their borders. Over time, various levels of regulation arose to prevent the electric utilities from charging "unreasonable" prices. Also, retail electricity prices were set, by regulation, at the average cost of service for each class of customer.

Over the last quarter century there has been a cycle in business regulation based on the observation that industries which in the past were perceived to be "natural monopolies" were no longer so, usually due to relatively easier entry for new suppliers, or technological advances that gave buyers better access to competitive alternatives and easier price discovery. Since the 1970s, there has been steady deregulation of many U.S. industries, including natural gas production, natural gas pipelines, railroads, long haul trucking, telecommunications, and airlines.

In the case of the electric power industry, deregulation has occurred in fits and starts, hampered by the multi-jurisdictional nature of regulation itself. Broadly speaking, the power industry has two sectors, a wholesale sector focused on transactions between entities that are not the end users, and a retail sector consisting of the ultimate end users, be they homes, commercial establishments or large industrial consumers. The wholesale sector is regulated by FERC, while the retail sector is regulated by each state's public utility commission. And the public power agencies are often exempt from many regulations.

With the context of the electric power industry now defined, we can start to define what competition means. The definition has wholesale and retail dimensions.

Retail competition occurs at the state or local level and essentially means that individual residential, commercial or industrial customers can choose their electricity supplier. These suppliers are commonly known as competitive retailers or retail electric providers. This study does not include the cost-savings or benefits associated with retail competition.

Wholesale competition occurs at the regional level and is distinguished in two ways. First, wholesale purchasers of supply (e.g. utilities, competitive retailers and other load-serving entities) and wholesale power suppliers (e.g. generators and markers) engage in arms-length negotiations that result in bilateral contracts. This approach is usually for seasonal, medium-term or longer-term supply. Second, wholesale purchasers and suppliers participate in short-term, bid-based spot markets whereby their bids and offers clear the market at various price levels throughout the day. Certain elements of wholesale power competition are shown in Table A-2.

Table A-2
Elements of Wholesale Power Competition

Wholesale Power	
Competitive Elements	**Status**
Entry by new participants	Any company with the financial resources can enter the market and sell electric power.
Access to electric transmission	New generators can get interconnected, but in some cases do not have ability to reach customers.
Functioning markets for wholesale power	Some markets organized by ISOs (ISO-NE, NYISO, PJM, MISO, ERCOT, CAISO), others have active bilateral day-ahead markets. Still others have little liquidity.

SOURCE: Global Energy.

Appendix B
Modeling Tools

EnerPrise™ Strategic Planning *powered by MIDAS Gold®* was utilized to measure and analyze the consumer value of competition.

Strategic Planning includes multiple modules for an enterprise-wide strategic solution. These modules are:

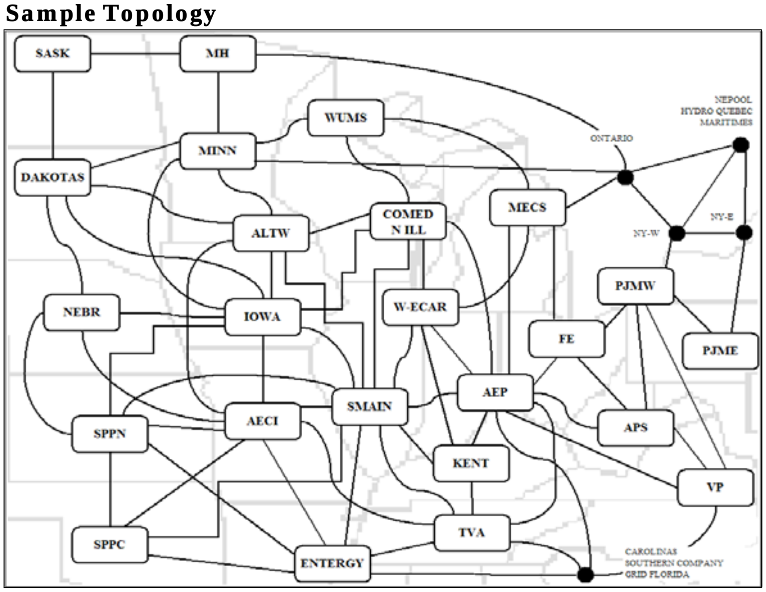
- Markets;
- Portfolio;
- Financial; and
- Risk.

Strategic Planning is an integrated, fast, multi-scenario zonal market model capable of capturing many aspects of regional electricity market pricing, resource operation, and asset and customer value. The markets and portfolio modules are hourly, multi-market, chronologically correct market production modules used to derive market prices, evaluate power contracts, and develop regional or utility-specific resource plans. The financial and risk modules provide full financial results and statements and decision-making tools necessary to value customers, portfolios and business unit profitability.

Markets Module

Markets Module generates zonal electric market price forecasts for single and multi-market systems by hour and chronologically correct for 30 years. Prices may be generated for energy only, bid- or ICAP-based bidding processes. Prices generated reflect trading between transaction groups where transaction group may be best defined as an aggregated collection of control areas where congestion is limited and market prices are similar. Trading is limited by transmission paths and constraints quantities.

Figure B-1
Sample Topology



SOURCE: Global Energy.

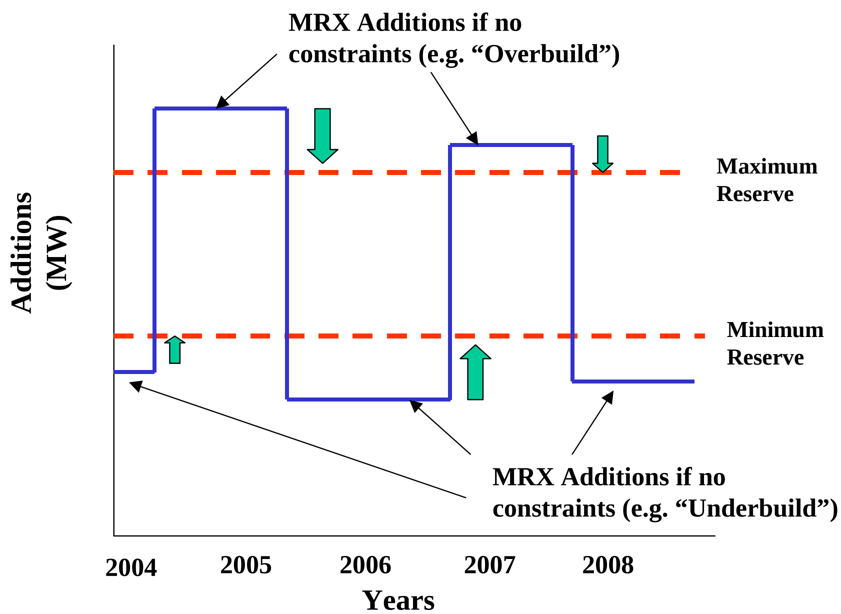
The database is populated with Global Energy Intelligence – Market Ops information.

- Operational information provided for over 10,000 generating units.
- Load forecasts by zone (where zone may be best defined as utility level) and historical hourly load profiles.
- Transmission capabilities.
- Coal price forecast by plant with delivery adders from basin.
- Gas price forecast from Henry Hub with basis and delivery adders.

When running the simulation in Markets Module, the main process of the simulation is to determine hourly market prices. Plant outages are based on a unit derate and maintenance outages may be specified as a number of weeks per year or scheduled.

The market based resource expansion algorithm builds resources by planning region based on user-defined profitability and/or minimum and maximum reserve margin requirements in determining prices. In addition, strategic retirements are made of non-profitable units based on user-defined parameters.

Figure B-2
MRX Decision Basis



SOURCE: Global Energy.

