ELCON Comments on ISO/RTO Costs

Submitted to the Government Accountability Office (GAO)
November 8, 2007

General Remarks and Perspective of ELCON Members

The Electricity Consumers Resource Council (ELCON) is the national association representing the interests of large industrial consumers of electricity. ELCON's membership spans the range of manufacturing sectors. Most ELCON members operate in global markets.

The typical ELCON member may have major facilities in more than one ISO or RTO, is served by more than one IOU in a regulated state, and also operates in global markets such as EU, Asia and Latin America. They experience the different costs of doing business across these different markets and regulatory regimes on a day-to-day basis.

The "costs" of ISOs and RTOs are multi-dimensioned. It includes fees used by ISOs and RTOs to recover its investment and operating costs, the cost of participating in ISO/RTO stakeholder process (including interventions before FERC and state PUCs on ISO/RTO affairs), and the additional costs imposed by the markets operated by ISOs/RTOs that do not exist in regions without ISOs or RTOs.

- ISO/RTO Fees, Charges & Cost Adders: Since the costly inception of the California ISO, industrials have had to fight attempts by ISOs and RTOs to find "deep pockets" for the recovery of their "uplift" costs. For example, the CAISO created fictitious uses of its system in order to spread its growing costs over a wider field. One approach attempted by the CAISO was to identify new uses of its services on the other side of the customer meter. CAISO claimed that on-site generation was functionally scheduled to the ISO and back again to the load and therefore each component of the "wash trade" should be assessed a fee. The fact is that the electrons never left the site. The CAISO currently has over 100 "charge types" for assessing its costs to market participants. Related experiences are replicated with each ISO/RTO formation.

- Stakeholder Participation Costs: Industrials have generally given up on attempting to influence market design changes and other reforms to the ISO/RTO concept. Instead the focus of their limited resources is defense. The expected benefit of covering the myriad of stakeholder committees, subcommittees, task forces and working groups is perceived to be nil, while the costs in time, travel and legal expenses can be staggering. This point is covered in more detail below.

- Costs of Buying Power from ISO/RTO Markets: Industrials are galled by the fact that ISO/RTO markets generally provide inferior products and services compared with the previous regulatory regime notwithstanding the widely recognized inefficiencies of regulation. Replacing the regime of rates based on average costs with prices based on marginal costs, while theoretically correct for enabling competitive forces to drive efficient investment and operating decisions, has not enabled the superior products and services expected of competitive markets. The market design and pricing mechanism is incompatible with the high level of residual market power exercised by utility holding companies.

GAO Questions

Describe primary startup and operating costs of ISOs/RTOs and key factors driving these costs. Have ISO/RTO costs changed over time? If so, how? What factors are responsible for these changes?

Answer:

ELCON supports the efforts of the American Public Power Association (APPA) to examine and expose the costs incurred by ISOs and RTOs. See: APPA, *Analysis of RTO Operational and Administrative Cost of RTOs,* February 5, 2007.

Our understanding of primary ISO/RTO startup costs and operating costs is as follows:

Startup costs

- Search process for board of directors, senior officers
- Staffing and recruitment costs
- Acquire real estate and facilities for control rooms, staff and stakeholder meetings
- Need for duplicate control centers
- Hardware/telemetry design and acquisition
- Extra costs for control area consolidation
- Software development
- Stakeholder meetings and conference space
- Legal expenses of FERC filings

Administrative & Operating Costs

- A&G Salaries, bonuses and benefits
- Rent/mortgage/debt payments
- Operations & Dispatch
- Ongoing software and hardware development in response to FERC orders
- Legal/regulatory expenses
- Consulting fees and other outside services
- Meeting expenses

The "cost drivers" that we believe account for recent concerns about ISO/RTO budgets and may drive future budget increases are the following:

- Mission creep and the desire of ISOs and RTOs to be all things to all potential stakeholders.[1]

- ISOs and RTOs have an odd non-profit corporate structure with loosely defined lines of accountability. In regions of the country where they exist, they have typically replaced the traditional investor-owned utilities (which were subject to state regulatory oversight) as the central feature of the industry. The original intent of ISOs was to further "unbundling" of the industry as a prelude to competition. Ironically existing ISOs and RTOs have rebundled most operational and planning functions of vertically-integrated utilities except actual asset

[1] For example, some ISOs and RTOs have initiated activities related to renewable energy and climate change.

ownership. This separation of ownership from operational control dilutes the normal means of cost accountability.

- Each ISO/RTO organization's budgeting process is external and effectively hidden from normal legal oversight requirements between regulators and their jurisdictional entities. FERC's oversight of ISOs and RTOs has not been as vigilant as it should be because the agency has a conflict of interest that can be attributed to its "pride of authorship." FERC created ISOs and RTOs in two so-called "landmark" decisions: Order No. 888 (75 FERC ¶ 61,080) and Order No. 2000 (89 FERC ¶ 61,285).
- FERC's "Day-Two" market design for ISOs and RTOs have been implemented on a trial-and-error basis. The evolution of each ISO and RTO's market design has thus become almost unending. This is necessary because of unintended consequences of locational pricing and residual market power of utility holding companies. The 2000-2002 California debacle illustrates the dilemma. The market power of suppliers made the "scarcity pricing" feature of locational pricing unpalatable to state regulators (and later FERC). Elimination of scarcity pricing with price caps and mitigation resulted in inadequate compensation to marginal generating units—but only to a small number of generators. Trying to fix this problem led to overcompensation for generators that are not the marginal units, creating a backlash from states and consumer groups.
- Officer/staff turnover. Rural/exurban locations do not attract talent except at premium salaries and costly arrangements for commuting. Each ISO and RTO's default recruitment choice tends to be former utility employees.
- ISOs and RTOs are dependent on expensive outside services (legal and consultants), in part, to compensate for shortage of in-house talent.
- ELCON fears that growing attention on cyber security concerns will greatly expand future budgets. The economic pretense for larger and larger control areas (to increase scope of markets) magnifies the security risk and this risk will be costly to mitigate.[2]

Please describe the key benefits of ISOs/RTOs. How do the benefits achieved by these entities compare to those FERC envisioned in its Order 2000 (increased efficiency in transmission grid management, improved congestion management, more efficient planning for transmission and generation investments, improved grid reliability, etc.)?

Answer:

From a consumer perspective, there are no discernable benefits of having ISOs or RTOs. They have become an additional layer of regulation, bureaucracy and costs that is imposing substantial transaction costs on companies, their legal staffs and advocacy groups (e.g., ELCON).

