UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Conference on Competition In Wholesale Energy Markets	**Docket No. AD07-7-000**

Joint Statement of John W. Rowe, Chairman and Chief Executive Officer
and
Elizabeth Anne Moler, Executive Vice President Government and Environmental Affairs & Public Policy
Exelon Corporation

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Mr. Chairman and Commissioners:

It is a pleasure for us to have the opportunity to talk to you today about the vitally important topic of competition in wholesale energy markets. The policies you adopt will have far reaching effects on how well we meet the challenge of providing for the nation's growing electricity demand.

Just eleven days ago, the Commission issued Order No. 890, a 1,255-page document addressing the need for reform of the Commission's landmark open access rules issued 10 years ago. Order No. 890 holds that the open access transmission rules are working, but need to be improved upon. We agree with this assessment and our remarks reinforce this basic framework.

In the course of our joint testimony today we hope to offer the Commission the benefit of our collective experience and to suggest additional steps the Commission should take (and not take) to enhance the operation of competitive wholesale markets.

Above all, we will reaffirm our conviction that our nation's need for reliable, reasonably priced energy is best realized through the competitive markets model. We will argue that the competitive model has served the country well during its relatively short history; is working well today; and is well-poised to serve our future energy policy objectives. Broadly stated, competition is clearly the right choice for developing new sources of generating capacity and for meeting the environmental challenges the world faces.

It is, therefore, more important than ever that we sustain and improve competitive markets and not be lured to repeat the mistakes of the past. We should not undermine competition through "reforms" that will discourage new investments and lead inexorably back to reliance on central planning for generation funded by utility customers. Rather, we should remain focused on building upon the successes of the competitive model so that it can help us meet what is everyone's ultimate objective: reliable electricity service, efficiently and fairly managed, at the lowest reasonable cost and risk to consumers.

In recent years this Commission has considered requiring a nationwide "Standard Market Design" (SMD) and retreated from that initiative. We do not expect you to reopen the SMD debate and impose SMD requirements nationwide. But, we implore the Commission to respect the policy choices made by regions that have embraced Regional Transmission Organizations (RTOs) and organized markets and seek ways to improve upon them rather than abandon them.

Our focus today is primarily on organized markets, which are currently in place in New England, New York, PJM, MISO, and Texas/ERCOT. As you are well aware, California's market reforms have been approved and an organized market will be put in place next year. When boiled to its essence, our advice is really quite simple: take steps to improve these markets but leave the essential elements of the organized market model intact.

The remainder of our joint testimony today addresses three topics.

1) We summarize the challenges the industry faces and the key "lessons learned" from our experience under three different regulatory models – and discuss why the wholesale competition model works best.

  a. The Rate Base/Cost of Service Model
  b. The PURPA/IRP Model, and
  c. The Wholesale Competition Model.

2) We describe how organized markets are an essential prerequisite to this competitive model, and discuss the key features of organized markets which must be preserved.

3) We offer specific proposals for improving organized markets ("the Do's") and discuss what proposals by others the Commission should *not* adopt that would undermine competition ("the Don'ts").

In the course of preparing this testimony we have reviewed literally hundreds of pages of documents from opponents of competition and organized markets. There are a number of "myths" about them that we fear are becoming urban legends that need to be debunked. We have prepared a brief document – Competition Myths and Facts – to set the record straight. It is attached to our joint testimony.

Lessons Learned: Competition Works Best

A Look to the Future

As a nation, and as an industry, we face an unprecedented challenge. The Energy Information Administration (EIA) estimates that we will need to invest over $400 billion in new generation by 2030, $18 billion in transmission over the next 3 years, and $140 billion in new distribution facilities over the next 10 years if we are to ensure both our future energy security and address global climate change.[1] The question we must confront is whether wholesale competition, particularly competition in organized markets, will better enable us to meet that challenge. Quite simply, is competition part of the problem, or part of the solution?

Competition – Not the Cause of Rising Prices

The recent run-up in wholesale electricity prices has rekindled debate about the wisdom of federal and state policies promoting competitive wholesale electricity markets. It is clearly appropriate to review why prices are increasing and understandable why such increases would cause concern in public policy forums. But the premise forwarded by some that competition and organized markets are causing wholesale price increases is simply wrong. And what's worse, such misconceptions divert attention from the real challenges facing us.

The notion that competition or organized markets have caused recent electricity price increases is refuted by the facts: since 1999, electricity prices have increased about 34% both in states with and without organized markets. And this is less than prices for other fuels have increased. (*See* Appendices A and B.) This shouldn't be a surprise. The recent run up in electricity prices is not due to competition or organized markets; it is due to increased fuel prices, particularly natural gas. Price increases in states with and without organized markets have tracked each other. (*See* Appendix C.) Neither competition nor cost based regulation can protect consumers against fuel price increases originating in global energy markets. Nor will competition or cost-based regulation protect consumers against price increases for steel, copper, and other commodities needed

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[1] Energy Information Administration, *Annual Energy Outlook* 41 (2007).

for "iron in the ground" in coming years. But in our view, competition does offer the *best* mechanism for responding to all of these price increases, in both the near and the long-term.

Some argue that competition isn't working when low cost nuclear and coal units get paid a price based on gas-fired generation – they believe customers are entitled to pay prices based on embedded costs. Of course, you hear this argument only when embedded costs are lower than market prices. When embedded costs are high, the refrain is that the shareholder must bear the cost. Ironically, public refusal to pay what once was the high cost of these units led to their becoming market-based in the first place. If we are to have any hope of attracting new investment and new technologies on the scale needed to address our future needs, we must avoid another round of "heads we win, tails you lose" regulation. Competition, and specifically the single clearing price auction, offers the best hope of attracting the investment and innovation needed to ensure our future energy security and address global climate change, without burdening consumers with the cost of someone else's plans.

Some argue that we must return to the "good old days" of rate base regulation, integrated resource planning (IRP), or at least long-term contracts to ensure that we have "the right" resources for the future at reasonable costs. Yet the history of the last 30 years, fairly remembered, makes plain that these central planning efforts using the customers' money – whether done by utility executives, regulators, or even legislators – have not produced economic results. The problem, of course, is that future electricity prices are inherently and irreducibly uncertain. Despite best efforts, predicting future load levels and fuel prices, much less changes in technology and environment restrictions, is perilous. Central planning using the customers' money has not been particularly successful in dealing with these uncertainties. When the assumptions used to determine "the right" resources have proven to be wrong, customers have borne the cost. In contrast, our more recent experience with competitive markets demonstrates that competition improves operating performance and existing infrastructure utilization, as well as attracting investment capital while shielding customers from investment risk. Merchant generators have constructed 167 GW of new capacity since 1999. As we discuss below, adjustments and refinements of current market mechanisms will better ensure new merchant generation. But we believe the facts show that organized markets are the best means to meet resource needs.

The Way Forward

The EIA estimate of future investment requirements suggests that the challenge we face in addressing our future energy security and addressing climate change is enormous, both in scope and estimated expense. Rate

base regulation, IRP or even long-term contracts will not assure the needed investment, and certainly will not assure that what is built will be at the lowest possible cost. The answer is not new construction at any cost and regardless of the risk that would be borne by customers. The answer must be new construction, and new technology, at the lowest possible cost, and with the lowest possible risk to consumers. We believe that competition can best deliver that answer.

In the pages that follow, we offer recommendations on further market refinements. Our focus is on improving the operation of the Nation's competitive, organized markets, which cover regions where two-thirds of Americans live. For these markets, we are convinced that enhancing the development of wholesale competition is critically important if we as a nation are to successfully address our future energy security and global climate issues.

Three Regulatory Models – Third Time's a Charm

Before we address our recommendations, however, at the Chairman's request, we include a description of the three basic regulatory models we have experienced, and the lessons we have learned from them.

1. The Rate Base/Cost of Service Model

Rate base or cost of service regulation at the state level was the industry standard until the mid-1980's. The rate base model rests on the premise that the monopoly utility, with appropriate regulatory oversight, could plan to serve its customers' needs in an economic fashion, choosing how much of which resources to build or buy, and recovering only its prudently incurred costs and a reasonable return. It worked reasonably well during a period of predictable load growth and declining generation costs.

But when energy prices surged in the late 1970s, accompanied by high inflation and stagnant economic growth, rate base regulation came under attack across much of the country. Retail electric rates increased dramatically as good faith assumptions made by utilities (and the federal government) in support of the nuclear construction effort proved wildly inaccurate. We all remember that nuclear construction costs increased substantially in the wake of Three Mile Island, but we tend to forget the other factors that made these investments turn out to be so uneconomic. Load growth was far lower than projected. Inflation was much higher. Oil prices actually fell, rather than continuing to rise steeply as forecast. And natural gas, rather than being scarce as well as illegal to use in the production of electricity, turned out to be both plentiful and cheap. And, to add insult to forecasting injury, there was also substantial technological progress – but in natural gas generation technology, not nuclear or coal.

As a consequence, the "regulatory bargain" implicit in rate base regulation was "remade" in the breach – state regulators across the country disallowed nuclear costs as imprudent or uneconomic. (*See* Appendix D.) Utilities across the Northeast and Mid-Atlantic States saw their balance sheets deteriorate, and credit ratings plunge. Public Service Company of New Hampshire was forced into bankruptcy, and several other utilities went to the brink. And many policymakers began to question whether the generation of electricity was in fact a natural monopoly.

<u>2. The PURPA/IRP Model</u>

Congress tested that proposition when it enacted the Public Utility Regulatory Policies Act of 1978 (PURPA). PURPA required utilities to buy energy from "qualifying facilities" at a cost not to exceed their "avoided (marginal) cost." PURPA was intended to diversify fuel supplies, to promote efficient production using indigenous fuels, and to open the door to independent generators.[2]

State regulators in many parts of the country followed suit by adopting what came to be known as Integrated Resource Planning (IRP). The PURPA/IRP model attempted to avoid the perceived problem – construction cost overruns under rate base regulation – by forecasting a utility's "avoided costs" over a 20+ year period. They projected how much new generation would be required, and then required utilities to sign long-term contracts for the required supply. In so doing, they believed that construction cost and operating risk would be shifted from customers to suppliers.

Good results under this model proved equally elusive. It turned out that load growth, fuel price and technology costs were no easier for intervenors and regulators to forecast than they had been for utilities back in the rate base era. The forecasted avoided costs, driven by inflated oil price projections, never materialized – and the long-term contracts soon became above-market obligations foisted on captive customers much like nuclear costs had been during the rate base era. The pattern was repeated in many places including Massachusetts, Maine, New York, Connecticut, Pennsylvania, and California.

Ultimately, retail rate increases associated with these expensive long-term power contracts – just as much as nuclear cost overruns from the rate base era – prompted the push for restructuring and competition. In fact, when the transition to retail competition took place, for many utilities the

2 John Gulliver and Donald N. Zillman, *Contemporary United States Energy Regulation* (Oxford University Press 2006).

stranded costs associated with the purchase power contracts were greater than the stranded costs associated with their own over-market generation. (*See* Appendix E.)