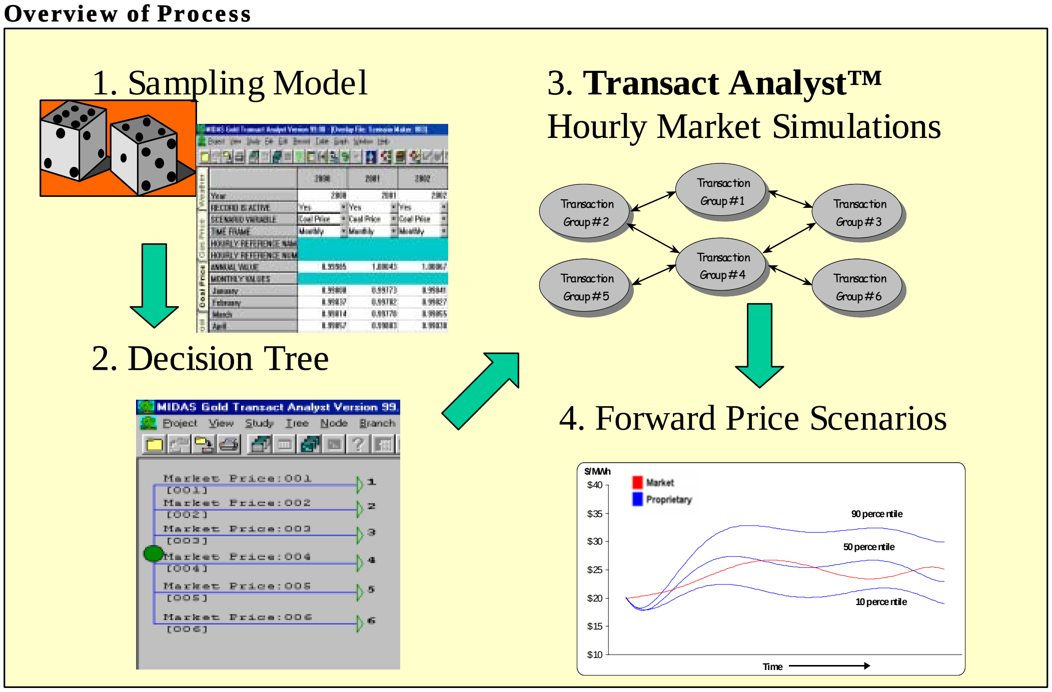
The Markets Module simulation process performs the following steps to determine price:

- Hourly loads are summed for all customers within each Transaction Group;
- For each Transaction Group in each hour, all available hydro power is used to meet firm power sales commitments;
- For each Transaction Group and Day Type, the model calculates production cost data for each dispatchable thermal unit and develops a dispatch order;
- The model calculates a probabilistic supply curve for each Transaction Group considering forced and planned outages;

- Depending on the relative sum of marginal energy cost + transmission cost + scarcity cost between regions, the model determines the hourly transactions that would likely occur among Transaction Groups; and
- The model records and reports details about the generation, emissions, costs, revenues, etc. associated with these hourly transactions.

Strategic Planning has the functionality of developing probabilistic price series by using a four-factor structural approach to forecast prices that captures the uncertainties in regional electric demand, resources and transmission. Using a Latin Hypercube-based stratified sampling program, Strategic Planning generates regional forward price curves across multiple scenarios. Scenarios are driven by variations in a host of market price "drivers" (e.g., demand, fuel price, availability, hydro year, capital expansion cost, transmission availability, market electricity price, reserve margin, emission price, electricity price and/or weather) and takes into account statistical distributions, correlations, and volatilities for three time periods (i.e., Short-Term *hourly*, Mid-Term *monthly*, and Long-Term *annual*) for each transact group. By allowing these uncertainties to vary over a range of possible values a range or distribution of forecasted prices are developed.

Figure B-3
Overview of Process



SOURCE: Global Energy.

Portfolio Module

Once the price trajectories have been completed in the Markets Module, the Portfolio Module may be used to perform utility or region specific portfolio analyses. Simulation times are faster and it allows for more detailed operational characteristics for a utility specific fleet. The generation fleet is dispatched competitively against pre-solved market prices from the Markets Module or other external sources. Native load may also be used for non-merchant/regulated entities with a requirement to serve.

Operates generation fleet based on unit commitment logic which allows for plant specific parameters of:

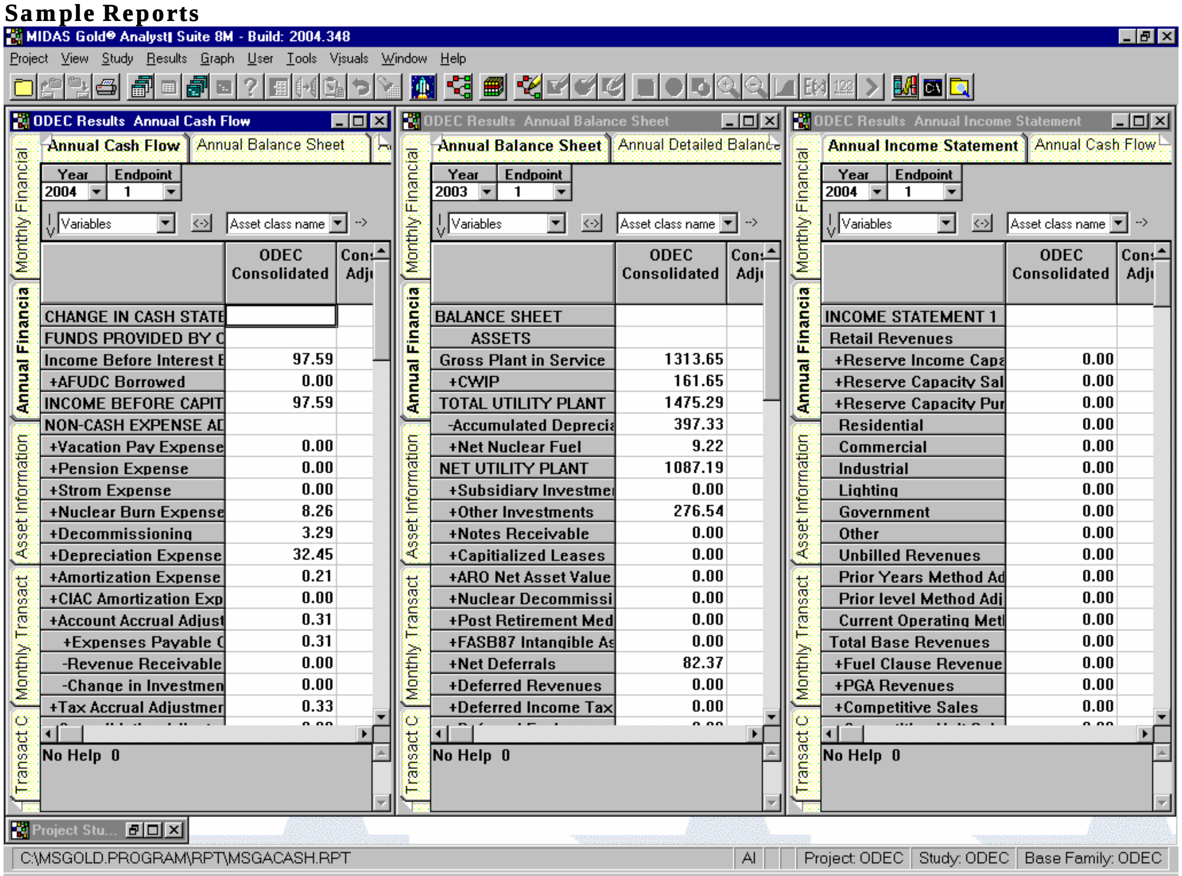
- Ramp rates;
- Minimum/maximum run times; and
- Start up costs.

The decision to commit a unit may be based on one day, three day, seven day and month criteria. Forced outages may be based on Monte Carlo or frequency duration with the capability to perform detailed maintenance scheduling. Resources may be de-committed based on transmission export constraints. Portfolio Module has the capability to operate a generation fleet against single or multiple markets to show interface with other zones. In addition, physical, financial, and fuel derivatives with pre-defined or user-defined strike periods, unit contingency, replacement policies, or load following for full requirement contracts are active.

Financial Module

The Financial Module allows the user the ability to model other financial aspects regarding costs exterior to the operation of units and other valuable information that is necessary to properly evaluate the economics of a generation fleet. The Financial Module produces bottom-line financial statements to evaluate profitability and earnings impacts.

Figure B-4
Sample Reports



SOURCE: Global Energy.