Even if the price debate is a wash, the existence of ISOs and RTOs has not contributed to other expected benefits of competition such as (1) innovation, (2) improved customer service, and (3)

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[2] Control areas represent a portion of the grid that is under unified, real-time control. Its basic function is to balance loads with resources. When an imbalance occurs (inadequate supplies to meet expected load), the first line of defense after the control area's own "reserves" are used is to draw on the resources of neighboring control areas. As control areas increase in size, there is less "security in numbers." This risk appears to be getting the attention of the US Department of Homeland Security.

mass media marketing of ANY benefit as experienced in other formerly regulated markets such as telecom and airlines.

ELCON members operate in multiple states, regions and countries. Many operate in more than one ISO or RTO and in regions not served by ISOs or RTOs. They see absolutely no benefits in terms of either relative cost savings (RTO prices versus non-RTO rates) or consumer satisfaction with non-price factors. The results of customer satisfaction surveys of large end-users ("large key accounts") by a nationally recognized research firm show that the failure to achieve these expectations has significantly changed the way that large consumers view restructuring. Specifically, for the past nine years, the customer service scores in regulated states are considerably higher than those in states served by ISOs or RTOs for every factor measured in those surveys.

ELCON submitted comments to FERC in March 2007 that addresses these issues in more detail and with data to support our claims. A copy of those comments is attached.

ISOs and RTOs were intended <u>solely</u> to be a platform for competition—especially retail competition. That has not happened, and perhaps in order to save face, FERC and ISO/RTO staff are struggling to defend continued existence of these entities. The existence of a battle of consultants for estimating benefits or lack thereof is compelling evidence that ISOs and RTOs are far from an obvious success. The industry today is plagued with the following problems:

- Inability of high prices to stimulate any investments, in fact, the market design and pricing mechanism creates powerful economic disincentives to real competition.
- Unwillingness of transmission owners to invest in infrastructure for economy purposes. Such facilities might make the ISO/RTO market design work in practice by alleviating congestion. It is in the economic interests of generators to increase congestion because the greater the congestion, the higher the average market clearing price which is paid to all generators.
- There is no credible resource planning for generation or transmission. FERC and the states are fighting over which venue has authority to determine resource adequacy. The "market" was supposed to do this but market entry barriers prevent it. The industry is currently bogged down by FERC's plan-to-plan initiatives. Example: FERC <u>Order 890</u>, which ordered regional coordination of transmission planning.
- Implementation of electricity prices based on marginal prices created huge windfalls for incumbent utility holding companies. They have been very successful in lobbying to preserve the status quo because FERC and ISO/RTO staff also have vested interest in preserving the status quo. This hiatus is inducing many states to take unilateral actions to fix the markets within their state boundaries, which is only creating less effective and disorganized markets.

ISOs and RTOs were developed without any serious thought given to the necessary pre-conditions for competition in the US electric industry. ELCON was written two papers on the necessary pre-conditions. The latest paper has already been distributed to the GAO review team. In a series of meetings with FERC commissioners in 2001, ELCON challenged FERC to demonstrate that one ISO or RTO could be made to work as intended (and get the market design right) before attempting to impose RTOs on other regions of the country, but we were dismissed as heretics.

Have ISOs/RTOs helped achieve FERC's goal of promoting efficiency in wholesale electricity markets and ensuring that electricity consumers pay the lowest price possible for reliable service? If so, how? If not, why not?

Answer:

Where control areas were consolidated or expanded, unit commitment and dispatch probably improved in efficiency relative to pre-existing (smaller) power pools (e.g., PJM and NEPOOL) or areas without pools (e.g., Midwest ISO, ERCOT and CAISO). The implementation of marginal pricing has kept these relatively small benefits to be shared with electricity consumers. Note that ELCON expected marginal pricing in a competitive market, but got marginal pricing in a regulated RTO market. The higher prices were intended to send price signals to stimulate investment (e.g., elimination of transmission congestion) that would offset the higher marginal costs.

There is also clear evidence that the availabilities of nuclear plants have increased. It is unclear if those efficiencies were the result of utility owners' anticipation of competition or the result of the implementation of marginal pricing with higher natural gas prices clearing the market for all generators. This was an unintended consequence of generation divestiture in restructured states. Remember the owners of those generators received substantial stranded costs in anticipation of a market in which those units could only sell its output at prices lower than rates based on average costs. Consumers have not seen the benefits of these increased availabilities under locational pricing.

To what extent are electricity stakeholders and FERC involved in the ISO/RTO decision-making process? What, if any, influence do they have over ISO/RTO costs and decisions?

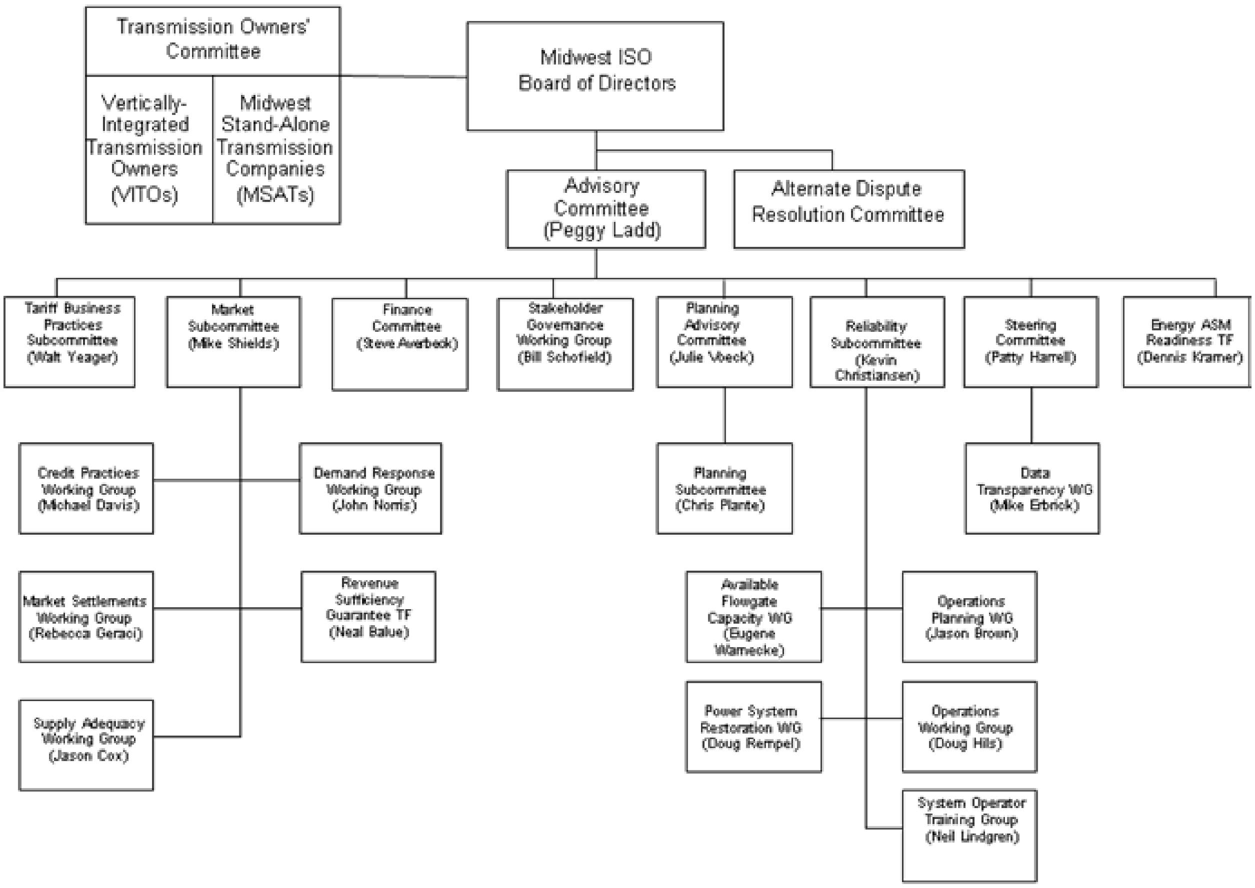
Answer:

