TIME FOR A DAY 1.5 MARKET: A PROPOSAL TO REFORM RTO-RUN CENTRALIZED WHOLESALE ELECTRICITY MARKETS

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Synopsis: This article presents a proposal to reform the current "Day-Two" electricity markets operated by certain regional transmission organizations (RTOs). The proposed reforms are intended to restructure these RTOs to maintain their demonstrated consumer and economic benefits, which we think arise primarily from RTOs' "Day-One" transmission-related functions (including the elimination of utility-by-utility transmission rate "pancaking" in favor of a region-wide rate structure that better supports a regional power supply market). At the same time, our proposed reforms seek to deemphasize the role of RTO-run centralized power supply markets and provide support for a stronger bilateral power supply contracting regime. Since eliminating the centralized dispatch and financial transmission rights that RTOs currently employ could create significant transitional difficulties for many load-serving entities (LSEs), however, this proposal incorporates features of both the Day-One and Day-Two models. Accordingly, we have dubbed our proposal the "Day 1.5" RTO model.

The central goals of our proposal are to moderate and reduce volatility in electric power prices and to reduce the opportunities for gaming available in the current RTO-run spot markets, while preserving the acknowledged regional transmission benefits that RTOs provide and promoting a more stable electricity supply environment that might better support development of new generation and demand response resources. We hope to accomplish these goals without the need for locational capacity markets, elimination of price caps on RTO-run short-term energy market prices, or other such mechanisms that we fear will further increase prices to consumers without concomitant benefits.

Consumers are already very likely to face increased electricity prices in the coming years, given increasing infrastructure requirements, rising fuel and construction costs, and the need to comply with future carbon regulation. Our proposal is an attempt to ensure that consumers get fair value for their dollar in the form of needed new infrastructure and reliable service.

This article is divided into five sections, including this synopsis. The second section provides an introduction to the issues, including a review of the major changes in wholesale electricity markets over the past fifteen years and a description of the basic features of RTOs. The third section considers the

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structural requirements for competitive wholesale power markets and examines whether competition has in fact been achieved in RTO-run markets, reviewing the results of a recent set of studies commissioned by the American Public Power Association (APPA) examining various aspects of these markets. The fourth section summarizes the Federal Energy Regulatory Commission's (FERC) statutory responsibility to ensure just and reasonable wholesale electric rates. The fifth and final section presents possible features of a Day 1.5 RTO market model.

I. INTRODUCTION

Wholesale electricity markets have changed fundamentally since the passage of the Energy Policy Act of 1992.[1] The FERC has moved well beyond ensuring non-discriminatory open access transmission service by FERC-regulated "public utilities" under sections 205 and 206 of the Federal Power Act (FPA).[2] Since the FERC's issuance of Order No. 2000,[3] it has fostered

1. Energy Policy Act of 1992, Pub. L. No. 102-486, 106 Stat. 2776 (1992).
2. 16 U.S.C. §§ 825d and 825e (2006).

implementation of centralized wholesale electric markets developed and operated by RTOs, employing widespread use of market-based rate authority and a complex set of market rules.

During this same period, many states located in RTOs' geographic "footprints" implemented "retail access" or "retail competition" programs, intended to provide their retail electric consumers with a choice of power providers.[4] In most of these states, as part of the transition to retail access, the incumbent investor-owned utilities (IOUs) sold off their generating plants to third parties (in many cases, to their unregulated affiliates). These third parties now sell their power at wholesale under FERC-granted market-based rate authority, subject only to RTO "market mitigation" rules.[5] In these states, traditional retail cost-of-service rate regulation of vertically-integrated IOUs by state public utility commissions (PUCs) has accordingly been replaced by the direct pass-through in retail rates of wholesale electric prices, which are often set in RTO-run markets. State PUCs in these states now have little ability to regulate the power supply portion of retail electric rates, as they previously did under traditional "bundled" retail rate regulation.