3. The Wholesale Competition Model

Congress took a further step toward opening up electricity markets and encouraging competition when it enacted the Energy Policy Act of 1992 (EPACT). EPACT granted FERC authority to require utility owned transmission lines to be opened to all generators, even those that competed with the transmission owner's own generation. FERC subsequently implemented EPACT in 1996 with Order No. 888, which set the stage for independent system operators and true interstate wholesale competition. And state policymakers in more than two dozen states, including California and much of the Northeast, again followed suit by restructuring retail electricity markets.[3]

California Meltdown

Our early experience with wholesale and retail competition was mixed. In the initial aftermath of restructuring, price increases led merchant developers to construct new generation. When California experienced extremely hot weather in June of 2000, however, the state-developed market design turned out to allow parties to exploit the market rules – which some chose to do, causing dramatic price increases and repeated rolling blackouts. Two of California's three major utilities suffered severe financial distress, since they were precluded from passing through the price increases to customers. The State of California was ultimately obliged to purchase electricity on their behalf, and in the process provided a perfect case study in the danger of entering into long-term contracts when prices are high. While the situation has since stabilized, California and the subsequent failure of Enron have become potent symbols of the dangers of a poorly designed and poorly monitored marketplace.[4]

Recent Success

Fortunately, the continuing experience in other parts of the country has been much better. The success and stability of ISOs and RTOs in New England, New York and PJM have demonstrated not only that open access can succeed, but also that it can create deep, liquid wholesale markets. PJM today oversees one of the largest competitive wholesale markets in

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3 *See* Energy Information Administration, *Status of State Electric Utility Deregulation* (2003).

4 For a more detailed description of the California debacle and subsequent work out, *see* Gulliver and Zillman, *supra*, at n. 2.

the world. Now that ComEd, AEP and Dominion have joined, the PJM RTO extends from the Mississippi River to the Atlantic Ocean, across 13 states, plus DC, and serves a population of 51 million people with a peak load of nearly 145,000 MWhs.

That market has brought real benefits to consumers. Recent studies by PJM, CERA, GAO, LECG, Bates-White and Synapse have all confirmed that wholesale competition has improved the operating performance of existing generating units, reduced their cost of operation, resulted in the construction of significant new generation, and most importantly, significantly reduced wholesale prices from what they would have been, and ultimately retail prices. Looking at the increase in nuclear capacity factors and the INPO Index, which measures various performance factors for nuclear plants, again illustrates the benefits of RTOs with organized markets as compared to regions without RTOs. (*See* Appendix F.) In Pennsylvania alone, Bates-White puts the value to consumers of increased output from Pennsylvania nuclear plants at over $450 million annually in PJM East.[5] LECG estimates that competition has resulted in an annual rate reduction of between $430 million and $1.3 billion within PJM and NYISO from 1998 to 2004.[6] And CERA recently put the total savings to residential consumers as a result of competition at $34 billion between 1997 and 2004.[7]

<u>Success in Illinois</u>

Organized markets such as PJM also have greatly aided state restructuring programs, including most recently Illinois. Like many state restructuring laws, the 1997 Illinois Restructuring Act sought to reduce the risk to customers from future generation decisions and long-term contracts by fostering both wholesale and retail competition. It encouraged formerly integrated utilities to divest their generation, and required that they join ISOs to aid in the development of liquid, competitive markets. Six years ago, with this Commission's approval, Commonwealth Edison divested itself of its generation, transferring 9,550 MWs of nuclear to its affiliate ExGen, and selling its remaining 9,772 MWs of fossil generation to competitors. Three years ago, again with this Commission's approval, ComEd joined its affiliate PECO as a member of PJM. Today, ComEd owns

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5 Collin Cain and Jonathan Lesser, Bates White LLC, *The Pennsylvania Electricity Restructuring Act: Economic Benefits and Regional Comparisons* (2007).

6 Scott M. Harvey, Bruce M. McConihe, and Susan L. Pope, LECG, LLC, *Analysis of the Impact of Coorddinated Electricty Markets on Consumer Electricity Charges* (2006).

7 Cambridge Energy Research Assoc., *Beyond the Crossroads: The Future Direction of Power Industry Restructuring* (2005).

no generation, and must rely on the PJM market to procure its customers' needs.

Wholesale competition in Illinois means that ComEd has made no 20- or 30-year generation commitments for which its customers are at risk. In fact, until last month ComEd's retail rates had been frozen for 10 years after a 20% reduction at the time of restructuring.

Yet during that same period, substantial amounts of new generation have been added in Northern Illinois – over 9500 MW of new gas-fired generation,[8] and over 900 MW[9] of nuclear uprates. All of this capacity has been added on a merchant basis, without <u>any</u> risk to Illinois retail customers, by shareholders and investors in a wide variety of companies.[10] Moreover, the performance of the existing fleet has also dramatically improved. In 1997, the capacity factor for ComEd's nuclear units averaged 47% – today, those same machines are part of a much larger and safer fleet whose 2006 capacity factor averaged 93.9%. To the average consumer, this means that the effective output of the local generation fleet has almost doubled, without building a single reactor, and without jeopardizing safety.

The Illinois Restructuring Act also required ComEd to join an independent system operator. After lengthy regulatory proceedings, ComEd joined PJM on May 1, 2004. Since then, PJM's and MISO's organized markets have proven critical in charting a new competitive future for Illinois.

ComEd's restructuring included a 20% rate reduction followed by an eight-year retail price freeze. That freeze was extended by the Legislature for a total of 10 years. The freeze expired on schedule December 31, 2006. During the freeze period ExGen had a full-requirements contract to serve ComEd's POLR load.

In anticipation of the expiration of the full-requirements contract, the Illinois Commerce Commission (ICC) explored various options for

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[8] After this new, efficient gas fired capacity was added, less efficient gas-fired units were retired. An older gas-fired thermal station with a heat rate on the order of 11-12,000 BTU/kWh was retired whereas the new gas-fired combined cycle units connected to the ComEd system have heat rates on the order of 8,000 Btu/kWh. The efficiency increases between the 1960's vintage gas-fired peakers and the peakers installed during this period are even greater.

[9] 900 MW is enough power to serve more than 1 million average residential customers. This added capacity annually avoids more than 9 million tons of carbon dioxide emissions to the atmosphere compared to adding the same amount of coal-fired generation.

[10] At least ten different companies own generation in ComEd's zone: Midwest Generation, NRG, LS Power, Constellation, PPL, Ameren, Calpine, Duke, Tenaska, and Dominion, in addition to a variety of wind resource owners.

suppliers to serve ComEd's load. An extensive stakeholder process, under ICC oversight, resulted in the development of the Illinois Auction Process, a declining price auction where generators bid to serve "slices" of ComEd's load. The Illinois Auction Process is described in detail in Commissioner Erin O'Connell-Diaz's testimony in this proceeding.

As a result, when the Illinois Auction Manager went to the wholesale market last September to procure ComEd's POLR supply for the next three years using a full requirements auction (a procurement method that would not have been possible without the organized RTO markets in PJM and MISO) the resulting prices for residential customers are actually 3% <u>lower</u> than the pre-freeze levels of 10 years ago. Fourteen suppliers are now providing for a load once served by a single monopoly utility. And they are doing it more economically and more efficiently.

The Commission is undoubtedly aware some have declared competitive restructuring to be a failure because "true" retail competition has not developed – meaning that there are few suppliers competing to serve retail customers. But that is simply wrong. First, in choice states there absolutely *is* competition at the retail level for industrial and large commercial customers. For instance, in Illinois over 80% of the large commercial and industrial load is now being served by a competitive retail supplier. And second, competition for residential customers has been stymied by retail price freezes that were a byproduct of restructuring in many states. As those price freezes expire, we would expect more retail suppliers to emerge. And meanwhile, states are well positioned to harness the benefits of wholesale competition through POLR auctions such as the Illinois Auction. In Illinois, residential and small commercial customers are now reaping the benefits of wholesale competition and organized markets, even without a competitive retailer supplying their loads.

So to recap – since restructuring occurred in Illinois over 10 years ago, suppliers have added over 10,000 MW of new capacity to the market without imposing long-term risks on customers, nuclear performance has improved markedly to the benefit of both shareholders and customers, large retail customers are choosing alternative suppliers in increasing numbers, and residential retail prices based on the recent auction results are still lower than cost-based prices over 10 years ago. Although some fail to recognize it, Illinois restructuring efforts have been an enormous success, and would not have been possible but for the success of PJM, and the overall success of FERC-jurisdictional organized markets.[11]

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[11] Commercial and industrial consumer access to supplier choice was phased in with all businesses having choice by January 1, 2001. Currently 12 suppliers serve over 40,000 GWh of load. Seven retail energy suppliers (RES) have been approved by the Illinois Commerce Commission and are currently seeking ComEd registration. Over 60% of

Essential Role of Organized Markets

What is true in Illinois is true throughout the restructured regions – the underlying organized markets are absolutely essential to the success of the competitive model. In addition, organized markets are essential to retail choice programs in many jurisdictions. For example, without organized markets, the benefits of improved dispatch and grid utilization could not be realized. Without organized markets, neither the price signals nor the market liquidity necessary to attract new generation investment on a competitive basis would exist. And without organized markets, the full requirements supply auctions used so successfully in New Jersey, Illinois and Maryland would not be possible.

The term "organized markets" may mean different things to different people, so it is important to this policy debate for us to be clear about what the term means to us. Not surprisingly, our definition of organized markets looks a lot like PJM. But the rules and procedures that describe PJM fill volumes, so that is not a particularly helpful description. From our perspective, there are four elements of organized markets that are essential to realizing the benefits described above.

Four Elements of Organized Markets

1) **A set of requirements to ensure reliability, and adherence to the NERC reliability standards, mandatory capacity requirements for load serving entities, and the obligation of all capacity resources to schedule or offer their full available output. Reliability is, of course paramount, and these requirements speak for themselves. But organized markets must include each of these provisions.**

2) **Transparent and liquid markets for electricity, resulting from a bid-based security constrained economic commitment and dispatch in which all "similarly situated" generators bid and receive market prices for electricity (a.k.a., Locational Marginal Price, LMP, or single clearing price markets).**

3) **Central markets administered by an independent entity, including a market monitor with authority to mitigate prices if a particular segment of the market is not workably competitive.**

4) **Reliance on market-based investments in new generation resources, not ratepayer-funded, long-term commitments planned by policymakers, regulators or utilities. The role of organized markets is to establish reliability requirements, to provide price transparency, and leave the investment decisions to market participants.**

ComEd's commercial and industrial load is served by alternative suppliers and over 80% of the large customer load are served by alternative suppliers.

We believe the market rules and structure of PJM and the other RTOs (except SPP) currently provide all of these essential elements. That is not to say that there is no room for improvement – there is. And in the next section we lay out several specific suggestions for improving organized markets, and making them even more successful. Any suggestion that would weaken or eliminate any of these four essential elements would not be an improvement – it would be a huge mistake.

Further, any suggestion that this Commission is reconsidering the basic underpinnings of the single clearing price market rules would cause a very significant capital flight. Generation developers simply will not make the necessary investments in new generating capacity we need if they face an uncertain regulatory environment. Any Commission action to revoke any of the essential elements of organized markets would undoubtedly result in years of litigation.

In this area, as in so many others, the maxim "first, do no harm" should guide the Commission. We offer these four essential elements as a yardstick to help ensure this goal is met.

Recommendations for Improving Organized Markets

We believe the PJM LMP market model represents the Nation's most advanced RTO model. We have supported development of the Texas nodal market, which is also based upon an LMP-style regime, as well as LMP-style markets in New England and MISO. After California's colossal market failure, with repercussions that are still being felt today, California's new Market Redesign and Technology Update implementation contains many features of the nodal or LMP model.

But we should not stand pat. We urge the Commission to adopt further enhancements to the PJM model that will facilitate market-based investment in new generation, better integrate demand side alternative, and require more efficient dispatch and operations.

The Chairman and the Commission staff have urged us to be specific when we suggest changes to the current model. It is important to note that many of those who criticize today's markets <u>simply whine; they don't have solutions</u>. Their studies complain about assumptions made in others' studies but don't provide concrete conclusions of their own.

When we at Exelon think about how to approach changes that might result from this series of technical conferences on wholesale competition; we divide them into "Do's" and Don'ts".

With apologies to a soft-drink company, we urge you to "Do the Do's" and to "Don't Do the Don'ts."