Stakeholder involvement with ISO/RTO decision-making is best understood in the context of how stakeholders are forced to interface with an ISO or RTO. Consider the Midwest ISO. The Midwest ISO currently has 29 active stakeholder committees (variously called committees, subcommittees, working groups and task forces). See chart on next page. MISO also has 17 inactive committees, some of which can reactivate at a moment's notice. In November 2007, the ISO scheduled 65 meetings over 17 business days (out of a total 20 business days in the month)—an average of almost 4 meetings per business day. Some meetings (6) were cancelled and rescheduled. Seventeen (17) were meetings that provided training to stakeholders. This highlights the burden on stakeholders. A typical ELCON member may operate in two or three ISOs or RTOs. They are forced to triage participation with other companies and local groups for basic defense purposes. Participation is dominated by stakeholder entities such as utilities who can automatically recover from ratepayers their expenses to attend meetings (and often task employees with no other responsibilities).

ELCON staff has first-hand experience with one small working group (SAWG). Industrial consumer participation in that group rotated among 3 state groups and one large (Indiana) company. Several MISO states had no industrial representation. By comparison, several utilities (DTE and Ameren) sent as many as 3 to 6 people to each meeting. Meeting agendas dominated by PowerPoint presentations ("status reports") of MISO consultants. No decisions were made at the meetings. ISO staff listened and defended their internal decision making. The real process starts when the ISO makes a FERC filing, but many such filings are routinely rubber-stamped by FERC because of the agency's assumption that the filing already "had stakeholder input." Controversial issues (e.g., capacity market formation) have tended to explode during adjudication, often forcing settlement processes. Efficient markets cannot be designed by contentious settlement processes in which the lawyers outnumber the economists.

Committee Structure of the Midwest ISO

As of November 2007



29 Active Committees

17 Inactive Committees

Meetings Scheduled in November 2007

Meetings scheduled on 17 out of 20 total business days in the month

65 meetings scheduled

6 were cancelled (and rescheduled)

17 were stakeholder training sessions

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Conference on Competition in Wholesale Power Markets	Docket No. AD07-7-000

Supplemental Comments of the Electricity Consumers Resource Council ('ELCON')

The following comments are submitted to supplement the prepared remarks of Dr. John A. Anderson. These comments respond in detail to the issues raised in the Commission's February 9, 2007 Supplemental Notice on the conference.

ELCON was perhaps the earliest national group to advocate increased competition in the electric utility industry. Our members operate in competitive global markets and appreciate the efficiencies of open competition compared with poorly regulated centralized markets. However, after roughly a decade of experience with restructuring there are clear indications that the FERC-approved ISO and RTO markets are too costly, not truly competitive, and fail to deliver net consumer benefits.

Summary

In December 2006 ELCON issued a white paper that reaffirmed the organization's desire for real competition in the electric industry, but also stated in no uncertain terms that real competition simply has not happened. Despite an attempt to design a wholesale market structure consistent with economic theory and capable of supporting real competition, the design that was actually implemented was short changed, creating the need for frequent regulatory intervention. The paper identified seven necessary and essential pre-conditions that must be acted on in a coordinated and integrated manner to make wholesale markets truly competitive. These action items are: (1) treat price-responsive load as a resource that is compensated on the same basis as generation and integrate demand response in the price-setting mechanisms, (2) eliminate centralized capacity markets and other regulatory fixes that are inhibiting new investment in the industry, (3) eliminate the rent-seeking ability of RMR generators with their threats to bring down the grid, (4) establish long-term forward contracting as the dominant form of transaction between suppliers and loads or LSEs, (5) resolve the unintended consequence of locational pricing to discourage generation and transmission infrastructure investment, (6) resolve the market power of joint owners of generation and transmission, and (7) eliminate regulatory intervention in spot price formation once the other six pre-conditions have been successfully implemented.

ELCON recommends that FERC acknowledge that its Day Two market construct is not working for the benefit of end-use consumers as required by the Federal Power Act; that the Commission initiate an inquiry into whether today's RTO platform, with locational pricing, can be made a viable market model for real wholesale competition; acknowledge the magnitude of the problem and recognize that simple technical fixes or additional regulatory intervention will not correct the inherent problems; and acknowledge that if these pre-conditions cannot be achieved that the policy debate shift—under FERC leadership—to what form of regulation is appropriate to deal with the unique challenges of the electric industry.

A. The Fundamental Objective of Competition Was To Deliver Net Benefits To End-Use Consumers

The defenders of the status quo who disagree with us bear the burden of showing real evidence that competitive power markets have provided consumer benefits. We would like to see the innovations, the improved customer service, or the so-called 'killer' products that everyone wants and that would have already been delivered in a truly competitive market. But the defenders of the status quo can't show us any of these because they simply aren't there. Real competition has not been realized. Restructuring has replaced the old state regulatory regime that had at least some end-user focus and rates based on average costs with a costly ISO/RTO federal regulatory regime that has no end-user focus and rates based on the highest accepted bid, which need not be based on marginal cost. A reasonable expectation would have been that competitive markets would deliver greater benefits to end-use consumers than regulated markets.