These federal and state policy changes resulted from increasing dissatisfaction with the performance of electric utilities under traditional cost-of-service regulation beginning in the 1970s and going through the 1980s to the 1990s. Such rate regulation was thought to foster a "pass-through mentality,"[6] under which IOUs had few incentives to keep their costs down, and substantial economic incentives to increase their rate bases (and thus their return on and of invested capital). The rate increases that customers of some electric utilities experienced due to very substantial cost overruns incurred to build a number of controversial nuclear plants during the 1970s and 1980s contributed to this perception.[7] The changes in wholesale and retail power supply markets were

3. Final Rulemaking, *Regional Transmission Organizations, Order No. 2000*, 65 Fed. Reg. 809 (1999) (to be codified at 18 C.F.R. pt. 35), *order on reh'g*, *Regional Transmission Organizations*, *Order No. 2000-A*, 65 Fed. Reg. 12,088 (2000) (to be codified at 18 C.F.R. pt. 35), *aff'd sub nom*; Public. Util. Dist. No. 1 of Snohomish v. FERC, 272 F.3d 607 (D.C. Cir. 2001) [hereinafter *Order No. 2000*].

4. For a number of years, the Virginia State Corporation Commission prepared an annual report to the Virginia General Assembly discussing the state of retail access both in Virginia and in other retail access states. The last such report, prepared in 2006, noted that sixteen states and the District of Columbia had fully implemented retail access, Nevada and Oregon allowed retail access for larger customers only, six states had indefinitely postponed or repealed their retail access regimes, twenty-six states were not considering retail access at that time, and no state had passed restructuring legislation since June 2000, when the Western power crisis began. KENNETH ROSE & KARL MEEUSEN, 2006 PERFORMANCE REVIEW OF ELECTRIC POWER MARKETS 12-13 (2006), http://www.scc.virginia.gov/comm/reports/2006_rose_1.pdf [hereinafter ROSE & MEEUSEN].

5. APPA, CONSUMERS IN PERIL, WHY RTO-RUN ELECTRICITY MARKETS FAIL TO PRODUCE JUST AND REASONABLE ELECTRIC RATES 1 (2008) http://www.appanet.org/files/PDFs/ConsumersinPeril.pdf [hereinafter CONSUMERS IN PERIL].

6. ELECTRIC ENERGY MARKET COMPETITION TASK FORCE, REPORT TO CONGRESS ON COMPETITION IN WHOLESALE AND RETAIL MARKETS FOR ELECTRIC ENERGY 19 (2007) http://www.ferc.gov/legal/fed-sta/ene-pol-act/epact-final-rpt.pdf [hereinafter TASK FORCE REPORT].

7. The issues and concerns with traditional cost-of-service regulation that led to electric industry restructuring are discussed in the April 2007 *Report To Congress On Competition In Wholesale And Retail Markets For Electric Energy*, which was prepared by a federal governmental interagency Electric Energy Market Competition Task Force, as required by section 1815 of the Energy Policy Act of 1992. TASK FORCE REPORT, supra note 6, at 44-47.

therefore predicated on the assumption that the combination of these new centralized RTO-run wholesale markets, and retail direct access, would promote "competition." It was thought that increased competition would spur efficiencies and innovation, ensure adequate generation supplies, and, most importantly, lower rates to consumers.

However, the results of a number of recent studies of RTO-run wholesale markets (discussed in Section IV.C.), as well as the real-world experience of load-side and consumer interests,[8] has called these assumed outcomes into question. Restructured wholesale markets are producing both higher prices and higher profits than one would expect in a competitive market. Resulting retail prices exceed those prevailing in regions that have not restructured, but that instead retained traditional retail cost-of-service regulation and eschewed the formation of RTOs. Long-term adequacy of generation resources is also a substantial concern in RTO regions.