"DO'S" to Enhance Competition and Reliability in Markets

1. FACILITATE MARKET-BASED NEW GENERATION IN RTOS.

a. Make sure that prices in organized markets reflect the true value of the energy.

While it is important to avoid the exercise of market power in central energy markets (and RTOs have market monitors and sophisticated mitigation protocols in place to achieve this), it is also important not to artificially restrain or depress energy market prices (through the exercise of bid caps or mitigation), particularly during periods of "scarcity". When electricity is scarce (meaning we need every megawatt we have, or nearly so) nobody has market power and prices *should* rise to signal the need for additional resources. Any RTO pricing or mitigation regime that does not allow prices to rise in this situation will discourage the development of generation needed to solve the supply shortage. In addition, scarcity pricing will attract investment in demand response programs and products that optimize and enhance system efficiency.

There are numerous circumstances where it is improper to mitigate generator bids, or when current bid caps might be too low:

i. When transmission providers must curtail load – whether involuntarily or voluntarily, and whether load is paid for being curtailed or not;

ii. When generation is in such short supply that the transmission provider dips into the operating reserve to serve load;

iii. When an insufficiency of generation causes voltage reductions;

iv. When the transmission provider expects such a shortfall in generation that it appeals to the public to conserve power; or

v. When the RTO notifies generators that all available generation may be called upon.

In any of these circumstances, there is a scarcity of generation and energy prices should not be set as if all demand is being met. Rather, they should reflect the scarcity and should be permitted to rise or should be administratively set at a level that reflects the need for additional supply. Investors will be encouraged to build new generation and demand response providers will be motivated to maximize their participation.

In fact, after shortages on a few hot days during the summer of 2005 in Eastern PJM, PJM filed a tariff amendment to address scarcity

circumstances and FERC approved a settlement among the parties that suspends energy market mitigation when PJM initiates certain emergency type events. PJM's settlement does not go far enough, however. It fails to cover all the events that should trigger scarcity pricing and it is limited to real time situations, even though there have been and will continue to be circumstances when it is appropriate to suspend bid caps and mitigation on a day-ahead basis. RTO scarcity pricing provisions should respond to the full gamut of circumstances that signal energy is in short supply.

b. Implement long-term financial transmission rights.

Transmission congestion costs in organized markets can cause the price of transmission to vary, thereby creating uncertainty for transmission customers about the price of delivered electricity. This uncertainty impedes long-term contracts between wholesale buyers and sellers of electricity in competitive wholesale markets. Long-term financial transmission rights enable transmission customers – whether load serving entities (LSEs) or generators – to enter into long-term contracts at a fixed price and hedge the risk of congestion.

In organized markets, the independent transmission operator such as PJM dispatches generation units under bid-based, security-constrained, economic dispatch procedures. That is, generation generally is dispatched in the order of the lowest bid first until all demand is met, subject to the availability of transmission capacity. Sometimes the security of the transmission system requires backing down a cheaper generator on one side of a transmission constraint and running instead a more expensive generator on the opposite side to avoid violating reliability criteria. The increased cost of the power supply necessitated by the transmission constraint creates "congestion costs" that are added to the price for transmission service paid by transmission customers.

LSEs such as distribution utilities often enter into long-term contracts at set prices with suppliers of electricity to serve their load. But when the cost of the transmission service varies because of congestion costs, these LSEs cannot be certain what the cost of delivered power will be, even though they have a fixed price contract for delivered electric supplies. By the same token, new generators wishing to sell to customers cannot be certain what the price of transmission will be and therefore what their revenues will be. Without certainty of revenues, investors in new generation, such as wind, have a hard time finding financing.

Long-term financial transmission rights give transmission customers certainty about access to transmission at a price certain, regardless of how generation units are dispatched to meet reliability criteria. Exelon applauds the Commission's orders requiring RTOs to make such long-term

financial transmission rights available (Order Nos. 681 and 681-A). PJM filed a tariff to implement the Commission's rule and a number of parties, including Exelon, negotiated a proposed settlement of issues surrounding auctioning long-term transmission rights which is pending before a settlement judge. (Docket No. ER06-1218-001.) Exelon believes the Commission should continue to pursue implementation of long-term transmission rights within all RTOs.

c. Implement forward capacity markets, such as PJM's RPM.

Exelon urges the Commission promptly to implement forward capacity markets such as PJM's Reliability Pricing Model (RPM), which is presently pending in Docket No. ER05-1410. The forward procurement auction is essential to allowing time for new generators time to bid into the auction and then build new capacity.

Developers consider total cost versus total revenues when deciding what and when to bid. Forward procurement auctions give developers the information they need to make those decisions. The RPM three-year forward market compromise will support needed peaking units, which can come on line within that time frame. And Exelon believes the forward capacity auction model also will provide market information and capacity payments which, in combination with energy and ancillary services payments, will signal sufficient revenues to support building base load or flexible mid-merit generation.

Other benefits of forward procurement include better information about when costs of operating older units will make them uneconomic in the market and will send them into retirement. Forward procurement allows coordination of planning for generation, transmission and demand response. More rational transmission planning and expansion will increase confidence that all current and future loads in the RTO footprint will be served reliably. Forward procurement may encourage demand response because large users may allow backup and emergency generation to be used as a capacity offset.

2. DIRECT RTOS TO ENHANCE DEMAND RESPONSE PROGRAMS AND INTEGRATE THEM BETTER WITH ENERGY MARKETS AND SCARCITY PRICING.

There is widespread recognition of the need to increase the amount of demand response in electricity markets. Organized markets like PJM have done a reasonable job of establishing demand response programs, but they need to grow. PJM's demand response program has grown from 359 MW in 2002 to over 2,200 MW in 2005; a six-fold increase. Nearly half of PJM's demand response resources are in ComEd. PJM recognizes

demand side resources in its recently approved Reliability Pricing Model (RPM) capacity market. A recent FERC Staff survey of demand response programs shows that even though Reliability*First* Corporation, a NERC reliability region encompassing most of PJM, has more demand response participation than any other NERC reliability region – over 8,000 MW – this still amounts to only 4% of Reliability*First*'s summer peak. Exelon is confident that RTOs will increase this percentage significantly by better integrating demand response with energy markets and scarcity pricing.

The following are suggestions for achieving this objective. RTOs should remove barriers that keep qualified customers from participating in demand response programs. For example, RTOs should establish minimum prices (minimum strike price) and hours of participation for demand response programs so that participants will be better able to predict the value of participation and will not be required to bid load on a daily basis. RTOs also should allow the aggregation of customer accounts in order to meet the minimum requirements for an RTO demand response program. This would allow more commercial loads to participate in the program. RTOs should standardize enrollment requirements, including interface system requirements, to reduce upfront costs and ongoing costs related to system changes. An innovation RTOs should consider is the creation of a mechanism, such as a call option, that would allow retail customers to sell demand resources to wholesale entities. The RTO would act as intermediary by scheduling the energy (when the option is exercised) as a sale from the retail customer to the wholesale entity. In general, RTOs should be directed to provide education, training, and dedicated customer service to support and encourage customers to participate in demand response programs.

In August 2006, FERC Staff published a report entitled, "Assessment of Demand Response and Advanced Metering" in Docket AD06-2. The report included a number of regulatory barriers that impede customer participation in demand response. Exelon recommends that the Commission adopt the following priorities to facilitate demand response participation: institute tariff rates based on marginal costs of producing electricity for customers that can provide demand response to eliminate the disconnect between retail and wholesale costs; pay participating retail customers for demand response promptly rather than waiting for the wholesale settlement period to end; and provide greater transparency and access to data for 3rd party providers to determine likely candidates for demand response rates and programs.

3. ADOPT MEASURES TO RESOLVE "SEAMS" ISSUES.

a. Require common methodology for calculating ATC and TTC.

Exelon applauds the Commission's Order No. 890 recognition of the importance of standardizing and exchanging data for calculating how much transmission capacity is available, both for planning and for real time transactions. Exelon believes the Commission appropriately has required NERC and NAESB to develop the appropriate standardized methodologies for calculating available transfer capability and well as other improvements in standardization, coordination and data exchange. It is critically important for the Commission to ensure that the requirements of Order No. 890 are implemented promptly.

b. Direct RTOs to better address day-ahead coordination based on results of day-ahead transmission security analysis.

Through formal coordination, including the state-of-the-art Joint Operating Agreement between PJM and MISO, RTOs have made great strides in improved security analysis. We believe that by building on these efforts the RTOs can further improve operations. For example, action taken by RTOs for transmission loading issues identified in their day-ahead security analysis needs improvement. Past experience has shown that RTOs have taken no day-ahead action (*i.e.*, change in generation dispatch or transmission configuration) to address potential next-day transmission loading issues identified in their day-ahead security analysis. The appropriate actions need to be planned and implemented day-ahead, in order to prevent reliability issues from arising in real-time operations.

4. <u>DIRECT RTOS TO IDENTIFY "BEST PRACTICES" FOR CONSIDERATION/IMPLEMENTATION WITHIN 180 DAYS.</u>

As RTOs mature and regional differences are recognized, RTOs and their respective stakeholders should identify best practices within the various areas and standardize those practices.

a. RTOs should adopt more consistent, transparent, and predictable operator dispatch decisions.

Decisions by the RTOs about which generation units to commit have an enormous impact on overall energy prices. But there are no standard guidelines for operators and their objectives in making dispatch decisions are not transparent to market participants. RTOs should develop "best in class" unit commitment procedures and reliability analyses and should apply those across all RTOs.

b. Develop RTO rate structures that encourage cost control.

Critics of RTOs complain the administrative costs of these independent transmission providers are high. Exelon acknowledges RTO costs are significant. But, as discussed in this statement, we believe that the public benefits of the increased operational efficiencies of the electric system far outweigh the administrative costs of RTOs.

Exelon also believes it makes sense for RTOs to adopt rate structures that impose controls on costs and allow greater transparency. PJM has adopted a "stated rate" mechanism under which it periodically files with the Commission its budgeted costs of operations for the next several years. The Commission and PJM's members have an opportunity to examine those costs and to recommend to the Commission that individual items be approved or disallowed. Once the Commission approves PJM's stated rates, its costs can be passed through in PJM's rates that are paid by transmission customers. PJM's stated rate is flexible enough to include a formula for recovering the costs of its planned second control center.

Precedent for this kind of review of costs incurred by an association that provides services to jurisdictional utilities can also be found in the Gas Research Institute, which filed its budget for approval at FERC so its costs could be allocated through its pipeline members' rates. Exelon believes the Commission should require other RTOs to adopt similar cost controls and transparency to ensure the costs of RTOs are minimized and the benefits of RTOs to consumers are maximized, preferably through fixed rates.

c. Require Market Monitors to Develop Best Practices; Require Them to be Implemented.

The Commission and the Market Monitoring Units of the RTOs should continue to evaluate the best practices associated with ensuring the various Market Monitoring units are independent, objective and can comprehensively monitor all aspects of the market to prevent the exercise of market power. These best practices should be consistent across all RTOs and should include both internal structural and administrative practices as well as external market monitoring practices, such as allowing energy and capacity prices to signal resource scarcity.

"DON'TS" – To Enhance Competition and Reliability in Organized Markets

1. DON'T ABANDON RTOS – RTOS ARE WORKING AND HAVE BROUGHT MAJOR EFFICIENCIES AND RELIABILITY IMPROVEMENTS.

This testimony has already discussed the considerable benefits of RTOs and organized markets. They have brought major economic, reliability, and efficiency gains to the regions they serve. The following benefits also merit consideration.

a. Regional planning is a growing success story.