Risk Module

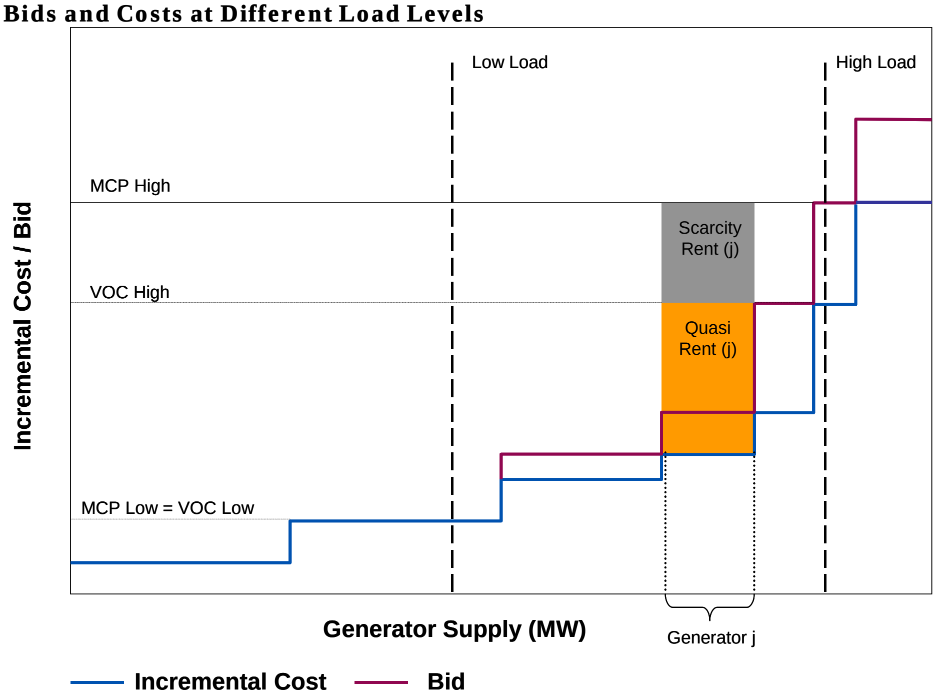
Risk Module provides users the capability to perform stochastic analyses on all other modules and review results numerically and graphically. Stochastics may be performed on both production and financial variables providing flexibility not available in other models.

Bidding Behavior

Power prices are formed each hour, based on the bids submitted by individual generators. In general, the marginal unit determines the market clearing price where a unit's bid includes variable costs such as fuel and variable O&M. In practice, generators employ a wide variety of strategies that are consistent with the cost and load serving characteristics of their generating portfolio. These entities forecast how tight the supply/demand situation is to assess the pricing opportunities in the market, and will price their output in a manner that reflects not only the costs of individual units, but also the cost of operating the entire portfolio, including the most expensive units needed to meet load.

During some of high load hours of the study period, it was observed there was barely sufficient generation to meet loads. At this point, the generator priced electricity at levels above their variable costs. During these times, the revenue collected by individual generators increases with the scarcity present in the market and can, over time, contribute significantly to the coverage of financing and other fixed costs. The collection of scarcity revenue is consistent with a functioning market, providing a price signal to the market that additional resources may be necessary.

Figure B-5
Bids and Costs at Different Load Levels



SOURCE: Global Energy.

Figure B-5 is a graphical representation of how scarcity relates to the supply/demand balance. The lower curve in the diagram represents the variable costs (including incremental fuel costs and variable O&M) for different generators in an hour, stacked from lowest to highest cost.

Baseloaded low cost plants, such as coal and nuclear facilities, have little incentive to bid above their short run marginal costs as they will seldom or never be at the margin (but will nevertheless receive the market clearing price). During low load hours, when there is ample supply relative to load, one might expect generators to be price-takers, bidding their variable operating cost (VOC). The market clearing price is set by the cost of the last unit dispatched. In our example, the second dispatch block sets MCP_{Low} during a low load hour.

As load increases to the point where supply just barely covers load, the scarcity (or rent) increases. As demand increases, there are fewer alternative sources of generation, and the higher cost generators have opportunities to bid above their variable costs. This above-VOC bidding is represented by the upper curve in the figure; price is then set above the costs of the last unit dispatched, as shown by MCP_{High} in Figure B-5 during a high load hour.

Rents are defined as the revenues received by a market participant in excess of that participant's marginal costs. These rents are available to cover both fixed and financing costs (including required returns on equity). Even during low-load periods significant rents may exist. For example, in Figure B-5, the owners of generation in the first block face variable costs below the market clearing price. Unit operating constraints and outages may also result in significant scarcity even during low load hours.

To further illustrate the economic rents collected by a generator, Figure B-5 shows the total rent collected by generator "j." The total rent is the generator's output times the difference between the price and its VOC, or the sum of the two rectangular shaded areas in Figure B-5. The upper rectangular area is what is typically described as the scarcity rent; it reflects the price increase that is due to the ability of the marginal generator to bid in excess of its marginal costs.

Total scarcity rents—which are shared by all generators—are equal to the total generation in the market multiplied by (MCP_{High} – VOC_{High}).

The lower rectangular area is sometimes referred to as quasi-rents—it is a rent that appears even if all participants are acting as price-takers. For the entire market, total quasi-rents are represented as the area above the VOC curve and below the VOC for the marginal dispatch block. Thus, in Figure B-5 it is the area below VOC_{High} and above the VOC curve.

Quasi-rents appear under almost all market conditions. Even in the low-load case, the first dispatch block earns quasi-rents. Quasi-rents are an important source of revenue necessary to pay start-ups, minimum-run costs, fixed operating costs, and the financial expenses associated with generating facilities. However, marginal units do not earn quasi-rents. These units instead depend on scarcity rents resulting from bidding above short run marginal costs to provide the necessary coverage of fixed and financing costs.

Appendix C
Benefits & Efficiency Improvements

Table C-1
Nuclear Plants Purchased/Sold

	Date of Sale
Three Mile Island	December 1999
Clinton	December 1999
Oyster Creek	August 2000
Vermont Yankee	March 2002
Millstone	March 2001
Fitzpatrick	November 2000
Pilgrim	July 1999
Salem	January 2001
Peach Bottom	January 2001
Hope Creek	January 2001
Indian Point	September 2001
Nine Mile Point	November 2001
Seabrook	December 2002
Ginna	June 2004
Kewaunee	Tentative

SOURCE: Global Energy.

Table C-2
Nuclear Plants included in Analysis (2004 MW)

Plant Name	Summer Capacity MW
Arkansas Nuclear One	1,776
Beaver Valley	1,665
Braidwood	2,349
Browns Ferry	2,226
Brunswick (NC)	1,720
Brunswick (NC)	1,631
Byron (IL)	2,412
Callaway (MO)	1,143
Calvert Cliffs	1,805
Catawba	2,258
Clinton (IL)	1,116
Columbia Generating	1,170
Comanche Peak	2,208
Cooper	758
Crystal River	834
Davis Besse	873
Diablo Canyon	2,174

Table continued on next page.

Plant Name	Summer Capacity MW
Donald C Cook	2,078
Dresden	1,700
Duane Arnold	578
Edwin I Hatch	1,726
Fermi	1,111
Fort Calhoun	476
Ginna	498
Grand Gulf	1,210
H B Robinson	683
Harris (NC)	900
Hope Creek	1,131
Indian Point 2	1,040
Indian Point 3	997
James A Fitzpatrick	840
Joseph M Farley	1,675
Kewaunee	574
La Salle	2,259
Limerick	2,268
McGuire	2,200
Millstone	2,064
Monticello (MN)	597
Nine Mile Point (NY)	1,756
North Anna	1,842
Oconee	2,538
Oyster Creek (NJ)	619
Palisades (MI)	779
Palo Verde	3,869
Peach Bottom	2,221
Perry (OH)	1,265
Pilgrim	667
Point Beach	1,012
Prairie Island	1,049
Quad Cities (EXELON)	1,710
Riverbend	980
Salem (NJ)	2,361
San Onofre	2,150
Seabrook	1,161
Sequoyah (TN)	2,239
South Texas	2,529
St Lucie	1,678
Surry	1,625

Table continued on next page.