Given these developments, the views of RTO-market proponents about the perceived failures of past cost-of-service regulation need to be balanced with opposing views about the substantial shortcomings of electricity restructuring in general and RTO-run wholesale electric markets in particular. It is those on the receiving end of these RTO market realities – end-use consumers and the organizations that represent them, the LSEs responsible for meeting their needs, and increasingly the state regulators who see most clearly the problems retail consumers face – who have expressed the most concerns about these markets. In contrast, it is the RTOs that operate these markets, the federal regulators that encouraged their formation, and the generators that profit from their operation that make the strongest claims consumers are benefiting from them. This disconnect in itself should prompt policymakers to examine more closely what interests are in fact benefiting from the operation of these markets and how they are doing so.

We hasten to add that RTOs provide real benefits to consumers. RTOs provide independent and non-discriminatory transmission service under open access transmission tariffs (OATTs), charging regional transmission rates instead of individual system-by-system "pancaked" transmission rates.[9] They maintain reliable transmission service through their "wide-area [view]"[10] of moment-to-moment system operations.[11] They lead regional collaborative transmission planning processes. Such RTO functions undoubtedly benefit consumers. Yet the FERC's policies have increasingly lost sight of these core transmission-oriented RTO functions, as implementation of centralized markets for energy, ancillary services, and generation capacity have taken center stage. It is the RTO-run centralized wholesale markets and their performance that are the primary focus of this article.

8. *See, e.g.,* note 188, *infra*.
9. CONSUMERS IN PERIL, *supra* note 5, at 12.
10. *Id.* at vii.
11. *Id.*

II. FEATURES OF CENTRALIZED RTO-RUN WHOLESALE ELECTRICITY MARKETS

A. *Description of RTO Day-Two Markets*

RTO-run centralized wholesale markets for electric energy, generation capacity and ancillary services, while generally operated without traditional cost-of-service regulation, are nonetheless heavily regulated, requiring numerous market rules, administrative bureaucracies, and extensive complex software.[12] There are currently six FERC-regulated Independent System Operators (ISOs) that operate as RTOs:[13] ISO New England (ISO NE), the New York ISO (NY ISO), the PJM Interconnection, LLC (PJM, which covers the Mid-Atlantic states and some parts of the Midwest), the Midwest ISO (MISO, which covers other parts of the Midwest), the California ISO (CAISO), and the Southwest Power Pool (SPP), which covers parts of Texas, Louisiana, Arkansas, Missouri, Kansas and Oklahoma.[14] With the exception of the SPP,[15] these RTOs currently or will soon operate, centralized day-ahead (DA) and real-time (RT) spot markets for electric energy, as well as markets for certain ancillary services needed to support open access transmission service.[16]

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12. For a more detailed description of RTO market operations, *see generally* GARY NEWELL & RANSOM DAVIS, UNDERSTANDING ELECTRICITY MARKETS: AN EXAMINATION OF HOW ELECTRICITY MARKETS WORK – AND HOW THEY DON'T (APPA) (2006), *available at* http://www.appanet.org/aboutpublic/index.cfm?ItemNumber=17766 [hereinafter NEWELL & DAVIS].

13. For simplicity's sake, these organizations will be referred to in this article as "RTOs." An RTO is a regional transmission entity that meets certain criteria and performs specific functions which the Commission set out in *Order No. 2000*, *supra* note 3. The criteria are: independence, appropriate geographic scope, operational authority for all transmission facilities under the RTO's control, and authority to ensure short-term reliability. *Id.* at p. 30,991. The minimum RTO functions are: tariff administration and design, congestion management, development and implementation of loop flow and parallel path procedures, provider of last resort for ancillary services, operation of an Open Access Same-time Information System (OASIS), independent calculation of total transmission capability and available transmission capability, market monitoring, transmission planning and expansion, and interregional coordination. *Id.* at p. 30,993-30,994. While CAISO has not sought official recognition by the Commission as an RTO, the authors believe that CAISO is effectively operating as one.