The results of customer satisfaction surveys of large end-users ('large key accounts') by a nationally recognized research firm vividly show that the failure to achieve these expectations has significantly changed the way that large consumers view restructuring. Specifically, for the past nine years, the customer service scores in Regulated States are considerably higher than those in Deregulated States for every factor measured in those surveys. This is shown in Tables 1 and 2 on page 5. All factors improved in the Regulated States, but there has been very little improvement in the Deregulated States with the exception of Account Manager and Price Satisfaction. This is shown in Table 3 on page 6. Note that the results for improvements in 'Price Satisfaction' are the same (9%) in Regulated and Deregulated States. This tends to contradict the argument that large industrial dissatisfaction with restructuring is solely the result of large price increases. The survey results paint a more complex picture that is counter-intuitive if some degree of real competition had emerged in the Deregulated States. Table 4 shows specific attributes with the largest performance gap between Regulated and Deregulated States. One would expect that with only a small amount of real competition—and greater customer focus—the scores would be higher in the Deregulated States. What is particularly disconcerting are the poor scores in Deregulated States for assistance in adopting new electro-technologies and other energy efficiency measures. There was much discussion during the February 26 conference on the need to address growing environmental concerns and there was a common presumption that competition had the potential to encourage greater energy efficiency. This has not happened in Deregulated States based on these survey results. Table 4 indicates that large customers receive better assistance with the adoption of new electro-technologies and being energy efficient in Regulated States, and by wide margins (25 and 24%, respectively).

The present-day ERCOT market differs from the FERC-approved organized markets in many respects, but the following features are important for many ELCON members with facilities in Texas that sets apart the ERCOT market from FERC-approved organized markets.

First, the present-day ERCOT market does not use nodal pricing and provides for bilateral forward contracting without a centralized pool or installed capacity market. Loads with rights to shop are not forced into a spot market or accept 12 to 24 month contracts that merely pass-through spot prices plus a premium. This encourages generators to deal directly with end-use customers, a situation that does not exist (for example) in PJM.

Second, ERCOT treats demand response as a legitimate resource and compensates it at market value. This includes that aptly named products 'Qualified Balanced Up Load (BUL)' and 'Load Acting as a Resource (LaaR)', which are load-based resources capable of providing balancing energy and operating reserves, respectfully.

Third, the degree of real competition in the market is sufficient to make industrials with qualifying cogenerators indifferent to PURPA, a condition that does not prevail in any FERC-approved organized market. Generation interconnection is also easy and friendly to the generator—including customer-owned generators.

Fourth, transmission adequacy was substantially assured before commencement of market operation and ERCOT does not have the huge problem created by Reliability-Must Run (RMR) units that plague FERC-approved organized markets, and the market power of joint generation and transmission ownership is also more temperate as a result. The cost of Texas' aggressive investment in new transmission infrastructure was socialized in rates paid by all loads, which prevented the debate over cost responsibility from stopping investment altogether.

TQS Research, Inc.
2006 National Utility Benchmark
Service to Large Key Accounts[1]

Table 1

Comparing Overall Satisfaction in Deregulated States to Regulated States									
Status of Deregulation	**1998**	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**
States Not Active	64%	64%	67%	67%	71%	71%	71%	73%	76%
States on Hold	59%	57%	65%	58%	63%	66%	60%	67%	62%
Deregulated States	55%	53%	55%	54%	52%	54%	56%	57%	57%

Table 2

2006 Customer Service Factor Scores			
	Regulated States	**Deregulated States**	**Gap**
Overall Efficiency	67%	43%	24%
Overall Satisfaction	76%	57%	19%
Overall Handling Contact	77%	60%	17%
Power Quality	82%	68%	14%
Overall Reliability	83%	71%	12%
Overall Price Satisfaction	54%	41%	13%
Overall Satisfaction with Account Manager	92%	83%	9%

[1] Reproduced with Permission of TQS Research, Inc., Atlanta, GA. Beginning in 1994, TQS Research, Inc. has interviewed the largest energy users in the US concerning their perceptions of their electric suppliers. The population consists of manufacturing customers over 1 MW, hospitals over 3 MW and major universities over 10 MW. The results of approximately 6,000 interviews per year allow TQS to provide the Electric Utility Industry with a Benchmark indicating their performance relative to approximately 60 other electric utilities. This approach allows TQS's clients to compare their results on 61 questions to the results of the other suppliers in the US. These questions cover the overall measurements of Customer Satisfaction, Loyalty, and Value. They also cover the functions measuring Energy Efficiency, Price, Reliability, Power Quality, Account Manager Performance, Handling Customer Inquiries, and Image.

TQS Research, Inc.
2006 National Utility Benchmark
Service to Large Key Accounts

Table 3

Factor Trends in Regulated States Compared to Deregulated States						
	Regulated States			Deregulated States		
	2006	1998	Improvement	2006	1998	Improvement
Overall Efficiency	67%	50%	17%	43%	43%	0%
Overall Reliability	83%	75%	8%	71%	71%	0%
Power Quality	82%	69%	13%	68%	66%	2%
Overall Price Satisfaction	54%	45%	9%	41%	32%	9%
Overall Satisfaction with Account Manager	92%	79%	13%	83%	76%	7%
Overall Handling Contact	77%	65%	12%	60%	63%	-3%
Overall Satisfaction	76%	64%	12%	57%	55%	2%

Table 4

2006 Attribute Scores			
	Regulated States	Deregulated States	Gap
Assist with New Electro Technology	61%	36%	25%
Assistance on Being Energy Efficient	65%	40%	24%
Providing Efficiency Information	73%	51%	23%
Providing Creative Solutions	73%	53%	20%
Power Quality Assistance	79%	60%	20%
Follow-up	72%	53%	19%
Flexibility	71%	53%	18%

Regrettably the benefits derived from the ERCOT market thus far may be short lived because of plans to adopt nodal pricing sometime in the future. Nonetheless experience with the present-day ERCOT market confirms our belief that markets can be created that deliver net benefits to consumers.