Plant Name	Summer Capacity MW
Susquehanna	2,301
Three Mile Island	816
Turkey Point	1,386
V C Summer	966
Vermont Yankee	506
Vogtle (GA)	2,297
Waterford 3	1,093
Watts Bar Nuclear	1,128
Wolf Creek (KS)	1,170

SOURCE: Global Energy.

Table C-3
Refueling Outages (Total # of days per year)

	2004	2003	2002	2001	2000	1999
Traditional	1,618	1,978	1,648	1,481	1,822	1,903
Competitive	401	307	386	332	390	564

SOURCE: Global Energy.

As identified from NRC outage reporting and Global Energy's assessment to determine if outage was related to refueling.

Table C-4
Nuclear Fixed and Variable O&M ($/MWh)

Adjusted for inflation	2004	2003	2002	2001	2000	1999
Industry	10.17	11.88	11.69	11.67	9.92	11.09
Traditional	10.03	11.91	11.80	11.03	9.49	10.16
Competitive	9.92	10.77	10.28	12.61	11.25	14.85

SOURCE: Global Energy.

Table C-5
Coal Fixed and Variable O&M ($/MWh)

Adjusted for Inflation	2004	2003	2002	2001	2000	1999
Traditional	3.29	3.89	4.27	4.32	3.54	3.84
Competitive	3.43	3.98	3.88	4.58	3.49	3.96
All	3.33	3.92	4.15	4.39	3.52	3.88

SOURCE: Global Energy.

Table C-6
Coal Operational Statistics

Heat Rate (Btu/kWh)	2004	2003	2002	2001	2000	1999
Traditional	10,885	11,470	11,249	11,136	11,312	11,243
Competitive	11,717	11,067	14,343	13,269	12,599	12,469
All	11,175	11,320	12,467	11,961	11,789	11,680

SOURCE: Global Energy.

Table C-7
Coal Generation Fleet (2004 MW)

Unit Name	Summer Capacity MW
A B Brown	500
Abitibi Consolidated Snowflake	68
ACE Cogeneration Co	101
AES BV Partners Beaver Valley	146
AES Cayuga	306
AES Greenidge	162
AES Hawaii Inc	180
AES Shady Point Inc	320
AES Somerset LLC	684
AES Thames Inc	181
AES Warrior Run Cogeneration F	180
Ag Processing Inc	9
Albright	283
Allen (TN)	738
Altavista	63
Ames (IA AMES)	103
Antelope Valley	904
Argus Cogeneration Plant	50
Armstrong Power Station	343
Asbury	213
Asheville	392
Ashtabula	244
Avon Lake	715
B C Cobb	501
B L England	439
Bailly	480
Baldwin Energy Complex	1,761
Barry	1,658
Bay Front	75
Bay Shore	621
Belews Creek	2,240
Belle River	1,260
Big Bend (FL)	1,712
Big Brown	1,130
Big Cajun 2	1,730
Big Sandy	1,060
Big Stone	456

Table continued on next page.

Unit Name	Summer Capacity MW
Biron Mill	62
Black Dog	284
Black River Power	53
Blount Street	194
Boardman (OR)	557
Bonanza	460
Bowater Newsprint Calhoun Operations	66
Bowen	3,262
Brandon Shores	1,286
Brayton PT	1,531
Bremo Bluff	227
Bridgeport Harbor (PSEG)	524
Bruce Mansfield	2,360
Buck (NC)	369
Bull Run (TN)	868
Burlington (IA)	212
C P Crane	385
Canadys Steam	396
Cane Run	563
Canton North Carolina	53
Cape Fear	316
Capitol Heat & Power	2
Cardinal	1,800
Carneys Point Generating Plant	237
Cayuga	990
Cedar Bay Generating Co LP	250
Cedar Rapids	260
Chalk Point	1,907
Charles R Lowman	551
Cherokee (CO)	717
Chesapeake	595
Chesterfield	1,229
Cheswick Power Plant	562
Cholla	995
Clay Boswell	964
Cliffside	760
Clifty Creek	1,247
Clinch River	690
Clinton (IA ADM)	31

Table continued on next page.

Unit Name	Summer Capacity MW
Clover	882
Coal Creek	1,089
Cogeneration South	90
Cogentrix of Richmond Inc	190
Colbert	1,173
Coleto Creek	632
Colstrip	2,094
Columbia (WI)	1,074
Columbus Street	64
Colver Power Project	110
Comanche (CO)	660
Conemaugh	1,700
Conesville	1,925
Cope	422
Cornell Univ Central Heating	8
Coronado	785
Council Bluffs	806
Coyote	427
Craig (CO)	1,264
Crawford (IL)	532
Crist	996
Cromby Generating Station	345
Cross	1,160
Crystal River	2,302
Cumberland (TN)	2,462
D E Karn	1,791
Dallman	372
Dan River (NC)	276
Danskammer Generating Station	500
Dave Johnston	762
Decatur (IL ADM)	335
Deepwater (NJ)	220
Deerhaven	313
Dolet Hills	650
Duck Creek	366
Dunkirk Generating Station	607
E C Gaston	1,890
E D Edwards	740
E W Brown	711

Table continued on next page.

Unit Name	Summer Capacity MW
East Bend	600
Eastlake	1,222
Eckert Station	357
Eddystone Generating Station	1,341
Edge Moor	704
Edgewater (WI)	836
Edwardsport	160
Eielson Air Force Base Central	20
Elmer Smith	413
Elrama Power Plant	474
Endicott Generating	50
F B Culley	406
Fayette Power PRJ	1,605
Fisk Street	326
Flint Creek (AR)	480
Fort Martin	1,107
Four Corners	2,040
Frank E Ratts	244
G F Weaton Power Station	112
G G Allen	1,140
Gallatin (TN)	976
Gavin	2,600
General Chemical	30
Genoa No3	352
George Neal 1 4	950
Gerald Gentleman	1,365
Ghent	1,968
Gibbons Creek	462
Gibson Station	3,131
Glen Lyn	325
Gorgas 2 & 3	1,288
Grant Town	80
Grda 1 & 2	1,010
Green Bay West Mill	101
Green River (KY)	232
Greene County (AL)	517
H B Robinson	174
H T Pritchard/Eagle Valley	338
Hammond	846

Table continued on next page.

Unit Name	Summer Capacity MW
Harding Street	704
Harllee Branch	1,607
Harrington	1,066
Harrison (WV)	1,920
Hatfields Ferry Power Station	1,369
Havana	683
Hawthorne (MO)	565
Hayden	446
Healy	25
Hennepin Power Station	289
Herbert A Wagner	1,000
High Bridge	269
Holcomb Unit No 1	331
Homer City Station	1,884
Hoot Lake	156
Hudson Generating Station	991
Hugh L Spurlock	850
Hugo (OK)	450
Hunter	1,315
Huntington (UT)	895
Huntley Generating	712
Iatan	670
Independence (AR)	1,651
Indiantown Cogeneration Facili	330
Intermountain	1,778
Irvington	423
J C Weadock	310
J H Campbell	1,435
J K Spruce	555
J M Stuart	2,340
J R Whiting	326
J Sherman Cooper	341
J T Deely	830
Jack McDonough	517
Jack Watson	1,041
James H Miller Jr	2,686
James River Power St	236
Jefferies	398
Jeffrey Energy Center	2,226

Table continued on next page.

Unit Name	Summer Capacity MW
Jim Bridger	2,120
John E Amos	2,900
John P Madgett	374
John Sevier	704
Johnsonville (TN)	1,206
Joliet 29	1,036
Joppa Steam	1,014
Juniata Locomotive Shop	4
Kammer	600
Kanawha River	390
Keystone (PA)	1,700
Killen Station	600
Kincaid Generation LLC	1,168
King	571
Kingston	1,434
Kodak Park Site	200
Kraft	317
Kyger Creek	1,025
L V Sutton	613
La Cygne	1,362
Labadie	2,300
Lake Road (MO)	152
Lake Shore	230
Lansing	316
Lansing Smith	351
Laramie River 1 3	1,668
Lawrence Ec	572
Lee	407
Leland Olds 1 & 2	669
Limestone	1,602
Lon Wright	120
Louisa	700
Lovett	432
Luke Mill	60
M L Hibbard	41
M L Kapp	236
Marshall (MO)	26
Marshall (NC DUKE)	2,090
Martin Drake	259

Table continued on next page.