RTOs have brought the reality of regional planning to this Nation. This is the culmination of a long effort by this Commission, dating back to at least 1993, to coordinate and plan transmission on a regional basis.[12]

RTOs are able to look at solutions that go beyond the individual transmission owners or control areas or even two interconnected owners. RTOs can direct transmission expansion by one transmission owner to fix a reliability problem in serving load connected to other transmission owners. This helps provide regional transmission solutions rather than multiple uncoordinated individual solutions. An example of this is the almost $1 billion 500kV line to be built by Allegheny and Dominion from Washington County in West Pennsylvania to Loudon County, Virginia, known as the Loudon line. While the siting of the line has been controversial, there can be no doubt that this line is needed to avoid reliability violations for many load areas and is an example of the benefits

[12] For example, in a Policy Statement on RTGs, or Regional Transmission Groups, issued on July 30, 1993, this Commission stated that "[p]roperly functioning RTGs will serve the public interest . . . by providing coordinated regional planning of the transmission system to assure that system capabilities are adequate to meet system demands. . . RTGs may also significantly enhance regional transmission planning by providing a mechanism for cooperation among state commissions and the utilities they regulate." 61 FERC ¶ 61,138 (1993).

of new regional planning. Under the PJM Regional Transmission Planning Process, more than $4 billion of new transmission has been approved by the PJM Board. Similarly, under the MISO Transmission Planning Process, more than $3.6 billion has been approved by its Board.

Recently, RTOs have been addressing how to integrate plans to expand transmission for economic reasons, *i.e.*, transmission above and beyond that needed to satisfy the reliability criteria. Planning for so-called "economic" transmission is more difficult than reliability planning for several reasons. First, analyzing whether a proposed upgrade is, in fact, economic – that is, whether it will cost less than the congestion it is attempting to cure – depends upon a multitude of economic assumptions. Second, the analysis must consider the effect of any new transmission upgrade on the viability of existing generators and potential new generators. Third, new generation and load response compete as solutions to relieve transmission congestion. An independent third party such as an RTO is in the best position to assess the best solution to cure the congestion. Both PJM and MISO have filed new protocols for evaluating economic transmission upgrades.[13] These processes should enable new transmission projects to be built to enhance the economic operations of the transmission systems. ERCOT also has a process for evaluating and deciding on the addition of economic upgrades.

b. RTOs have reduced use of TLRs to manage congestion, relying instead on far more efficient redispatch of generation.

TLR or Transmission Loading Relief is a procedure that was developed by NERC to maintain the security of the transmission system by avoiding overloading transmission facilities. The procedure can be effective at avoiding overloads, but it is far from a perfect solution. First, TLR is a reactive procedure and takes time to work. Second, many times, if a transaction is partially curtailed, the customer will ask that the entire transaction be curtailed, as they cannot contractually manage a fraction of a transaction. Finally, TLRs are indiscriminate as to the economic value of the transaction being curtailed. A high-value transaction can be curtailed even when the customer would prefer to have a lower value transaction curtailed further to provide the same relief.

RTOs rely less on TLRs to maintain system security by using regional coordinated dispatch: (1) to prevent overloads in the first place; and (2) to redispatch generators when overloads appear imminent. Redispatch is a far more efficient way to avoid overloads because it occurs *before* the

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[13] *See PJM Interconnection, L.L.C.*, 117 FERC ¶ 61,218 (2006)(conditionally accepting changes); *Midwest Independent Transmission System Operator, Inc.*, Docket No. ER06-18-004 (Filed Nov. 1, 2006).

overload occurs and because it targets the generators with the most impact on the constraint to change their output.

A substantial efficiency gain attributable to RTO functions can be seen by the reduction in TLRs with the expansion of PJM. PJM expanded to include ComEd, AEP, and Dayton Power & Light during 2004 and Duquesne and Dominion in 2005. That expansion greatly increased the number of flowgates monitored, and therefore the potential locations for overloading, administered by PJM. Yet the number of TLRs called by PJM for Level 3 and above has dropped dramatically. MISO has experienced a similar phenomenon since its market opened in April 2005.

	PJM	% Decrease	MISO	% Decrease
2004	429	-	1,292	
2005	326	24%	1,291	>1%
2006	136	58%	800	38%

This shows the benefits not only in better utilizing the transmission system but also in avoiding curtailing transactions. RTO dispatch methods maintain the security of the transmission system more efficiently and more effectively.

c. Open access transmission and organized markets are best suited to add non-traditional resources.

Exelon's experience with the development of non-traditional resources in the service territories of our two distribution utilities – Commonwealth Edison or ComEd in Chicago and PECO Energy in Philadelphia – has led us to conclude that open access transmission and organized markets are best suited to add new, non-traditional generating resources and facilitate demand response programs.

As discussed above, in 1978 Congress enacted PURPA, a landmark piece of legislation that sought to encourage the development of non-traditional generating resources such as wind and solar power. For the first time, Congress gave FERC explicit authority to require transmission owners to provide access to their wires to designated "Qualifying Facility" resources in order to facilitate development of those resources. The PURPA program was not without its faults, particularly with respect to state implementation of its avoided cost requirements, which John Rowe has discussed. It did, however, pave the way for the concept of non-discriminatory open access to the transmission grid for third-party developers.

Now, nearly 30 years later, both the Congress and the States are reemphasizing the need for further development of non-traditional generating sources, principally to address concerns about global warming and greenhouse gas emissions.

Another witness at this Technical Conference, Michael Skelly from Horizon Wind, documented his own experience as a developer of wind projects and clearly stated that organized markets facilitate development of non-traditional resources. The American Wind Energy Association (AWEA) has documented the success story in restructured states vs. non-restructured states. We believe that AWEA's witness has amply demonstrated the success of wind development in RTOs. RTO regions with organized markets have over 70% of the wind development in the United States even though they have less than half of the wind potential. (See Appendix G.)

ComEd and PECO, which are both in RTOs with organized markets, have actively encouraged development of wind and other resources, and show a success story. Use of PECO's wind energy product has grown significantly since it was launched in 2004. The program has more than tripled in size growing from 10,000 customers after its first year to over 34,000 customers at the end of 2006. PECO's customers purchased over 100 million kWhs in 2006, which is the environmental equivalent of planting 8 million trees or not driving 100 million miles in your car.

ComEd purchased 130 MWs of landfill gas to energy generation and 50 MW of wind generation in 2006. ComEd also purchased over 160 thousand kWh of excess generation from customers with wind and solar generation through its Wind and Photovoltaic Program.

As of the end of 2006 Exelon Generation is the largest wholesale marketer of wind energy east of the Mississippi. Contracts with 150 MW of wind generation from four plants in PJM provided over 395 million kWhs that were sold on the PJM interconnection.

Pennsylvania's PennFuture, a citizens' organization dedicated to enhancing the environment of Pennsylvania, released its own report earlier this month and concluded:

> **Pennsylvania restructuring has led to a boom in clean energy development that has brought billions of dollars of new investment and thousands of new jobs. New generation companies have entered Pennsylvania. Projects that were previously impossible or very difficult when utilities had a**

monopoly are now operating. More and cleaner generation is benefiting both consumers and the environment.[14]

2. DON'T CREDIT ALLEGATIONS THAT COMPETITION HAS CAUSED ELECTRICITY PRICE INCREASES – THE REAL CULPRIT IS THE COST OF FUEL.

Electricity prices nationwide increased approximately 34% from 1999 to 2006, regardless of whether the state had restructured or not. Thus, the data show no correlation between the introduction of retail competition or the restructuring of utilities and electricity price increases.

On the other hand, the data are clear that the fuel mix used to generate power within the state does correlate to electricity price increases. During that same period, natural gas prices increased over 300% and coal prices increased close to 30%. Clearly, fuel price increases, not competition vs. regulation, drove electricity price increases.

Even so, electricity price increases have been, on average, lower than other energy products (*See* Appendix B). Moreover, notwithstanding electricity price increases in recent years, retail expenditures on electricity as a percentage of GDP are currently at 1972 levels, just about half of what they were in 1982. (*See* Appendix H.) And residential consumers are spending less than 3% of their median household income on electricity, which is near an all-time low. (*See* Appendix I.)

On the wholesale level, the impact of fuel prices also is very clear. A review of PJM data shows that the fuel-adjusted price over the past six years has declined despite record fossil fuel price increases. For the period April 1, 2006 thru December 31, 2006 the fuel-adjusted, load-weighted, average price in PJM was 9% less than the previous year from April 1, 2005 to March 31, 2006. ($17.8/MWh vs. $19.6/MWh.) And a comparison of 2006 wholesale prices to those of six years ago shows an even more dramatic decline in electricity prices – the fuel-adjusted, load-weighted, average price last year is 36% lower than the price from April 1, 1999 to March 31, 2000 ($17.8/MWh vs. $28.0/MWh).[15] This clearly demonstrates the value of the PJM expansion and its ability to reduce the system average heat rate, a measure of overall market efficiency.

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14 E^3, PennFuture, *It Just Isn't So* (Pt. 3), Vol. 9, No. 2 (Feb. 15, 2007).

15 *See* Appendix J, PJM Members' Committee, December 2006 Executive Report on Markets (2006), *available at* http://www.pjm.com/committees/members/downloads/20070125-item-03a-december-2006-executive-report-markets.pdf.

The Commission should not allow the recent run up in fuel prices in global energy markets to obscure the demonstrated benefits of RTOs and organized electricity markets.

3. DON'T REPLACE CLEARING PRICE ENERGY MARKETS WITH PAY AS BID.

We recognize that the competitive model is now increasingly under attack. Many recent analyses of the state of competitive wholesale electricity markets have pointed to increased prices for electricity and have "blamed" price increases on competition and, in particular, on single clearing price model. We believe the blame is misplaced. Moreover, economic experts uniformly recognize that single price markets are more efficient than other pricing mechanisms.

"Pay as bid" systems proposed as alternatives to single price clearing type market systems promote strategic bidding, rather than providing for bids that reflect suppliers' marginal costs. Pay-as-bid pricing causes suppliers to estimate their bids as close to the clearing price as possible as opposed to bidding to reflect their variable price. Professor Peter Cramton refers to this as a "Guess the Clearing Price" auction. This "guess" will result in dispatch inefficiencies because bidding will be based on other's bids as opposed to one's own costs, which will raise costs since higher variable cost units will be dispatched before lower cost units.

Exelon believes the PJM LMP market model represents the Nation's most advanced RTO model, though we advocate further enhancements to the PJM model in the form of increased liquidity, and more efficient dispatch and operations. PJM's LMP, security constrained economic dispatch with locational clearing price is recognized as an industry best practice. We have supported development of the Texas nodal market, which is also based upon an LMP style regime, as well as LMP-style markets in New England, New York and MISO. I am also encouraged to see that the California ISO and FERC have agreed that a key to emerging from the challenges of the California market failure is the establishment of a nodal based wholesale market in the form of the MRTU proceeding.

LMP provides price signals that make market participants partners with the RTO in maintaining grid reliability as they respond to market incentives. PJM reports that the recovery time in response to a system event is 30 times faster under market procedures because market incentives are far more targeted and effective than procedural rules such as TLR. LMP provides price signals that identify the degree of congestion to those considering long-term investment in new generation, transmission expansion of demand response options. LMP provides a dynamic market price which is an extremely valuable reference point for market participants

entering bilateral contracts to mitigate the price volatility inherent in a dynamic commodities market.

Without LMP, the management of congestion across a 14-state footprint like PJM would revert to first-come first-served transmission service and command and control system TLRs rather than generation redispatch. Don't abandon locational, bid-based, least-cost, security-constrained economic dispatch of generation, which selects the lowest price generation to satisfy the forecasted energy demand.