B. The Best Evidence of 'What Might Have Been Under Regulation' Is What Has Actually Happened In The Regulated States

The success of any transition from regulation to true competition should be self-evident given the claims that regulation produces inefficient results and does not promote innovation, and that competition produces efficient results and promotes greater innovation. And all else equal, competition in the long run should produce more efficient and lower prices. After ten years of experience in markets such as PJM or New York, success has been far from self-evident. As documented in the previous section, customer focus has significantly waned in the Deregulated States compared to the quality of customer services that continue in the Regulated States. This is counter-intuitive. There is also no innovation at the point of sale between the market for electrical energy and end users that has captured the imagination of consumers in the same way that technological innovation has exploded after deregulation of telecommunications services. There is also circumstantial evidence that advances in smart metering and other technologies that might facilitate the marketing of new innovative services have in fact declined because it was the traditional regulated utilities that drove those advances in the past. Moreover, the disconnect between the Day Two market structure and protectionist state retail policies imposes a huge regulatory barrier to new ('third-party') market entrants who might otherwise fill that vacuum.[2]

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[2] *See* Federal Energy Regulatory Commission, *Assessment of Demand Response & Advanced Metering*, Staff Report, August 2006 at pages 125-133.

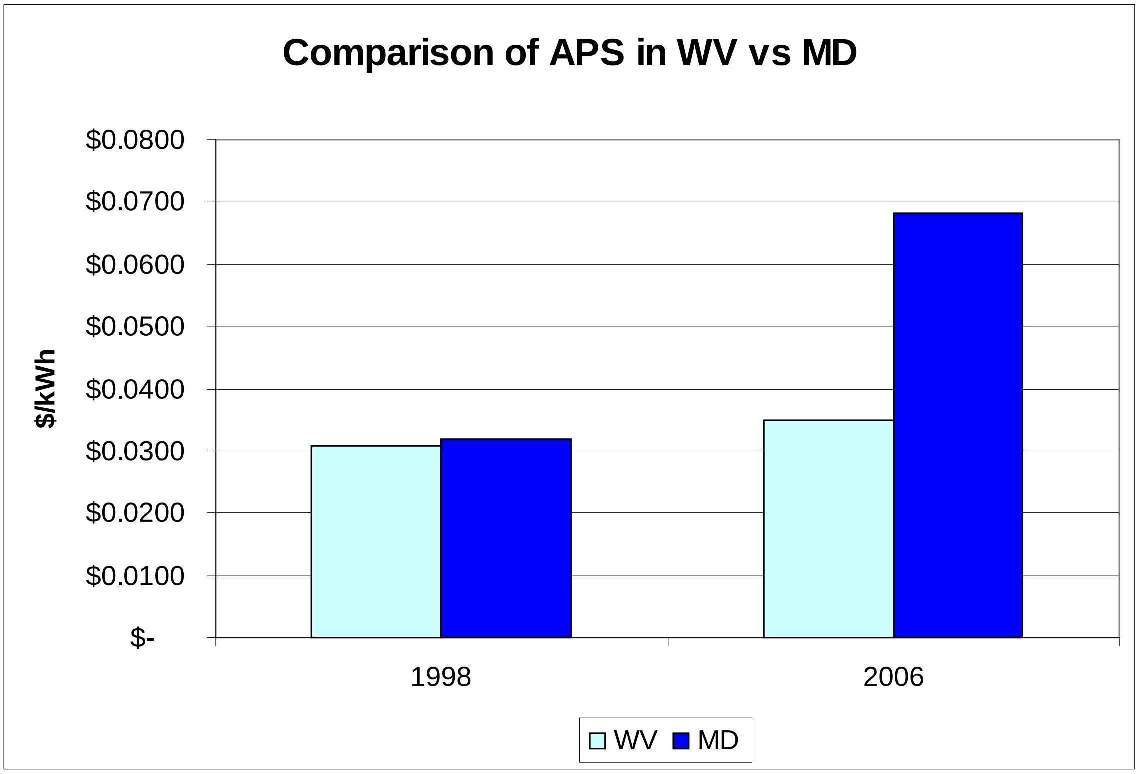
Price trends at the retail level in FERC-approved organized markets have been the subject of considerable debate. Mandated stranded cost recovery (once euphemistically called 'competitive transition charge'), legislatively imposed rate reductions, and rate freezes or caps tended to disconnect the rates or prices actually charged to many (mostly small) consumers from the wholesale prices. Part or all of the difference was securitized or allowed to accrue in a regulatory asset called a deferral account stifling any possibility that ratepayers would see a real 'price' in the transition. Some recent studies that purport to estimate the positive impact on retail rates of restructuring have resorted to far-fetched assumptions to get around the fact that the data simply does not support the claims.[3]

It is possible to surmise 'what might have been under regulation' for industrial rates and make an apples-to-apples comparison with what happened to a similarly situated load in a Deregulated State. Several utility systems overlap a Deregulated State in the footprint of a FERC-approved organized market and one or more Regulated States. The rates charged to similarly situated industrial loads in the Deregulated State can be directly compared with the rates charged under traditional rate regulation in the Regulated State. The chart on the next page shows Allegheny Energy, Inc. (APS) charges to industrial customers in both Maryland and West Virginia with an 85% load factor, in 1998 and in 2006. West Virginia consumers paid and still pay a fully bundled, state regulated cost of service rate.[4] Maryland consumers paid comparable rates in 1998, but now pay a rate based on the PJM 'market' clearing prices, irrespective of whether they continue to be served by APS or are instead served by a third-party supplier. Costs to a similarly situated industrial consumer in Maryland are now almost double what they would be for the identical consumer located across the West Virginia