Unit Name	Summer Capacity MW
Martin Lake	2,250
Marysville	200
Mayo	745
McIntosh (GA SAVNAH)	155
McMeekin	250
Mead Paper Division	78
Meramec	876
Mercer Generating Station	648
Merom	1,000
Merrimack	433
Miami Fort	1,243
Michigan City	589
Mill Creek (KY)	1,470
Milton R Young	705
Mirant Birchwood Power Facilit	237
Mitchell (GA)	153
Mitchell (WV)	1,600
Mitchell Power Station	359
Mohave (NV)	1,580
Monroe (MI)	3,020
Monticello (TX)	1,880
Montour	1,543
Montrose	510
Mountaineer	1,300
MT Poso Cogeneration	52
Mt. Storm	1,587
Muscatine	280
Muskegon	37
Muskingum River	1,365
Muskogee	1,666
Natrium Plant	123
Naughton	700
Navajo	2,250
Neal South	644
Nearman Creek	235
Nebraska City	632
Nelson Dewey	218
New Castle Plant	413
New Madrid	1,160

Table continued on next page.

Unit Name	Summer Capacity MW
Newton (IL)	1,110
Niles (OH ORION)	216
North Branch (WV)	74
North Omaha	663
North Valmy	522
Northeastern	1,380
Northeastern Power Cogeneration Facility	50
Nucla	100
O H Hutchings	365
Ottumwa (IA IPL)	720
P H Glatfelter Co	50
Paradise	2,159
Pawnee	505
Petersburg (IN)	1,664
Phil Sporn	1,020
Picway	90
Pirkey	580
Plains Escalante	247
Plant 3 McIntosh	531
Pleasant Prairie	1,224
Pleasants	1,065
Polk Station	255
Port of Stockton District Ener	44
Port Washington	160
Portland (PA)	401
Potomac River	482
Powerton	1,538
PPL Brunner Island	1,434
Prairie Creek 1 4	197
Presque Isle	618
Pulliam	396
Purdue University	38
Quindaro	208
R D Morrow	400
R E Burger	406
R Gallagher	560
Rawhide	270
Ray D Nixon	208
Red Hills Generating Facility	440

Table continued on next page.

Unit Name	Summer Capacity MW
Reid Gardner	556
Richard H Gorsuch	212
River Rouge	735
Riverbend (NC)	454
Riverside (MN)	382
Rochester 7	252
Rockport	2,600
Rodemacher	963
Rollin Schahfer	1,625
Roxboro	2,462
Roy S Nelson	1,399
Rush Island	1,166
Salem Harbor	742
San Juan	1,643
San Miguel	391
Sandow	390
Sandow No 4	554
Scherer	3,430
Seminole (FL)	1,316
Seward	520
Shawnee (KY)	1,330
Shawville	597
Sheldon (NE)	225
Sherburne County	2,292
Sibley (MO)	502
Sikeston	233
Sioux	950
SIPC Marion	272
Sixth Street (IA)	74
Sooner	1,019
South Oak Creek	1,135
Southampton	67
Southeast Missouri State Univ	6
Southwest	222
Springerville Generating Station	800
St Clair	1,662
St Johns River Power	1,252
Stanton Energy Center	886
State Line Energy	515

Table continued on next page.

Unit Name	Summer Capacity MW
Stockton Cogeneration Co	54
Sunbury Generation LLC	361
T B Simon Power Plant	55
Taconite Harbor Energy Center	225
Tanners Creek	980
Tecumseh Ec	243
Tenn Eastman Division A Division of East	194
Tes Filer City Station	65
Thomas Hill	1,120
Tolk	1,080
TransAlta Centralia Generation	1,405
Trenton Channel	730
Trimble Station (LGE)	512
Txi Riverside Cement	22
Unc Chapel Hill Cogeneration	24
University of Alaska Fairbanks	9
University of Iowa Main	21
University of Missouri Columbia	51
University of Northern Iowa	8
University of Notre Dame	21
Urquhart	94
Utility Plants Section	18
Uw Madison Charter St Plant	6
Valley (WI)	267
Valmont	186
Vanderbilt University	11
Victor J Daniel Jr	1,050
W A Parish	3,673
W H Sammis	2,220
W H Weatherspoon	176
W H Zimmer	1,300
W N Clark	43
W S Lee	370
Wabash River	668
Walter C Beckjord	1,118
Wansley (GPC)	1,783
Warrick	678
Wateree	700
Watts Bar Fossil	0

Table continued on next page.

Unit Name	Summer Capacity MW
Waukegan	789
Waupun Correctional Inst CTR	1
Welsh Station	1,584
Weston	490
White Bluff	1,620
Widows Creek	1,610
Will County	761
William C Dale	198
Williams (SC SCGC)	615
Willow Island	235
Winyah	1,155
Wood River (IL)	588
Wyandotte (MI)	72
Wyodak	335
Yates	1,295

SOURCE: Global Energy.

Table C-8
Chained Consumer Price Index for Energy

Series ID: SUUR0000SA0E						
Not Seasonally Adjusted						
Area: U.S. city average						
Item: Energy						
Base Period: December 1999=100						
Year	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**
Jan		100.2	116.8	98.6	112.4	121.2(U)
Feb		103.7	116.4	97.8	118.9	123.9(U)
Mar		108.9	114.4	101.9	125.4	125.8(U)
Apr		107.8	117.5	107.9	121.5	128.1(U)
May		108	123.7	108.5	118.1	134.7(U)
Jun		115.3	124.7	110.4	120.6	140.2(U)
Jul		115.4	117.4	110.9	120.9	137.6(U)
Aug		111.9	114.8	111.2	124.4	136.9(U)
Sep		115.9	117.9	111.4	128	136.0(U)
Oct		114	108.7	110.7	120.9	138.0(U)
Nov		113.4	102.6	110.3	117.4	138.5(U)
Dec	100	112.6	98.3	108.6	116.4	134.6(U)
Annual		110.6	114.4	107.4	120.4	133.0(U)

SOURCE: U. S. Department of Labor, Bureau of Labor Statistics.

Fraser Alert

October 2004
ELECTRICITY POLICY SERIES

THE FRASER INSTITUTE

Market solutions to public policy problems

Power Jolt Required:
Measuring the Impact of Electricity Deregulation

Introduction

Participants in electricity markets appear to be despondent. The public opinion fallout from the failed California market opening and corporate malfeasance at Enron has caused even industry insiders to believe that market-based policies may not work as expected.

For example, MacDonald (2003) writes that "Although the jury is out on deregulation—whether in

Main Conclusions

- **Electricity market deregulation, as measured by the RED Index, is related to greater supply and lower prices**
- **Alberta and thirteen US states are leading the way in North American deregulation. Ontario has turned the furthest away from deregulation reforms since 2000 and now ranks below California.**
- **Reforming jurisdictions have attracted more new generation than non-reformers, with 80 percent faster per capita growth in the US—and even more in Canada**
- **Deregulation has lowered after-inflation prices in the US, the UK and Australia. Prices in Alberta and New Zealand have risen for exceptional reasons.**
- **US states that have yet to reform could deregulate and drop prices there by 7 percent to almost 9 percent over five years. This is double the price drop that actually occurred in non-reforming states between 1997 and 2002.**
- **Moving Ontario and the rest of Canada to the Alberta level of deregulation would drop prices in Canada by an equivalent amount—and save residential customers alone over $1 billion**
- **Moving New South Wales and Queensland to the higher Victoria level of deregulation would drop prices there by 3 percent to 4 percent over five years and yield up to A$300 million in savings**
- **Consumers and taxpayers can reap these economic gains from deregulation by introducing customer choice, competition, privatization, market pricing and effective regulation**

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ACKNOWLEDGEMENTS
Myron Genyk provided exemplary research support for this *Alert*, courtesy of a generous contribution from the Donner Canadian Foundation.

purgatory or another unpleasant place where the song never ends—it is clear that in most jurisdictions the process has not delivered significant benefits to the residential consumer."