4. DON'T BE FOOLED BY THOSE WHO ARGUE AGAINST CLEARING PRICE MODELS – THEY ARE REALLY PURSUING VINTAGE PRICING.

There are those who argue it is unfair or improper for coal and nuclear plants to receive energy prices that are set by natural gas-fired units. Under the guise of "market power" (or other similar excuses), they seek to cap the revenue received by these units at levels more reflective of their incremental costs. Do not be fooled – these proposals are not mitigation of any legitimate market power concern. They are an effort to impose a form of price discrimination – sometimes called vintage pricing – which is a discredited policy. We do not support discriminatory or "vintage pricing" for generation. Such a pricing regime will inevitably lead to higher than efficient prices for certain generation sources, and commensurately lower prices for nuclear and coal, which in turn will lead to inadequate investment in baseload generating capacity – and higher costs overall. This is neither a new idea nor a good idea. The experience with vintage pricing in natural gas wellhead markets clearly indicates that vintage pricing will not restrain the retail price that consumers pay. Rather, it disproportionately rewards those resources that are not subject to price controls, while severely limiting returns on other resources.

5. DON'T ABANDON FERC'S STRONG ROLE IN POLICING DISCRIMINATORY PRACTICES.

In RTO procurements such as PJM's RPM capacity procurement, equal treatment for all generators – utility and non-utility, existing and proposed – remains a critical concern. PJM recognized this issue in the development of the RPM proposal. And equal treatment for all loads is just as important. So-called "carve outs" for loads served by vertically integrated utilities, such as attempts to make LMP "voluntary" for such load serving entities, will undermine central markets just as much as discriminatory treatment for generators.

In other wholesale procurements within the RTO footprint (but not run by the RTO), equal treatment for all suppliers – utility and non-utility, physical

and financial – is also a critical concern for FERC. For instance, a procurement that is restricted to new entrants would discriminate against existing generation. This would be a back-door method of avoiding paying market prices to incumbent generation. Even though a procurement run by a delivery company is state jurisdictional, the resulting wholesale contracts are FERC jurisdictional and FERC should not allow such a discriminatory pricing practice.

CONCLUSION

We strongly believe the development of RTOs with organized markets has shown demonstrable benefits as enumerated in this testimony. The Commission should seek to build upon the considerable successes of today's RTOs. Improve them, don't abandon them. Doing so will enhance reliability, reduce customers' costs, encourage investment in the array of generation sources we need to deal with the environmental challenges of the day, and continue to provide the resources we need for technology development to secure America's future.

COMPETITION: MYTHS AND FACTS

MYTH: Prices have increased in competitive markets more than they have in traditionally regulated models.

FACT: *Since 1999, electricity prices have increased 34% in both states with and without organized markets. Electricity prices are significantly affected by the cost for the fuels that run electricity generation plants. This is true in traditionally regulated jurisdictions as well as competitive market jurisdictions. Neither the competition model nor the cost-of-service model can shield customers from fuel price increases.*

MYTH: Single clearing price markets unjustly enrich generators and harm customers.

FACT: *Economic experts agree that a "single clearing price" approach is the most efficient way to establish market prices for electricity. Single clearing price markets reward power plant efficiency, offer the incentives necessary to attract new investments in a capital intense industry, and motivate consumers to conserve electricity – thus reducing the peak load and ultimately lowering the price of electricity by eliminating the need for the most expensive generation. The nuclear units that some now seek to "price cap" when market prices are high are the same nuclear units that sustained billions of dollars of write-offs and disallowance when market prices were low. This "Heads I win – tails you lose" process is not fair and will cause investors to flee our industry.*

MYTH: You need long-term contracts to get the "right kind" of new generation built.

FACT: *Our experience with centrally planned resources has led us to conclude there simply is no way to determine the "right kind" of new generation mix without putting customers' money at risk. Energy market prices provide the right signals for new construction so long as the rules are stable [predictable?] and fair. Mandatory long-term contracts require betting the customers' money on an unknown and unknowable future. The market is in a* *better position to take on the risks of uncertain fuel prices, environmental requirements, technology and construction costs. The market model may result in a different resource mix than the cost of service model – and that is to be welcomed.*

MYTH: Muni, coop, and industrial customers can't get long-term contracts.

FACT: *Long term supply contracts are readily available, but at a competitive market price. What the large customers are really complaining about is that prices have gone up. "Special deals" at below market rates are no longer available because they are no longer subsidized by other customers.*

MYTH: Generators exercise significant market power in RTO organized markets – and market prices are inflated as a consequence.

FACT: *False. Organized markets are carefully monitored and policed. In PJM, the market monitor has consistently reported that energy markets are workably competitive, and do not show evidence of market power abuse. The market monitor also has express mitigation authority, should the need arise. The structural problems of the original California model are well recognized and have not been repeated in other organized markets.*

MYTH: Competition jeopardizes reliability.

FACT: *There is simply no evidence that competition jeopardizes reliability. In reality, competition enhances reliability through increased generator availability and dramatic reductions in transmission loading relief (TLRs) where the system operator cuts transactions.*

MYTH: Competition causes congestion.

FACT: *Under competition, transmission systems are more frequently used to deliver distant low cost power to customers. It is well documented that more of this low cost power can be delivered over existing facilities thanks to organized markets and their pricing systems. Congestion is a sign of high use of the grid, and* *the prices indicate when and where the transmission system needs to be expanded or generation needs to be built.*

MYTH: Some contend that restructured companies aren't capable of running reliable systems and repairing storm damage; only "integrated" companies can.

FACT: *False. The statement is [both absurd and] offensive because it ignores the fact that crews from utilities like ComEd and PECO in restructured companies frequently help repair storm damage at utilities in integrated systems. The delivery side of the electricity business is a separate and distinct business function from generating electricity – even in an integrated company. Both ComEd and PECO run reliable systems, and industry metrics show that they consistently rank in the first and second quartile for reliability.*

MYTH: "Real" customers don't support competitive markets

FACT: *False. Many "real" customers, including many of the country's largest electricity consumers, believe they have benefited greatly from organized markets. For example, on December 4, 2006, some of the largest "real" customers in the Nation sent a letter to Chairman Kelliher endorsing competitive markets. The customers include 7-Eleven, Inc., A&P, the Archdiocese of Chicago, Best Buy Co., Inc., Big Lots Stores, Inc., the Chemistry Council of New Jersey, Federated Department Stores, and Wal-Mart Stores, Inc., and represent nearly 14,000 facilities with over $8.5 billion in annual electricity costs.*

MYTH: No one is building transmission.

FACT: *False. Between 2000 and 2006 Exelon (ComEd and PECO) has invested nearly $1 billion in transmission. ComEd's West Loop transmission project, which is currently under construction, is the most expensive and most complex transmission investment ever made by ComEd at a cost of $345 million. The Edison Electric Institute recently conducted a comprehensive survey entitled "Transmission Projects: At A Glance" (January 2007) that documents ongoing projects and recent investments.*

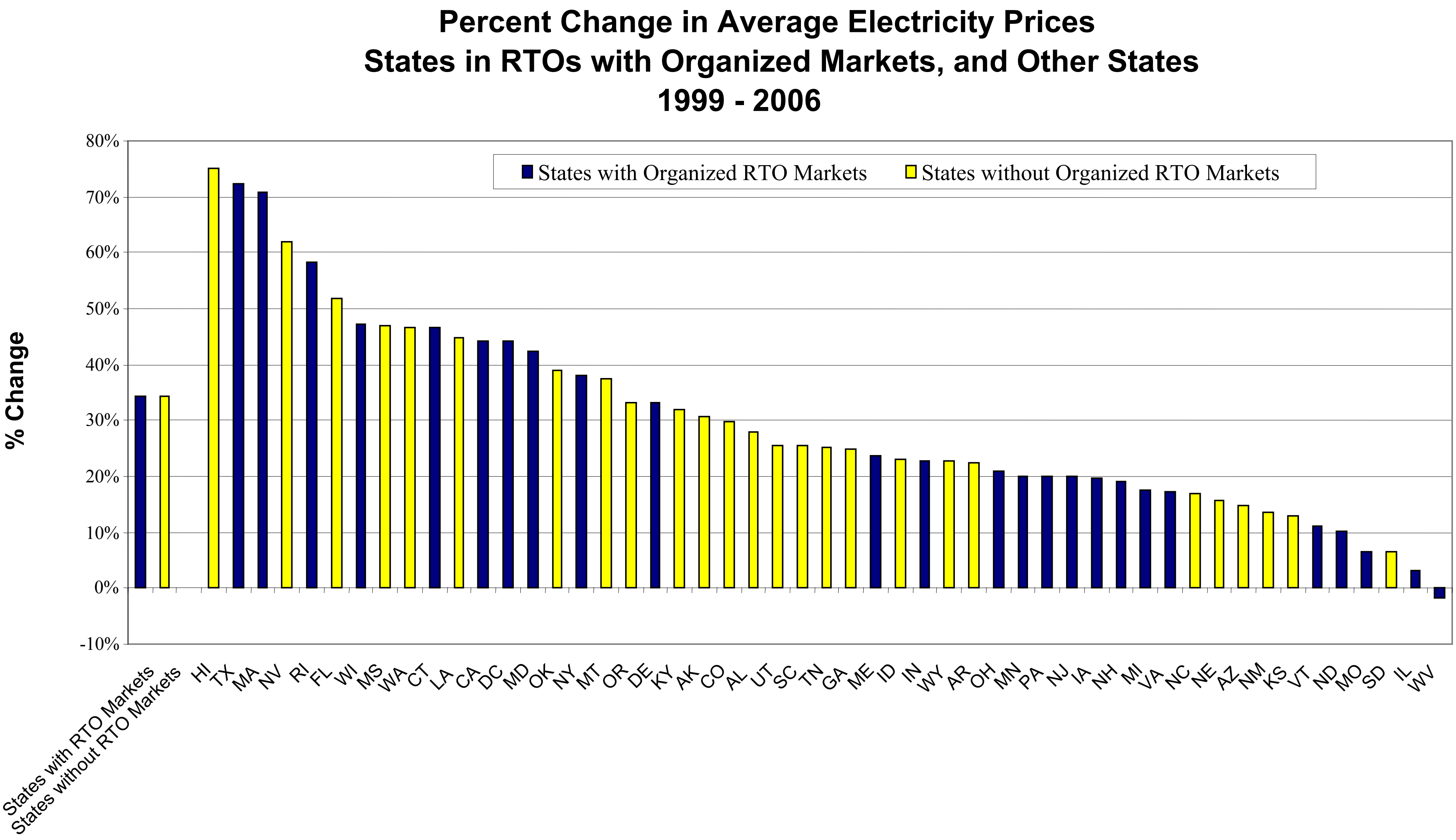
Conference on Competition in Wholesale Energy Markets