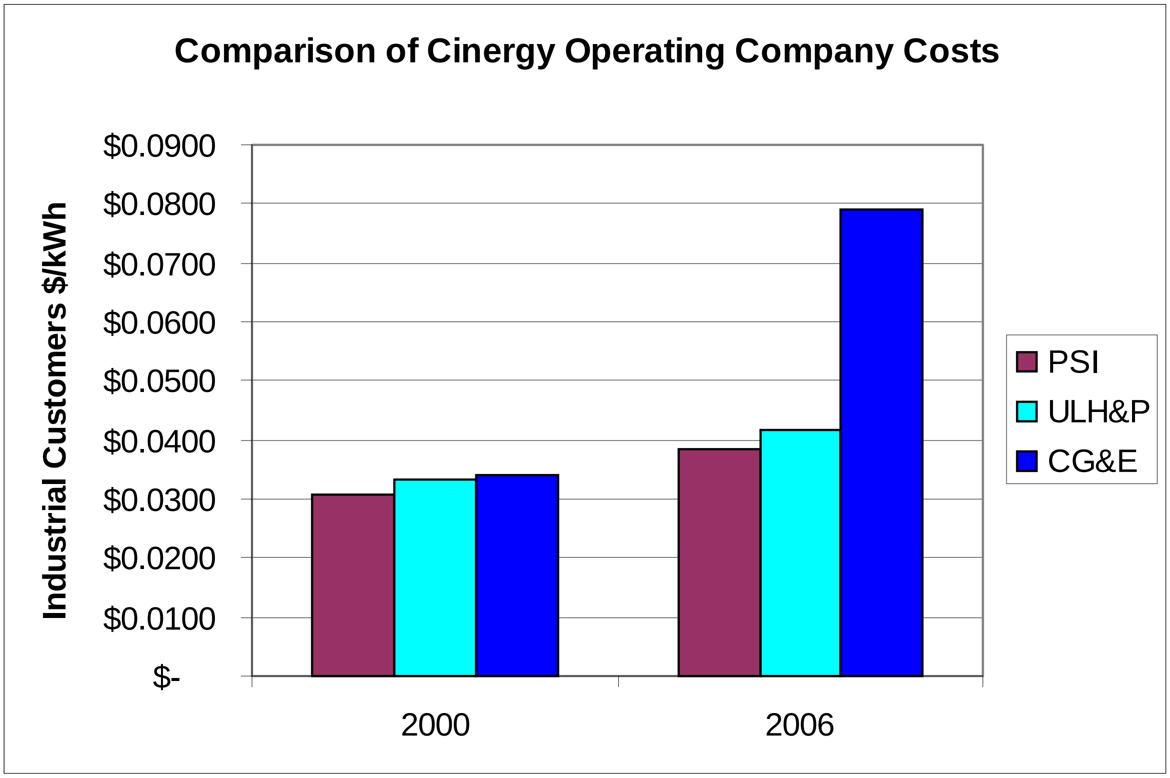
[3] *See*, for example, an excellent critique of one such study: Matthew J. Morey and Laurence D. Kirsch, 'Beyond Belief: A Critique of the Cambridge Energy Research Associates' Special Report 'Beyond the Crossroads: The Future Direction of Power Industry Restructuring',' Christensen Associates Energy Consulting, LLC, November 15, 2005.

[4] Source: Portland Cement Association, Comments On The Electric Energy Market Competition Task Force Draft Report, Docket No. AD05-17-000 ('Wholesale and Retail Electric Competition').

border. Both are served by APS, and both APS operating subsidiaries share the same generating asset base, transmission infrastructure, operating costs, corporate overheads etc.



The comparison of Cinergy operating companies in the chart on the next page shows the same effect. Cinergy Corporation owns Cincinnati Gas & Electric (Ohio) that operates in a restructured jurisdiction, and Public Service of Indiana and Union Light Heat & Power (Kentucky) both operate in regulated, cost-of-service jurisdictions. Costs have increased much more sharply in Ohio (restructured) than they have in Indiana or Kentucky (regulated). In 2000, industrial consumers with an 85% load factor in Indiana, Kentucky and Ohio would have paid $31/MWh, $33/MWh and $34/MWh respectively. In 2006, the same industrial consumers would be paying $38 per MWh in Indiana, and $42/MWh in Kentucky but $79/MWh in Ohio. All three Cinergy



companies have similar generation profiles and other cost concerns, yet Ohio consumers pay almost double what the Indiana or Kentucky consumer pays.

C. The Necessary and Essential Pre-Conditions For Real Competition

Last December ELCON issued a white paper that reaffirmed its desire for real competition, but also stated in no uncertain terms that real competition simply has not happened and is not going to happen unless at least seven necessary and essential pre-conditions are actually implemented in a closely integrated fashion. As mentioned above in section A, ELCON members that have facilities in the present-day ERCOT market report a high degree of satisfaction with the performance of that market as it is currently structured—meaning their expectations were largely met—because sufficient pre-conditions and an appropriate market design were in place when the market was launched. What were industrial consumers' expectations with respect to each of these pre-conditions in the context of the FERC-approved organized markets?

1. Price Determination By The Interaction Of Supply And Demand, Or One Hand Clapping?

An expected outcome of a competitive wholesale electricity market was that price-responsive end-use consumers would compete head-to-head with generators to establish market-clearing prices and would be paid compensation on an equivalent basis for the actual value provided to the market. Unfortunately this hasn't happen. Instead 'demand response' has become the most studied topic in the history of the industry. Maybe it has been studied to death. There has been no end to the number of reports, surveys, conferences, initiatives, collaboratives, 'national town meetings' and other efforts to jump-start this critical market function. The results have been simply a few ISO- or RTO-implemented demand-response 'programs.'

It is important to emphasize that 'programs' have been established, not markets. Consumers that elect to participate are forced into an administrative process with load-serving entities (LSEs) or ISOs and RTOs, in lieu of actual price competition with generators. While these programs certainly have some value as damage control measures for operationally flexible customers against high clearing prices, they are not a long-term substitute for the levels of demand elasticity that are necessary for truly competitive markets.

Price responsive load is essential for optimizing market and grid operating efficiencies—a cardinal benefit of competition. This cannot be done by the supply side alone in a one-sided ('one hand clapping') market because it is necessary to identify consumers' willingness to pay in the price discovery process. Price-responsive load must have access to the price-setting mechanisms of the short-term energy and ancillary services markets without restrictions that would create a bias for the bids of generators. Even minimal participation during high-priced hours can substantially reduce LMPs during those hours and reduce the cost of hedging products going forward.

Price-responsive load will usually set the clearing prices (especially during periods of scarcity pricing) and therefore induce greater demand uncertainty. This creates downward pressure on prices and increases spot market price risk for generators. Generators that face greater spot market risk will tend to increase their willingness to take a long position in the forward markets as a hedge against pricing volatility.

It is widely recognized that not all industrials want to or are capable of providing demand response because a manufacturing customer's response to real-time prices has a cost. The cost is not only the lost production, but also the impact on the cost of operations and the loss of operator focus on making a product. Many facilities that currently participate in the demand response 'programs' of FERC-approved organized markets spend an inordinate amount of time working with and around the RTO's business practices, stopping and starting operations that only perform optimally when they are run continuously, in part, to cut their losses in the energy market. Manufacturing facilities in Regulated States where rates are consistently lower are not so burdened. This turns on its head the expectation that the Day Two market design as implemented by FERC-approved ISOS and RTOs was intended to make US manufacturers more competitive in the manufacturers' markets.

If industrial consumers are expected to operate in the FERC-approved organized markets in a manner that contributes the efficiency of those markets, the result has to be lower costs than what is delivered in the Regulated States. Instead, manufacturers in PJM, NYISO and other organized markets are running their equipment in unintended ways simply to achieve a level of electricity pricing that allows them to remain only marginally viable. This frustrates any further capital investment in those locations.