Trebilcock and Hrab (2004) also recently repeat a Borenstein and Bushnell (2000) quote that "short-run benefits [of deregulation] are likely to be small or non-existent, and the long-run benefits, while compelling and supported in theory, may be very difficult to document in practice."

These pessimistic notes are out of keeping with the significant deregulation benefits that have accrued over the past several decades in telecommunications, natural gas transmission, and air, rail, and truck transportation, not to mention the worldwide successes achieved through privatization and alternative service delivery.[1]

Is it true, as asserted by Thomas (2004) when writing from an international public service union perspective, that electricity as a commodity is fundamentally incompatible with market reforms? Or is it simply that the evidence is not yet widely disseminated on the economic benefits of freer electricity markets?

This *Alert* takes the latter view and sets out to measure the price and supply impacts of deregulation in the leading reform jurisdictions around the world.

American and Australian states and Canadian provinces are compared within country and the experiences of the United Kingdom and New Zealand are also highlighted. A regulatory measure is examined as one explanatory factor behind US state-level retail electricity prices. This *Alert* makes reform recommendations so that consumers and taxpayers can continue to reap economic gains from deregulation in the future.

Electricity Deregulation

The traditional electricity market model was structured as a state or private monopoly, with vertically integrated generation, transmission, and distribution of power. This entity was often price regulated by a public utility commission but, in many cases, was practically self-regulating.

The political nature of the structure, with politicians liable for industry issues to voters and an absence of market-based financial incentives, typically led to overinvestment in new capacity and high internal costs.[2] Subsequent stranded debt issues and upward pressure on prices were key reasons why policy makers examined the potential of deregulation to better serve customers and increase supply at a market-clearing price.

The deregulation process began in the United Kingdom in 1990 and has gone the farthest in the United States and Australia. The typical mix of policies separates the functions of generation, transmission, and distribution, introduces competition to generation and distribution, sets up an independent performance-based regulatory regime, and often privatizes state assets.

The Center for the Advancement of Energy Markets (CAEM) developed a very sophisticated measure of deregulation in the late 1990s, the Retail Energy Deregulation or RED Index.[3]

Table 1 shows the attributes of the index, which emphasize the importance of consumer choice, competition, privatization, market pricing and effective regulation. The index has existed since 1997 for the American states and has been calculated for Canadian provinces, several Australian states, the United Kingdom and New Zealand since then.[4]

Table 2 shows RED Index scores by jurisdiction. US states have been placed into three groups: those reforming the most, swing states that either had modest deregulation or backtracked on deregulation after 2000 (including California which is shown separately owing to its large size and notoriety), and non-reformers.[5] The Appendix tables show summary statistics for these jurisdictions, highlighting differences in size, standard of living, and type of electricity generation.

The strong reformers (13 US states, Alberta, the state of Victoria, the UK, and New Zealand) have high and rising deregulation scores in table 2.

The swing group (including Ontario) achieved impressive gains by 2000 but then backtracked owing to political pressure. It is notable here that Ontario swung the farthest away from the market of any jurisdiction (dropping from a peak RED Index score of 45 in 2002 to 10 in early 2003) and is now below California, widely seen as the pre-eminent government policy failure.[6]

The non-reform group have continuing negative scores, reflecting the fact that a number of them have deliberately closed off deregulation options.[7]

Supply Impact

Table 3 examines the extent to which jurisdictions with varying

Table 1: The Retail Energy Deregulation (RED) Index

Attribute	*Description*	*Weight*	*Question*
	COMPETITIVE FRAMEWORK CLUSTER (35%)		
1	Deregulation Plan	5%	Does a detailed restructuring plan exist?
2	Percent of Eligible Customers	5%	What percentage of customers is eligible for retail access?
3	Percent Switched	5%	What percentage of retail customers has switched to a non-utility supplier?
4	Competitive Safeguards for Generation	5%	What safeguards prevent affiliate favouritism by utilities?
5	Competitive Safeguards for Distribution	5%	What safeguards prevent affiliate favouritism by utilities?
6	Uniform Business Practices	5%	To what degree are business practices standardized?
7	Competitive Billing	3%	Is retail customer billing a competitive service?
8	Competitive Metering	2%	Is retail customer metering a competitive service?
	MARKET STRUCTURE CLUSTER (30%)		
9	Generation Market Structure	10%	What is the market structure for generation?
10	Wholesale Market Structure	10%	How centrally controlled is the wholesale market?
11	Retail Market Structure	10%	Are public plants providing retail services in the jurisdictions?
	STRANDED COST CLUSTER (3%)		
12	Stranded Cost Calculation	1%	Do stranded costs meet a market test?
13	Stranded Cost Implementation	2%	Are stranded cost charges fixed?
	CONSUMER CLUSTER (10%)		
14	Customer Information	2%	Are suppliers granted effective access to customer information?
15	Consumer Education	4%	Is a comprehensive customer education program required?
16	Default Provider	4%	How are default customers handled?
	DISTRIBUTION CLUSTER (20%)		
17	Default Provider Price Risk	4%	Do default prices allow effective competition from suppliers?
18	Default Provider Rates	4%	Are default rates properly set?
19	Performance-Based Regulation for Network Facilities	5%	Is performance-based pricing used for network facilities?
20	Network Pricing	2%	Are efficient pricing principles used for network pricing?
21	Interconnection to Grid	5%	Do policies allow small-scale generation?
	COMMISSION CLUSTER (2%)		
22	Commission Reengineering	1%	Has the commission reengineered its processes for a new regulatory regime?
23	Commission Budget	1%	Is the commission's budget commensurate with its new responsibilities?

Table 2: Retail Energy Deregulation (RED) Index Scores

		1997	*2000*	*2003*
Canada	Alberta	0	57	61
	Ontario	0	29	10
	Non-Reformers	-8	-7	-5
USA	Reformers	4	46	51
	Swing States	1	31	21
	California	9	38	11
	Non-Reformers	0	-1	-1
Australia	Victoria	N/A	N/A	50
	New South Wales	N/A	N/A	29
	Queensland	N/A	N/A	22
	Other States	N/A	N/A	N/A
UK		N/A	N/A	88
New Zealand		N/A	N/A	75

Note: Canadian data for 1998, 2001 and 2003
Source: Center for the Advancement of Energy Markets (CAEM)

Table 3: Annual Growth in Electricity Generation

		Generation ('97-'02)	*Generation /Pop ('97-'02)*	*Generation /GDP ('97-'01/02)*
Canada	Alberta	3.6%	1.7%	0.4%
	Ontario	1.0%	-0.5%	-3.3%
	Non-Reformers	0.3%	0.1%	-2.9%
USA	Reformers	2.1%	1.2%	-1.6%
	Swing States	2.7%	1.4%	-2.1%
	California	1.3%	-0.2%	-1.7%
	Non-Reformers	1.8%	0.7%	-1.9%
Australia	Victoria	3.4%	2.2%	-0.9%
	New South Wales	2.0%	0.7%	-1.6%
	Queensland	7.2%	5.1%	2.4%
	Other States	4.2%	3.2%	0.9%
UK		2.2%	1.9%	-0.2%
New Zealand		0.9%	0.0%	-1.6%

Source: See Appendix

deregulation progress have seen new generation supply, a pre-requisite for customer reliability and low and stable prices. Average annual growth rates in new generation for the latest available five years are shown, along with generation growth scaled to population and the size of the economy.

The main finding is that reformers have attracted much more new generation than non-reformers. This is clear in the Canadian and American examples, where the two groups can be directly compared. For example, US reformers saw 11 percent faster generation growth and 80 percent faster generation growth per capita than non-reformers. Alberta's growth in the Canadian context was even stronger.

Australian states generally had high generation supply growth, consistent with the fact that all of them have been deregulating (though not all of them have a RED Index score—see table 2). The UK has also had strong generation growth.

The New Zealand performance is less attractive. This may be partly due to the heavy reliance there on state-owned hydro generation (see Appendix table 2) and a regulatory backtrack in March 2004; thus, incentives and expectations for investment in generation have been tempered in New Zealand.