Appendices to Joint Statement of John W. Rowe and Elizabeth Anne Moler

Exelon Corporation

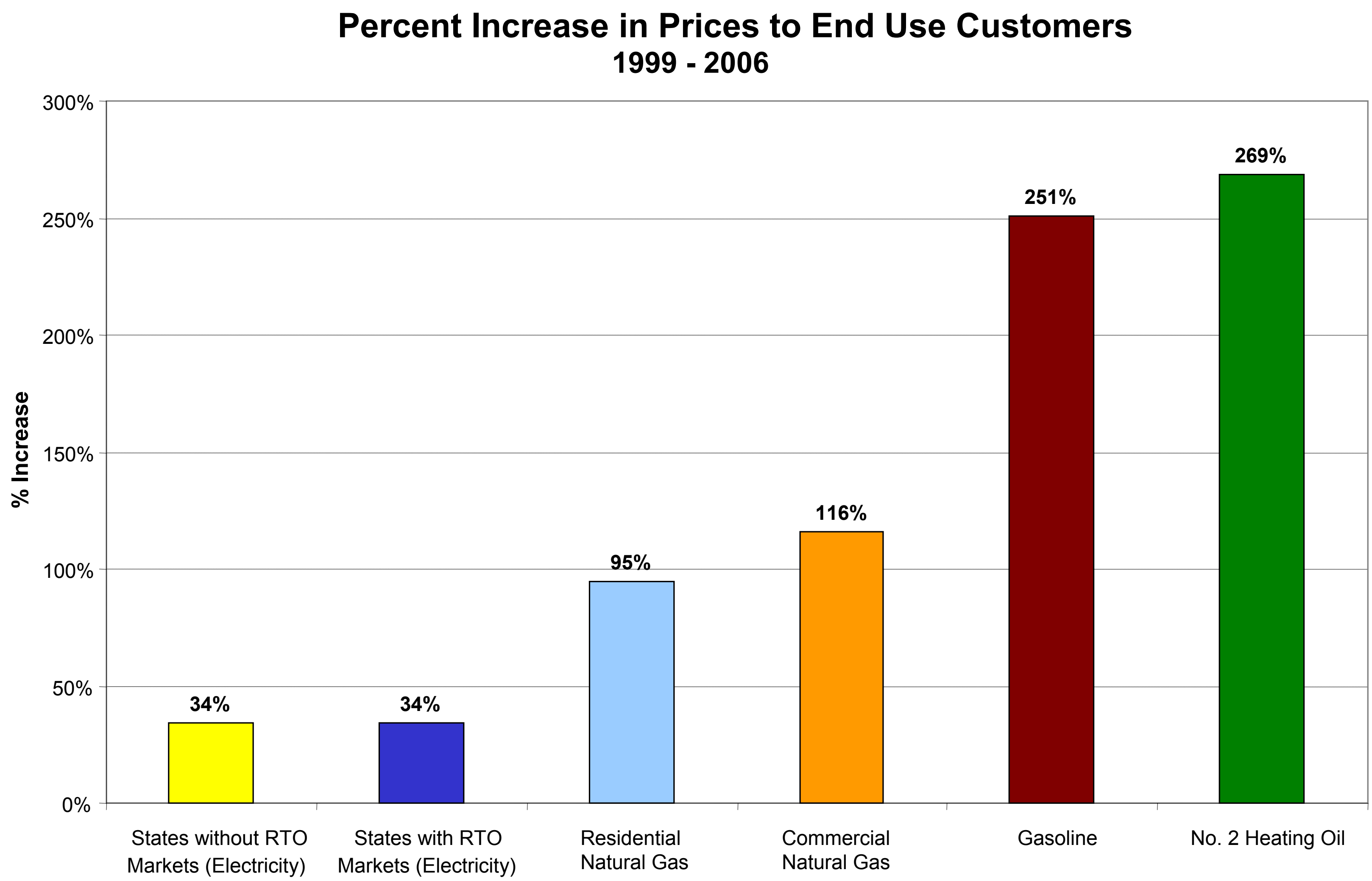
February 27, 2007

Appendix A – Price Increases by State



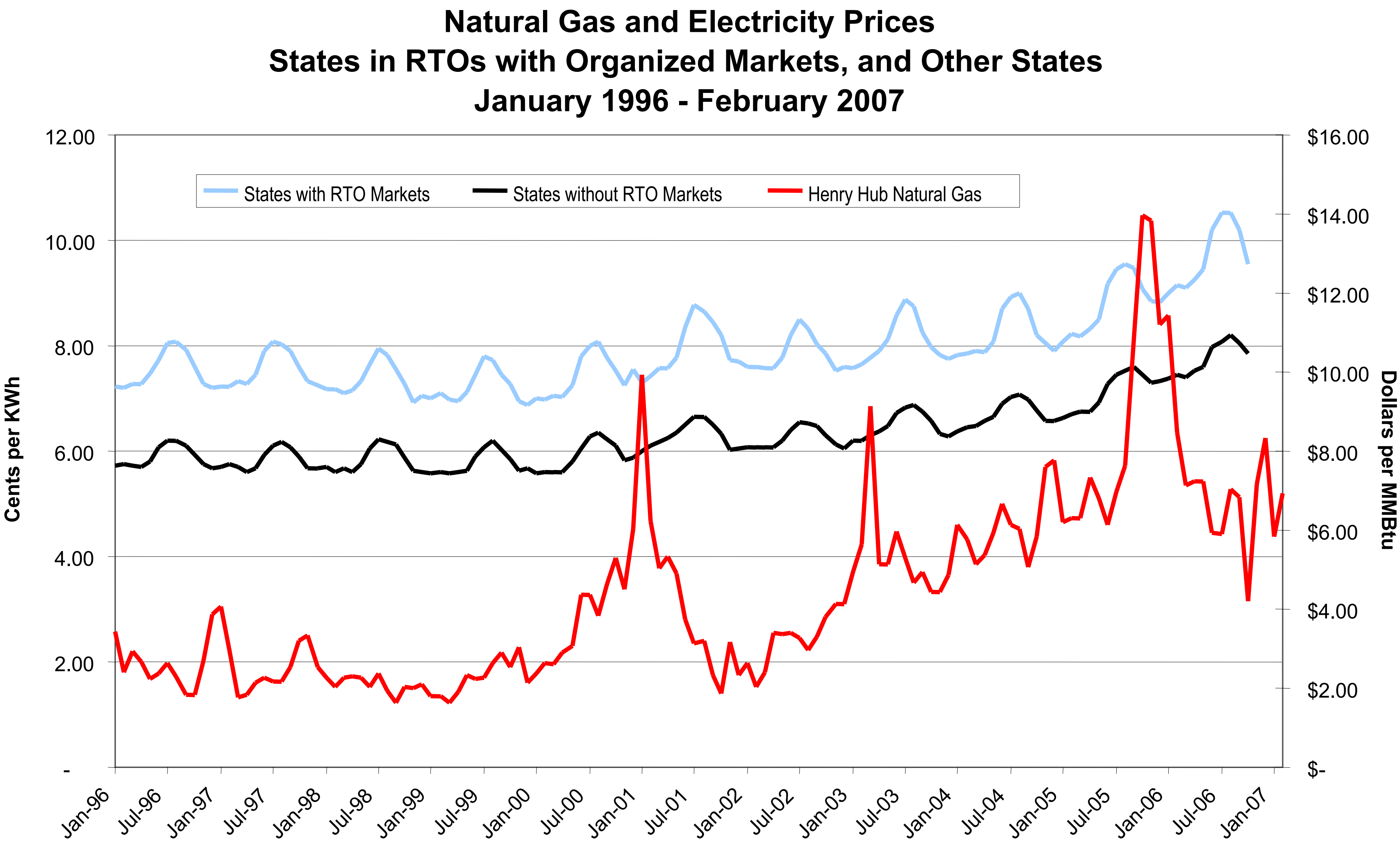
Source: EIA
Note: 2006 average prices reflect data through October.

Appendix B – Electricity vs. Other Energy Products



Sources: CPI data from BLS, all other data from EIA.
Notes: Natural Gas prices in 2006 are through November, electric prices are through October. All prices are annual averages of monthly data. No. 2 Heating Oil represents the New York Harbor price, Gasoline represents the Gulf Coast price.

Appendix C – Natural Gas & Electricity Prices

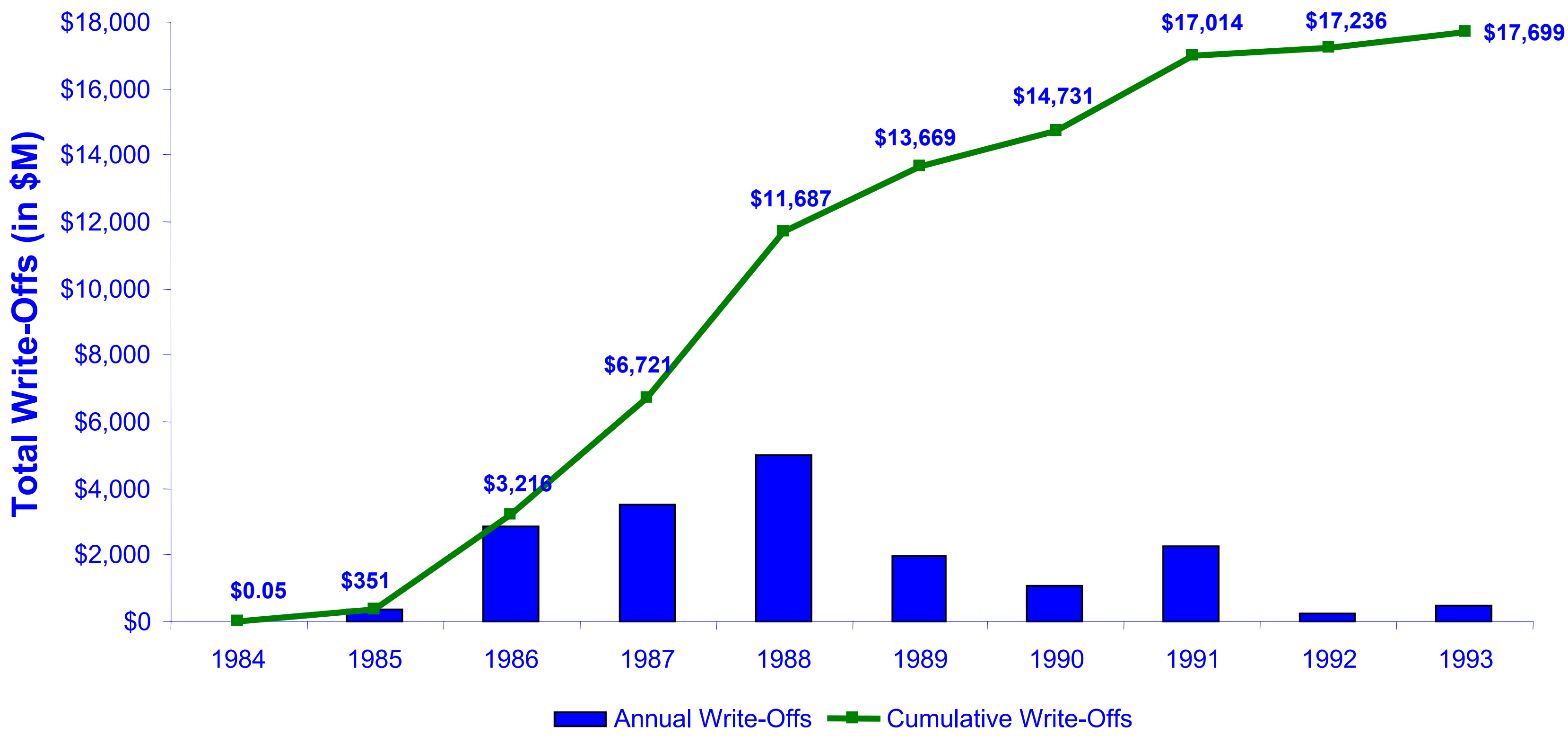


Source: Natural gas prices from NGI, electricity prices from EIA.

Appendix D – Nuclear Write-Offs in the U.S.

Write-Offs Related to Nuclear Power Plant Construction Projects 1984 – 1993

(amounts in $ millions, net of taxes)



Source: L. Ann Martin, Chandra Subramaniam, and Robert L. Vigeland, *The effects of SFAS No. 90 on Nuclear Electric Utilities*, November 1999.

Note: Represents write-offs related to disallowances or abandonments and does not represent later write-offs made for economic reasons.