Forcing customers on real-time spot prices in ill-formed markets is contributing to demand destruction after all demand reduction opportunities have been exhausted. There is growing sentiment among US manufacturers that their interests may be better served if all rates were subject to review and approval by qualified regulators.

Notwithstanding the heightened awareness of the merits of demand response, there remains a lot of passive resistance to implementing it. The conventional wisdom is that restructuring has failed and going further with ‘demand response’ may be deemed a needless pursuit when a growing number of states are grappling with putting the toothpaste back in the tube. Also, state regulators are very uncomfortable with the compensation issue: they have no problem with an unregulated generator receiving a high spot price for its power, but giving an industrial the same amount of money to un-consume goes against their grain. State regulators are also trapped by inaction because their desire to shield ratepayers from spot pricing volatility prevents them from sanctioning access by any price-responsive load.

Active resistance to demand response is pervasive within the governance structures of ISOs and RTOs where the placement of dots and commas in tariffs are argued endlessly, with a coalition of suppliers who would lose money if loads were dispatched off, rather than generation dispatch up. The solution is to get back on track with real industry restructuring or greater recognition that demand response has tremendous merit in any context: market or regulation. Demand response will constrain marginal generation costs in any context. Only the generators would not want that and it may be inevitable that they will claim new ‘missing money’ resulting from lower spot prices.

2. There Is No Such Things As ‘Missing Money’ In A Competitive Market.

A competitive wholesale electricity market was expected to stimulate new investments. There is an enormous amount of capital seeking new investment, but investment in generation has all but ceased in the organized markets, and transmission investment is not far behind. Why? The Day Two markets are not real markets – they are regulation without a rate base. Efforts to patch this huge problem with artificial centralized capacity constructs are clear indications of market failures. Perhaps worse, these constructs are not trusted by either generator owners or Wall Street. This is no trivial problem because most of the benefits of restructuring were expected to result from new long-term investments. Instead, what we got was a form of stopgap regulation that pays billions of dollars to existing generators while incenting only minimal amounts of new gas-fired generation and raising reliability concerns.

The need for an artificial capacity construct in the organized markets to compensate for the so-called ‘missing money’ is an indication of market failure. The problem should be fixed by correcting the fundamental market design and waiting until sufficient transmission infrastructure is in place to support a market, and not by attempting to treat the symptoms with administratively-determined revenue payments (i.e., payments in lieu of a market). A long-term forward market is necessary for investment to ensure resource adequacy.

Experience with the Day Two construct over the past decade, and consideration of the generation that was actually added to the grid during this period also suggest that RTO-coordinated markets alone are not sufficient to justify capital investments for any generation type other than natural gas. The ‘length’ of the market has to be at least as long as the physical lead-time necessary to encourage fuel diversity and new baseload generation. Baseload generation face enough barriers. It is bad public policy to allow arbitrary (and flawed) market designs to impose additional and unnecessary barriers to this resource.

The absence of a robust forward market prevents the financing of new generation with long-term bilateral contracts. Incumbent generators have no economic incentive to increase generating capacity because it would reduce the prices they would otherwise receive for their strategically located units.

3. Capital Cost Recovery With The ‘R’ Card

Many new players were expected to enter the competitive market, and some old, inefficient players were expected to exit. This did happen on a limited basis early on, but unfortunately many of those that bailed out were the new players. The result is the many old monopoly utilities with depreciated nuclear and coal-fired assets earning very healthy profits, while marginal gas units are barely profitable, and significant barriers to entry remain for baseload and mid-merit units.

One useful metric for the success of a truly competitive market is the ease of entry and exit. The FERC-approved organized markets are distorted in both instances. Generators in organized markets are increasingly offered the higher of market or cost to stay in business. This practice has no place in honest markets, but is condoned in organized markets because such units are typically needed for reliability-must run purposes—the so-called *RMR units.* This monopoly power is only possible because of the lack of new market entrants that would compete with the RMR units. It is one of ELCON's greatest fears that stopgap intervention in wholesale markets necessary to make generators 'whole' because the generators will otherwise bring down the grid has become a driving force that is discrediting competition as a viable alternative to regulation.

4. Customer Choice In Organized Markets - Pick One: (a) The Spot Price, Or (b) The Spot Price Plus A Premium.

A market was envisioned in which both suppliers and consumers would hedge commodity price volatility with long-term bilateral contracts. The robust, liquid forward market created with those contracts would provide investors the same or better security as a traditional utility rate base. It didn't happen. Instead, for all practical purposes, consumers that need to hedge the commodity price risk simply can't do so. Their choice is simple. Take the unbundled spot price (the highest bid clearing the market) or take a contract based on estimates of these same spot price bundled with a huge risk premium. That is not a hedge – and it certainly is not the result of a competitive market. And to add insult, industrial consumers are finding that the benefits of self-generation, perhaps the most reliable hedge in the past, are being taken away through premature repeal of PURPA based on exaggerated claims of competition.

Long-term forward markets decrease spot market prices and enhance efficiency. The organized markets have no robust forward markets because the necessary pre-conditions for workable competition are absence, such as, transmission adequacy, demand response with scarcity pricing, and other factors. Consumer opposition to scarcity pricing is justified to the extent that the bilateral contracts with suppliers are, in fact, not a true hedge but a pass-through mechanism that preserves all operational and price risk with the consumers.

5. Congestion: The New Profit Center

ELCON was an early advocate of ISOs and the separation of operation from the ownership of transmission. The hope was that the congestion costs combined with the transparent, open-access operation of the grid by an impartial 'air-traffic controller' would spur new investments. This didn't happen. First, instead of providing investment signals, the pricing mechanism tells those who own both generation and transmission where NOT to build while allowing them to continue to profit handsomely by protecting their past investments under regulation.[5] Second, the RTOs have not lived up to their promise as facilitators of regional planning and have failed to implement long-term planning that recognizes objectives such as fuel diversity, and optimal generation and transmission investment. Unfortunately, the problems are not self-correcting due to problems with RTO governance and conditions are getting worse, not better.