The second result from table 3 is that backing away from deregulation can have a significant effect on new supply. Such political interference introduces uncertainty to the market and raises risk premiums on investment. The effect can be seen especially in California and Ontario, where delays and politicized market openings affected investment intentions and lowered new supply growth.

Price Impact

A positive attribute of a successful deregulation is that electricity prices (including all subsidies) are lower than they would be under a continuation of the former state monopoly structure. This does not necessarily mean that prices are absolutely lower than before, as many jurisdictions hid price increases behind mounting debt loads and priced power below full costs. Prices may also have to rise in a deregulated market to attract new investment to restore the demand-supply balance and ensure that reliability conditions (continuous power when needed) are met.

The results in table 4 are rather heartening given these caveats. The table shows annual average retail price growth after inflation from 1997 to the latest available year for residential and non-residential customers. The fourth and sixth columns show how this growth compares to the prior five-year period, with negative numbers indicating that price growth was lower in the later deregulation period.

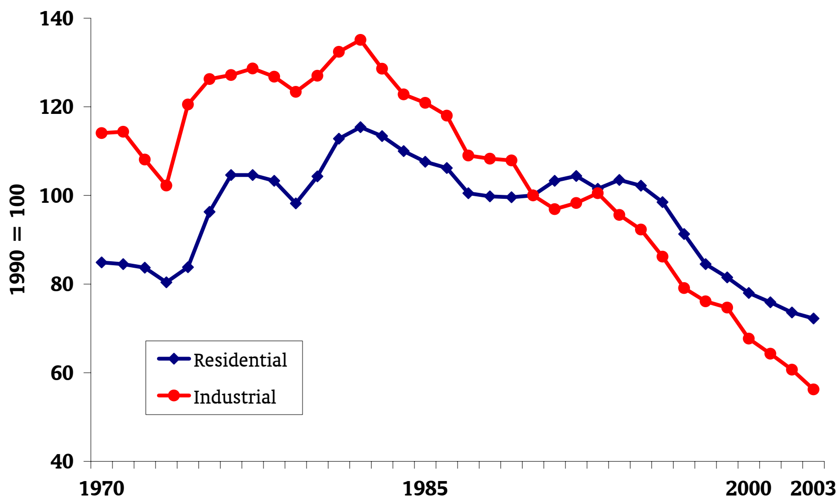
US reformers show significantly lower electricity price growth than non-reformers. Reformer jurisdiction prices are also absolutely

Table 4: Inflation-Adjusted Retail Electricity Prices

		Residential		*Non-Residential*	
		% Annual Growth 1997-2002/04	*Growth Difference 1992-97 to 1997-02/04*	*% Annual Growth 1997-2002/04*	*Growth Difference 1992-97 to 1997-02/04*
Canada	Alberta	1.5%	0.7%	N/A	N/A
	Ontario	0.8%	1.5%	N/A	N/A
	Non-Reformers	-1.1%	-1.0%	N/A	N/A
USA	Reformers	-2.8%	-1.1%	-1.8%	0.8%
	Swing States	-3.3%	-0.8%	-1.4%	1.7%
	California	-0.7%	0.5%	4.2%	7.0%
	Non-Reformers	-1.6%	0.8%	-1.1%	1.8%
Australia	Victoria	0.6%	-0.9%	-0.9%	3.4%
	New South Wales	-0.6%	1.3%	-1.4%	6.4%
	Queensland	0.3%	2.4%	-3.5%	-3.3%
	Other States	0.4%	0.7%	-0.1%	3.9%
UK		-3.5%	-0.8%	-6.5%	-2.1%
New Zealand		1.4%	-1.7%	0.0%	2.0%

Note: Canada for 2004, U.S. for 2002, Others for 2003. Non-residential prices for industrial users in UK.

Figure 1: U.K. Inflation-Adjusted Electricity Prices



lower than before deregulation in the US, in the UK, and for Australian non-residential customers. Residential customers in Alberta and New Zealand are exceptions to these general results, as are non-residential customers in California.

Table 4 shows that retail residential prices for US reformers dropped 80 percent faster than non-reformers and non-residential prices dropped 65 percent faster. US reformer prices also improved more from the five years prior to deregulation than did non-reformer prices. Figure 1 shows the longer and equally positive UK deregulation experience with declining inflation-adjusted electricity prices.

Alberta and New Zealand are the exceptional results that need further explanation.

According to Wellenius and Adamson (2003), the primary drivers of higher Alberta electricity prices were high natural gas fuel prices (more important there than elsewhere because of the absence of stable hydro or nuclear base generation), high import prices (partially influenced by the California situation) and low capacity reserves created by prior underinvestment. None of these factors were related to deregulation of the Alberta market.[8]

New Zealand residential prices have increased over time partly due to a reduction in cross-subsidies from commercial customers, according to MED (2004). This is a natural outcome of ensuring that customers pay the true cost of electricity. Some price relief came following an increase in supply in 1998 and 1999, but prices rose again after 2001 owing to supply shortages from a decline in natural gas availability and a drought that affected hydro generation.[9] As noted above, the New Zealand market has not seen large increases in generation since deregulating.

Statistical Results

The results discussed above are consistent with a generally positive impact of deregulation on increasing electricity supply and decreasing prices. A more formal statistical test can be done for the US states, where there are RED Index scores over a number of years and there is a spectrum of deregulation progress.

Tables 5 and 6 show the results of just such an exercise. A number of variables are used to explain the variation of residential and non-residential price growth from state-to-state between 1997 and 2002:

- The change in the RED Index score between 1997 and 2002,
- The extent to which the RED Index score backtracked after 2000,
- Electricity price growth between 1992 and 1997 (a trend effect),
- The electricity price level in 1997,
- The level of generation in 1997 (a market size effect),
- Growth in the economy (a demand effect)[10],
- Productivity growth (output per employee) in the utilities industry,
- Shares of energy sources in generation, and
- Energy fuel prices adjusted for inflation

The reduced set of estimated effects in the last two columns of the tables use only those factors that are most statistically significant, with the T-statistic as the measure of significance.

The most important result is that the extent of deregulation is related to electricity prices, even after taking all of these other factors into account. The estimated effect implies that prices after inflation decline between 0.2 percent to 0.3 percent per year over a five-year period for every 10-point increase in the RED Index score.

The implication of this result for non-reforming US states is especially profound.

Table 5: Explaining Inflation-Adjusted Residential Price Growth

	All Variables		*Reduced Set*	
Variable	*Estimate*	*T-Stat*	*Estimate*	*T-Stat*
RED Index * 10	-0.316%	-3.4	-0.275%	-3.4
RED Backtrack * 10	-0.005%	0.0		
Prior 5 Year Price Growth	0.825	3.8	0.700	4.6
Price Level in 1997	-0.005	-4.3	-0.004	-5.2
Generation in 1997	0.000	1.7		
GDP Growth	0.029	0.2		
Productivity Growth	-0.061	-1.0		
Share of Coal	0.004	0.3		
Share of Natural Gas	0.015	1.0		
Share of Nuclear	0.010	0.7		
Share of Hydro	0.020	1.4	0.023	2.4
Coal Fuel Price	0.065	0.8		
Natural Gas Fuel Price	0.040	2.0	0.044	2.6
Nuclear Fuel Price	0.077	1.0		
Constant Term	0.035	2.3	0.033	3.2
Adjusted R-squared	66%		68%	

Source: Author's calculations

Table 6: Explaining Inflation-Adjusted Non-Residential Price Growth

	All Variables		*Reduced Set*	
Variable	*Estimate*	*T-Stat*	*Estimate*	*T-Stat*
RED Index * 10	-0.293%	-2.1	-0.220%	-1.8
RED Backtrack * 10	0.588%	1.3		
Prior 5 Year Price Growth	0.322	1.2		
Price Level in 1997	-0.006	-2.2	-0.006	-3.8
Generation in 1997	0.000	0.9		
GDP Growth	0.037	0.2		
Productivity Growth	0.197	2.0	0.196	2.4
Share of Coal	-0.045	-2.2	-0.063	-6.2
Share of Natural Gas	0.011	0.5		
Share of Nuclear	-0.028	-1.2	-0.037	-2.6
Share of Hydro	0.019	0.8		
Coal Fuel Price	-0.056	-0.5		
Natural Gas Fuel Price	0.083	2.7	0.080	3.0
Nuclear Fuel Price	-0.005	0.0		
Constant Term	0.046	1.8	0.060	4.4
Adjusted R-squared	52%		55%	

Source: Author's calculations

Moving from the non-reformers' current RED Index score to the average reformers' score would reduce residential electricity prices by 1.4 percent to 1.6 percent a year after inflation, or between 7.3 percent and 8.5 percent over five years. For non-residential prices, non-reformers' prices would decline by 1.1 percent to 1.5 percent per year, or between 5.9 percent and 7.7 percent over five years.