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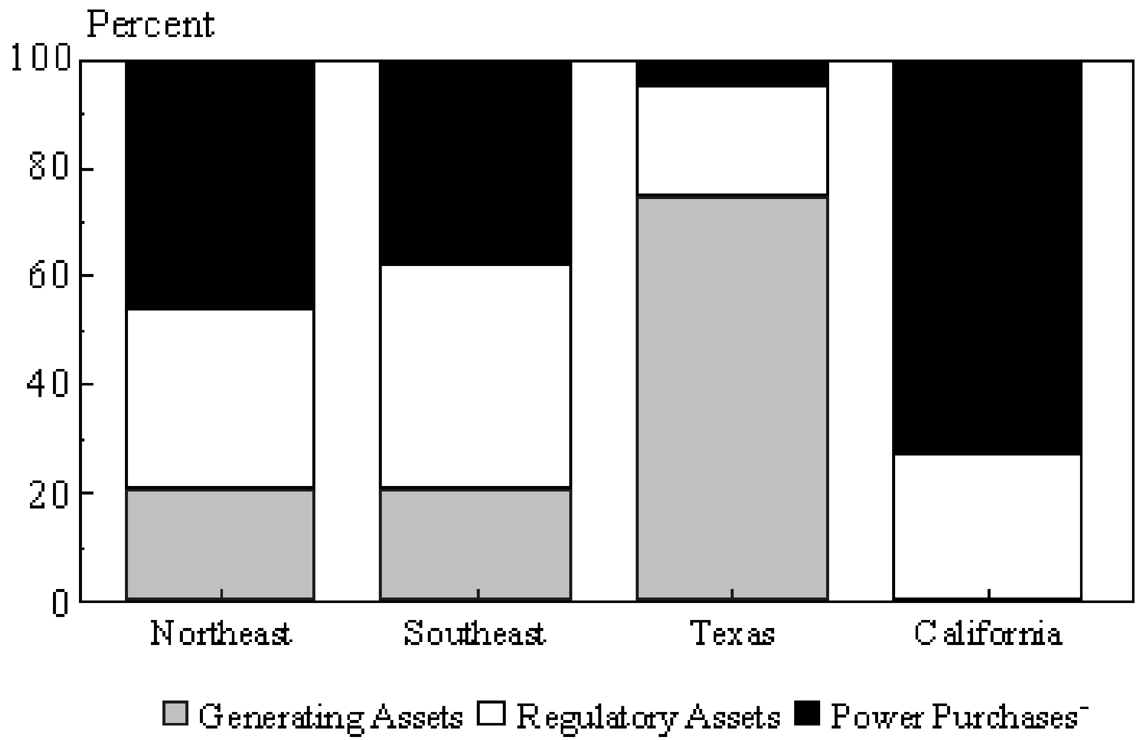
Appendix E – Sources of Stranded Costs in the U.S.

CATEGORIES OF STRANDED COSTS BY REGION

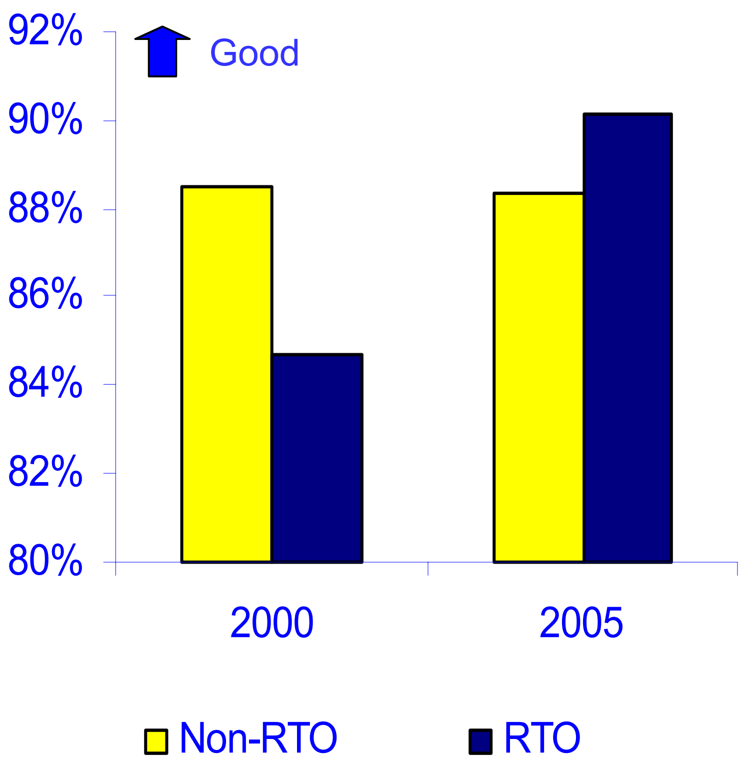


SOURCE: Congressional Budget Office based on data from Resource Data International.

NOTE: These numbers reflect net stranded costs after subtracting the costs of below-market generation facilities or power purchases. "Power purchases" include contracts mandated by the Public Utilities Regulatory Policies Act of 1978 (PURPA) as well as other power purchases by utilities.

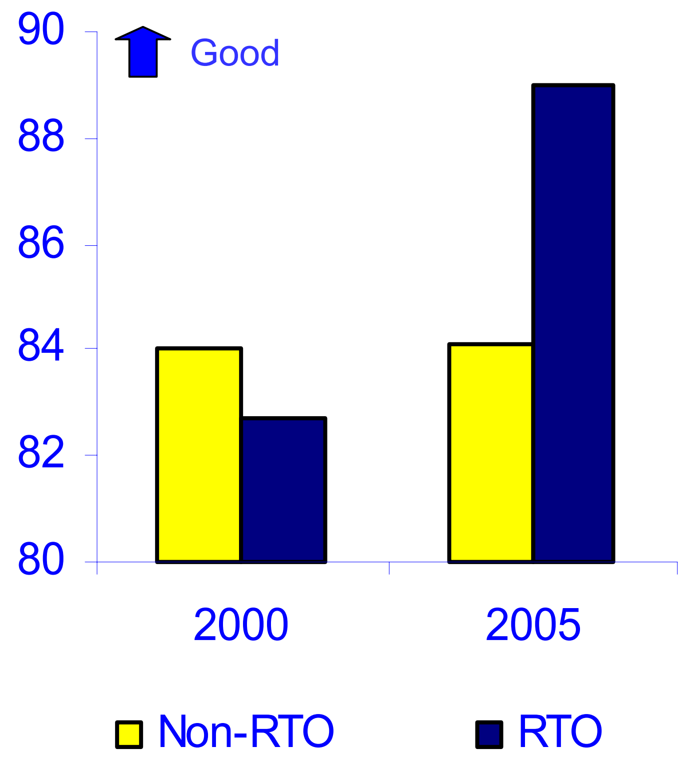
Appendix F – Nuclear Performance in RTO vs. Non-RTO States

Capacity Factor



Capacity Factor - ratio of the summation of generation (MWh) divided by the summation of MW rating during the number of hours in the period.

INPO Index



INPO Index - sum of the weighted product of the following indicators: unit capability factor, forced loss rate, unplanned automatic scrams per 7,000 hours critical, safety system performance indicator, fuel reliability, chemistry performance indicator, collective radiation exposure, and industrial safety accident rate.

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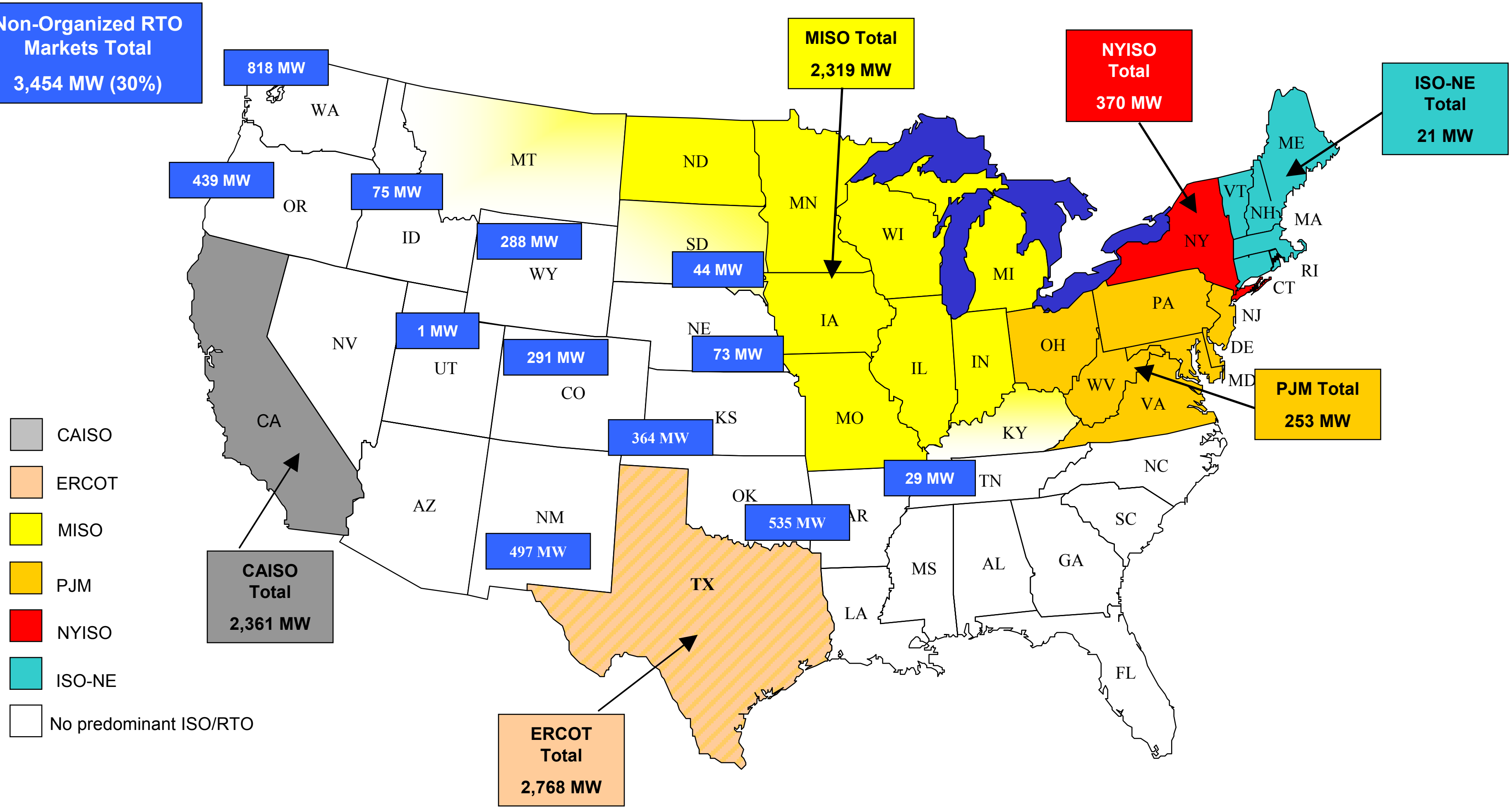
Appendix G – 70% of Wind Power is in RTO Markets

Organized RTO Markets Total
8,092 MW (70%)