The nodal pricing model component of FERC's standard market design, which is adopted by all FERC-approved organized markets, is not sufficiently robust to compensate for inadequate transmission infrastructure. This fact is demonstrated by growing congestion, and therefore, growing congestion-generated revenues for generators. The nodal pricing model dispatches all generators whose bids are accepted, which in the absence of adequate transmission capacity, requires redispatch of generating units in suboptimal locations. As theory would have it, it is the consumer

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[5] In the aftermath of some well-publicized blackouts, transmission owners are making the minimum necessary transmission investments to maintain reliability but not to relieve congestion that may have only commercial impacts.

who bears the burden of congestion because of the load's proximity to any transmission constraint. Generation that was sited in suboptimal locations is exempt from the economic consequences of its siting decision. This makes a mockery of the 'price signal' arguments of nodal pricing.

Inadequate transmission infrastructure stifles liquidity at congested nodes, which tends to exacerbate and preserve local market power (and preserve an under built infrastructure), and increase the potential frequency and severity of scarcity pricing—and thus opposition to scarcity pricing.

6. The Perils Of Joint Ownership of Generation & Transmission

Greater competition was assumed to mitigate the potential to exercise market power. This might have been accomplished if the five previous pre-conditions had actually been implemented. But this has not happened, and market power is now arguably a bigger problem, as the merchant generation sector consolidates before the structural features necessary to mitigate market power are in place. Market monitors and antitrust authorities cannot fill this void for a number of reasons.

The price signals promised under the nodal pricing model were supposed to signal and facilitate new investments in generation and transmission infrastructure that enhance market and grid efficiencies. This promise is greatly undermined by the market power of utility holding companies that own both generation and transmission assets.

ISOs and RTOs were intended as 'platforms' for competition by severing the operation of transmission from the ownership of transmission and generation. This was intended to mitigate the market power of joint ownership, but that might have been successful only if the transmission system was adequately built—and it was not.

ISO/RTO functional separation does nothing to promote new investments in infrastructure, and in fact, coupled with the nodal pricing model, provides powerful economic signals to not build. Incumbent generation owners have no economic incentive to expand generation capacity that would reduce the price offered to their existing asset fleet. If the generation owner has a corporate affiliate that owns transmission, that affiliate will not develop new transmission infrastructure that will expose its generation or marketing affiliates to greater competition.

The Market Monitoring Units (MMUs) were intended to be the first line of defense that protects consumers from the exercise of market power. But as practiced in some RTOs and ISOs, market monitoring has tended instead to being a palliative for defending imperfections of nodal pricing.

It should be clear from the evidence of the decade-long restructuring experiment that the role of the MMU expands with market imperfections, and contracts as markets mature to workable competition. It is also important that the MMU be agnostic with respect to how the market is designed and focus more how the market actually performs. A market monitor who is an advocate of nodal pricing may not be as objective or aggressive in uncovering fundamental flaws in market operation, or seeking remediation of those flaws.

Recent judicial authority adds urgency to the Commission's own observations of market performance. We interpret the recent 9th Circuit decision in PUD of Snohomish v. FERC as extending way beyond the specific context of the western markets crisis of 2000-2001. FERC must assure that markets remain competitive to support market-based rate (MBR) authority both under that decision and under the DC Circuit precedent providing that market-based rates are just and reasonable if and only if there are competitive markets and an absence of market power.

7. Scarcity Pricing Only For The Willing

Competitive markets in electricity were envisioned with the look and feel of other commodity markets. There could not be real competition if scarcity pricing was eliminated from the market.

Scarcity pricing is common to almost all competitive markets for signaling imbalances in supply and demand, for sending short-term signals to consumers to adjust consumption behavior, and for sending signals to producers of the price the market is willing to pay for the next unit of supply. That short-term price signals may approach the long-term marginal cost of production is acceptable to economists but not politicians. In electricity markets, it should not be controversial even to politicians as long as other competitive pre-conditions co-exist and <u>no one is forced into the spot market</u>.

Opposition to the removal of price caps and bid mitigation measures in the organized markets is probably a tacit, collective fear that the pre-conditions necessary for workably competitive wholesale electricity markets (enumerated above) may be unachievable or impractical. Opposition is also inevitable from utility holding companies with unregulated affiliates that financially benefit from the flawed markets, and who rightfully fear any attempt to fix the markets and make them truly competitive.

The ultimate purpose of ELCON's December 2006 white paper is to encourage and accelerate the debate on these fears because only after all the above conditions necessary for truly competitive markets have actually been implemented, is it feasible to consider relaxing wholesale price caps and bid mitigation measures and price floors. This recognizes the critical need for sufficient new investments in transmission and generation to exert downward pressure on prices. <u>The single worse thing that could happen is partial or piece-meal implementation of some of these conditions (e.g., scarcity pricing) that would only increase the economic harm facing consumers</u>.

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Recommendations

Going forward, what should FERC do? ELCON offers the following four recommendations:

1. <u>FERC should acknowledge that the Day Two construct is not working for the benefit of end-use consumers as required by the Federal Power Act</u>. LMP is not robust enough to compensate for inadequate infrastructure should never have been implemented without additional transmission and the elimination of major load pockets. LMP will not work unless enough infrastructure is in place to sufficiently mitigate the consequences of joint generation-transmission ownership of incumbent utility holding companies. Price signals are clearly not stimulating, and are probably discouraging, new infrastructure investment. Federal and state regulators do not share the same vision for the industry, which accounts for lack of demand response or agreement on long-term resource adequacy. In short, the Day Two market construct has created more profound problems than the move to greater competition was intended to solve.

2. <u>FERC should initiate an inquiry into whether today's RTO platform, with LMP, can be made a viable market model.</u> Are the necessary preconditions achievable and capable of delivering net benefits to end-use consumers? Can this platform address the problems such as infra-marginal revenues, barriers to entry for new baseload and mid-merit generation, siting problems for transmission, etc. The outcome of this inquiry should be a new road map for either reforming the RTO/LMP framework <u>or</u> considering a return to regulation.

3. <u>FERC should acknowledge the magnitude of this problem and recognize that simple technical fixes or additional regulatory intervention will not correct the inherent problems.</u> FERC must be ready to substantially change the basic underlying structure and implement tariffs that ensure that wholesale rates that end users ultimately pay are just and reasonable. Additional patches will not fix the problems.

4. <u>If conditions necessary to implement LMP cannot be achieved, the policy debate must shift to what form of regulation is appropriate for jurisdictional utilities: state, federal or a combination of the two.</u> If the Commission opts to 'stay the course,' the default option is continued consumer exploitation, no end-user focus and rates based

on marginal bids further inflated by unmitigated congestion. Even worse, states will continue to rebel and take actions that at best will bring only minimal benefits. Such actions result in neither good public policy nor adequate consumer benefits. This is a major challenge.

Respectfully submitted,

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