All of these effects are double the price drop that actually occurred in non-reforming states between 1997 and 2002. These are the tangible costs of the current stall in deregulation in the US.

Translating the US results to Australia, New South Wales and Queensland would see a price drop of 2.9 percent to 3.7 percent over five years by moving to Victoria's higher level of deregulation. This would yield A$280 million to A$300 million in savings for residential and non-residential customers there.

If the results are applied to the Canadian context, a deregulation move in Ontario to Alberta levels would drop electricity prices by 5.8 percent to 8.3 percent over five years and in the other provinces by 7.5 percent to 10.8 percent. This is a saving across Canada of $950 million to $1.1 billion on residential electricity bills alone, based on current household expenditures.[11]

These gains are solely due to the impact of the deregulation process. Provincial governments outside Alberta are consciously foregoing this billion-dollar consumer benefit by not deregulating.[12]

Recommendations

The basic recommendation is straightforward: deregulate electricity markets.

More specifically, the way that any jurisdiction can reap the benefits of greater electricity supply and lower prices is to implement the reforms underpinning the RED Index:

- Create a competitive framework
  - Prepare a deregulation plan backed by legislation
  - Open the market to all customers
  - Full competition in generation and distribution
  - Competitive billing and metering
- Restructure the generation sector
  - Separate generation from transmission

- ○ Privatize generation assets
  - ○ Encourage bilateral contracting in wholesale markets
  - ○ Recover all stranded costs
- Restructure distribution
  - ○ No automatic default provider
  - ○ Performance-based price regulation
  - ○ Full cost network pricing
  - ○ Open access to the transmission grid
- Empower consumers
  - ○ Customer education programs
  - ○ Full choice to switch providers
  - ○ Open access to customer information
- Improve regulation
  - ○ Integrate retail gas and electricity regulation
  - ○ Reform regulatory organization and practices
  - ○ Provide sufficient funding for regulatory duties

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Appendix

Data were gathered from national and regional statistical agencies and industry associations for each country. Genyk (2004) provides sources and bibliographical detail.

Appendix tables 1 and 2 show shares of generation, size of population, income per capita and generation by fuel type for each jurisdiction or group. It is noteworthy that only a small segment of the national markets in Canada, the US and Australia have fully deregulated. There are also significant differences between jurisdictions regarding fuel types, from Australia's reliance on coal to the high share of marginal-pricing natural gas in Alberta, California and the UK. These are important differences to consider when assessing the impact of deregulation.

Table A1: Electricity Market Statistics

		Generation % of Country (2002)	*Population Million (2003)*	*Income Per capita (2001)*
Canada	Alberta	11%	3	$41,137
	Ontario	27%	12	$31,011
	Non-Reformers	62%	16	$25,995
USA	Reformers	33%	110	$38,188
	Swing States	14%	31	$34,138
	California	5%	35	$39,361
	Non-Reformers	48%	114	$32,227
Australia	Victoria	24%	5	$26,616
	New South Wales	30%	7	$27,375
	Queensland	23%	4	$22,690
	Other States	23%	5	$25,656
UK		100%	60	$26,345
New Zealand		100%	4	$20,249

Note: Income per capita in $US using OECD Purchasing Power Parities

Table A2: Generation by Fuel Type (2002)

	% of Total	*Coal*	*Natural Gas*	*Nuclear*	*Hydro*	*Other*
Canada	Alberta	66%	30%	0%	3%	1%
	Ontario	25%	8%	43%	23%	1%
	Non-Reformers	N/A	N/A	N/A	N/A	N/A
USA	Reformers	44%	25%	23%	3%	5%
	Swing States	52%	11%	25%	11%	2%
	California	1%	49%	19%	17%	15%
	Non-Reformers	59%	12%	17%	7%	5%
Australia	Victoria	97%	1%	0%	2%	0%
	New South Wales	98%	2%	0%	0%	0%
	Queensland	95%	4%	0%	1%	0%
	Other States	34%	30%	0%	36%	1%
UK		35%	34%	24%	0%	6%
New Zealand		4%	26%	0%	62%	7%

Note: Ontario data for 2003 - natural gas category includes oil

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Footnotes

1 See Crandall (2003) on deregulation gains, Megginson and Netter (2001) on privatization, and Domberger and Rimmer (1994) on alternative service delivery.

2 For a description of the Ontario experience, see Trebilcock and Hrab (2005).

3 See CAEM (2003). The Index has scores that can vary from –50 to +100 and is described there as "a reference tool that measures the progress states are making in moving from the monopoly model of public utility regulation to the competitive model."

4 Two other deregulation measures can be found in EIA (2003) and OXERA (2003). The former simply classifies American states according to whether their electricity industries are restructuring or not. The latter shows competitiveness rankings for eight countries and eight regions in 2001. However, the index screens out jurisdictions based on a minimum market size (excluding Alberta, for example) and a requirement for 100 percent market opening. The RED Index is superior because of its detailed structure and its time dimension. However, it does ignore a number of recently deregulating jurisdictions, notably Scandinavia, Germany, Austria, Spain, Singapore and several South America countries, that are therefore not considered in this *Alert*.

5 The states (in descending order of RED Index score) by group are: Reformers—Texas, Pennsylvania, Maine, New York, Washington D.C., Maryland, Michigan, New Jersey, Massachusetts, Virginia, New Hampshire, Ohio, Connecticut; Swing States—Arizona, Delaware, Illinois, Rhode Island, Montana, Oregon, West Virginia, California, Nevada, Arkansas; and Non-Reformers—all other states.

6 John Grant at the University of Toronto, in a review of this *Alert*, notes that "Ontario has evolved, and is still evolving, quite a complex governance structure that combines private entrepreneurship/competition-driven price signals/effective consumer response with overarching governmental direction of the generation mix and regulatory responsibility for adequacy and reliability." Though this suggests how the form of deregulation can vary by jurisdiction, it is still the case that the Ontario RED Index score of a year ago is unlikely to rise much, if at all, under current provincial government policies.

7 Of the Canadian provinces in this group, New Brunswick has partially opened its market as of October 1, 2004 by allowing 42 large electricity customers to enter into long-term bilateral contracts. The province now allows the sale or lease of some generation assets and has reorganized NB Power, the public monopoly, as a holding company. These modest reforms could raise its RED Index score from –8 to –4 or slightly higher.

8 Alberta also has no public sector electricity debt, the existence of which in most other provinces is a subsidy from taxpayers to ratepayers. If this debt was paid down by ratepayers over 25 years, it would add more than 30 percent to the average household electricity bill in Canada (outside Alberta). Thus, prices outside Alberta have been kept artificially low owing to rising public debt. Data source: *http://www.energy.gov.ab.ca/com/Room/Public+Reference/Commodity-Info/Facts+On+Electricity.htm*

9 See IEA (2003) on this latter point and Appendix table 2 that shows New Zealand's dependence on hydro generation.

10 Individual industry growth rates were also examined but discarded as explanatory factors after only non-durable manufacturing showed a significant (positive) impact on electricity prices. Upon further examination, this was wholly due to the apparel, paper, and printing industries, which together account for only 1.6 percent of the US economy and a small share of electricity demand.

11 The average impact splits as $350 million to Ontario and $675 million to non-reforming provinces. The numbers are calculated based on estimates of the number of households in 2004 (derived from the Census) and average household electricity expenditure in 2004 (derived from the Survey of Household Spending and the Consumer Price Index).

12 There are other monetary benefits from deregulation, notably from lower non-residential prices, sales of state assets and the termination of state-funded debt. These gains would collectively be greater than the estimated residential price decline effect.