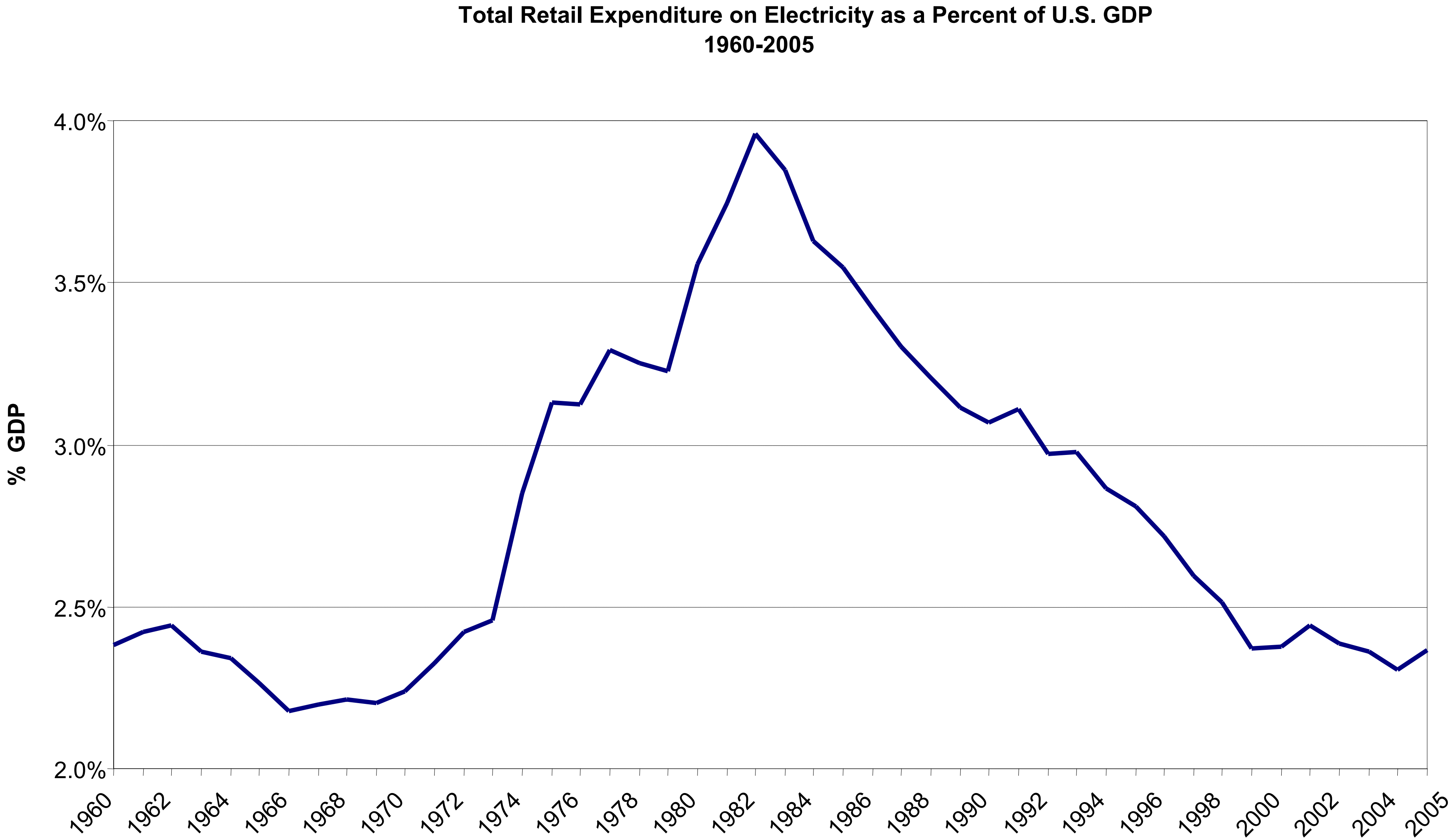
Non-Organized RTO Markets Total
3,454 MW (30%)

2006 Wind Power and Organized RTO Regions



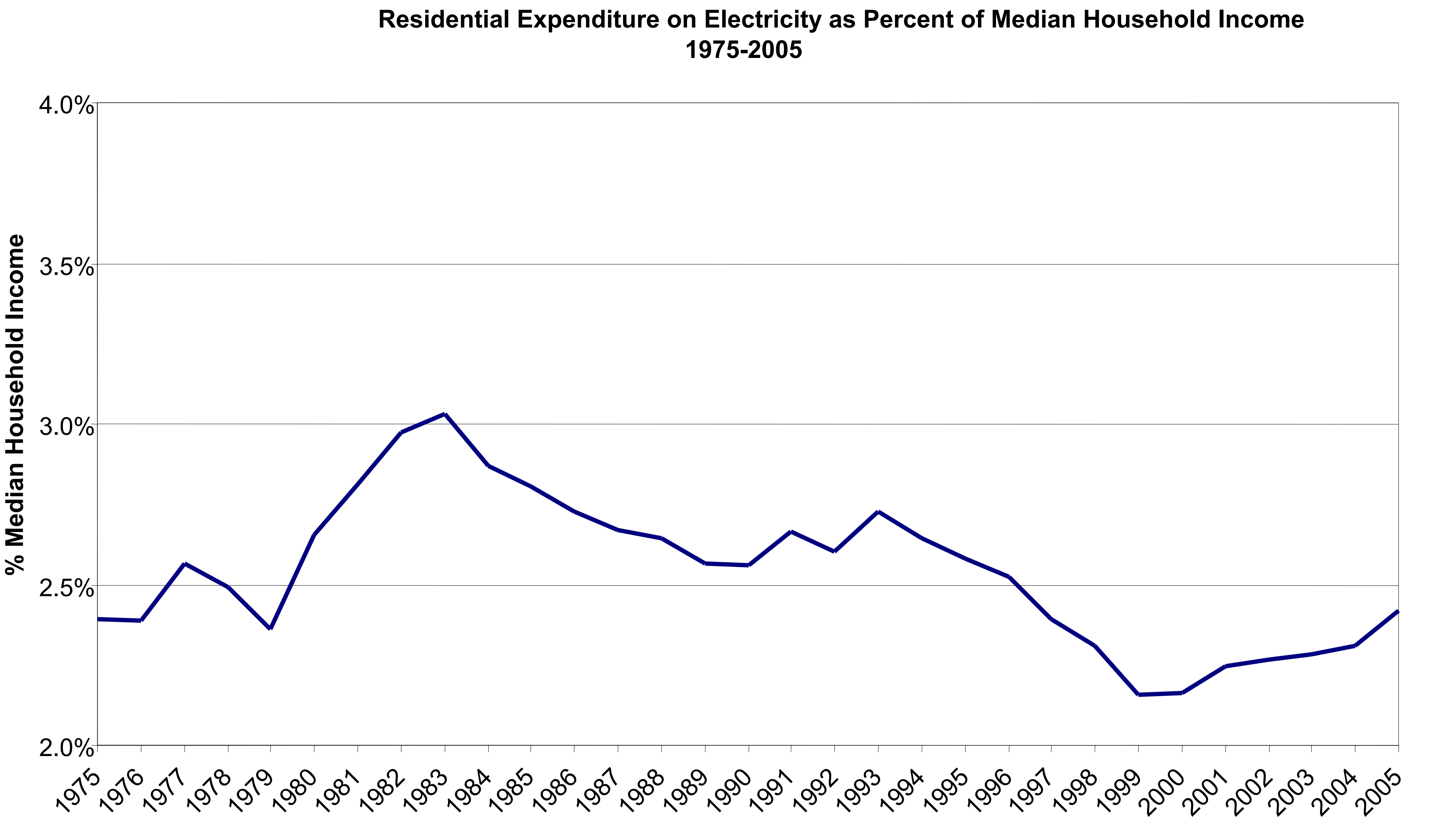
All numbers represent 2006 Year End Wind Power Capacity (source: National Renewable Energy Laboratory from American Wind Energy Association)

Appendix H – Electricity as Percent of U.S. GDP



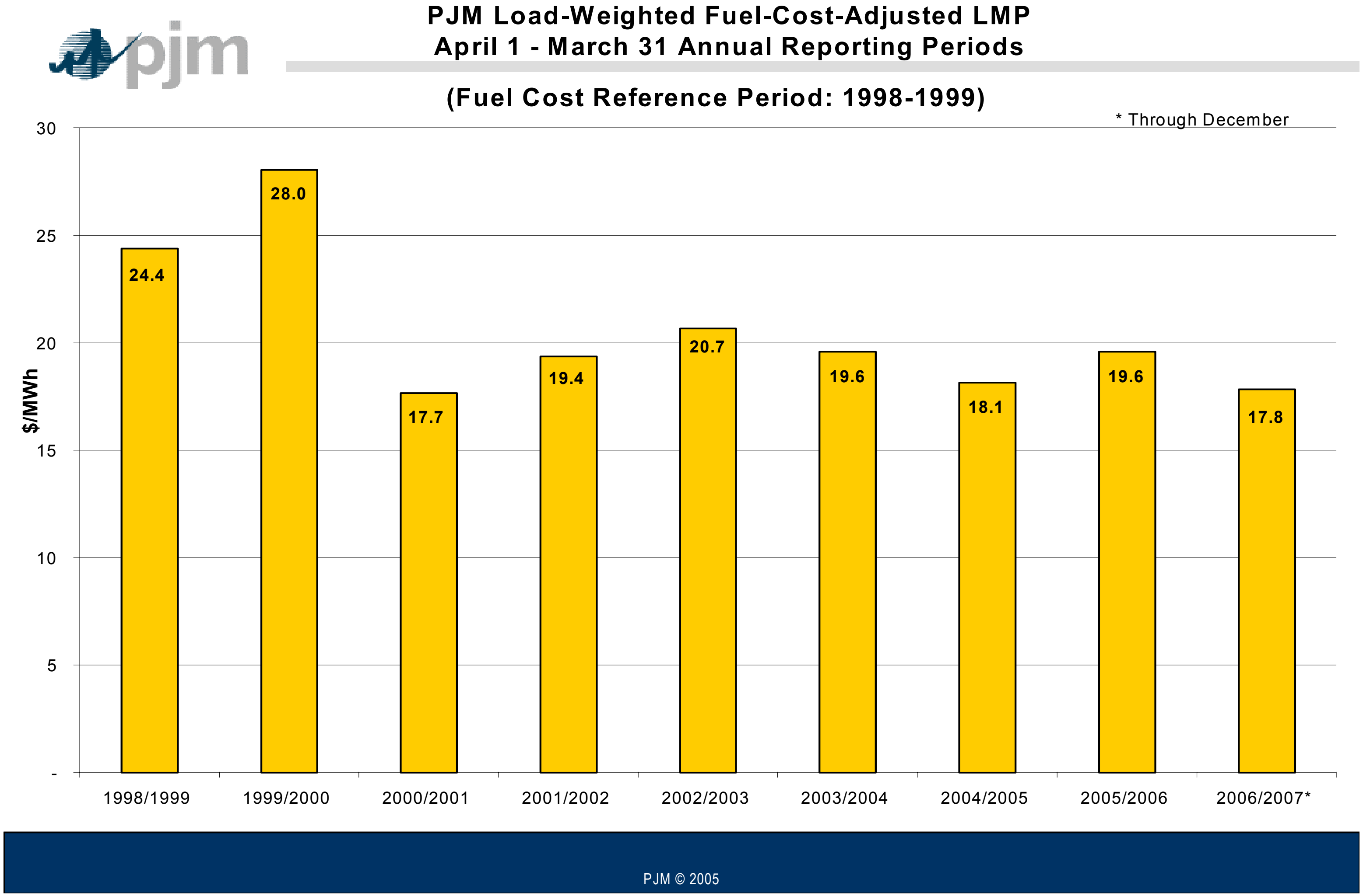
Sources: EIA, Annual Energy Review 2005, Table 8.9, Table 8.10, and Appendix D1.

Appendix I – Share of Household Income Spent on Electricity



Source: EIA, Annual Energy Review 2005, Tables 8.9 and 8.10; U.S. Census Bureau, Current Population Survey, Historical Income Tables, Households, Table H-6. Regions--All Races by Median and Mean Income: 1975 to 2005.

Appendix J – PJM LMPs, Adjusted for Fuel Cost Increases



Source: PJM Members Committee, 2006 Executive Report on Markets