14. The Electric Reliability Council of Texas (ERCOT) is also an ISO, but since ERCOT does not operate in interstate commerce, it is regulated by the Texas Public Utility Commission and not the FERC. ERCOT, MARKET RULES, http://www.ercot.com/mktrules/ (last visited Sept. 22, 2008).

15. SPP has not to date proposed to implement a full array of markets, but does operate an energy imbalance market. SPP is conducting a cost-benefit study of a day-ahead market with centralized unit commitment, expected to be completed by October 2008, with implementation of market changes within two to three years afterwards. SPP, REQUEST FOR PROPOSAL: COST BENEFIT STUDY FOR FUTURE MARKET DESIGN (2008) http://www.spp.org/publications/CBTF_Future%20Market_RFP_Jan252008_final.pdf; *see also Electric Mkt. Reform Initiative (EMRI) Task 2 Analysis of Operational & Admin. Cost of RTOs*, REPORT FOR THE APPA, (GDS Assoc., Inc., Marietta, Ga.), Feb. 5, 2007 http://appanet.org/files/PDFs/AnalysisCostofRTOs020507GDS.pdf [hereinafter APPA REPORT].

16. CAISO's Market Redesign and Technology Upgrade (MRTU) proposal has been approved by the FERC, and although not expected to be in place until 2009, once implemented, will provide CAISO a Day-Two market. MRTU will include locational marginal pricing, congestion revenue rights and a day-ahead market, all features of current Day-Two RTOs. *See generally* CAISO, MARKET REDESIGN & TECHNOLOGY UPGRADE (MRTU), http://www.caiso.com/docs/2001/12/21/2001122108490719681.html (last visited Sept. 22, 2008); Memrorandum from CAISO Staff to CAISO Board regarding MRTU Budget dated August 29, 2008, at 3 (recommending a January 31, 2009 MRTU start date), http://www.caiso.com/2036/2036b43d46d118.pdf (last visited October 12, 2008) .

The prices for electric power in these centralized markets are set at specified intervals (every hour or a given time interval within an hour) based on the offers to sell power submitted by generation owners, operators and marketers to the RTO.[17] These offers need not reflect the sellers' actual costs of generating power (average, marginal, or otherwise), as the FERC would have required in the past under a traditional cost-of-service ratemaking regime. Rather, the sellers set their own bids to sell power, unless the prices they propose trigger pre-set "market mitigation" thresholds set by the RTO.

Each RTO has a Market Monitoring Unit (market monitor or MMU) that develops mitigation rules intended to keep bidders from exercising generation market power through their bids.[18] These rules are complex, and themselves often contain exceptions.[19] Moreover, much of the work done by MMUs is confidential; they do not disclose information regarding their oversight of market participants' activities. Actions they may take regarding the market behavior of a particular generator is generally never made public unless the generator discloses the action, or eventual action is taken against the generator by the FERC, and the action is then made public. While market monitors are supposed to be independent of the RTOs they monitor, there have been questions about whether they are indeed sufficiently independent, and whether their activities should be taken on by the FERC itself.[20] The much publicized case regarding PJM's MMU, which centered on allegations that PJM had interfered with the market monitor's independence in a number of instances, only heightened such concerns, although it eventually resulted in a settlement agreed to by PJM, PJM's market monitor, and the PJM market participants.[21]

The RTO takes all power supply offers for a particular upcoming time interval in ascending price order, stopping with the last offer needed to meet the power needs of loads during that time interval. All sellers in that time interval, regardless of the amount of their own price offers, are paid the price based on the last and highest offer the RTO accepts to supply power to meet its regional demand - known as the "market clearing price."[22] This market design is known

17. NEWELL & DAVIS, *supra* note 12. For this reason, such RTO markets are often called "bid-based" markets.

18. CONSUMERS IN PERIL, *supra* note 5, at 32.

19. For example, exemptions from mitigation were granted to certain generators in PJM. The Maryland Public Service Commission (MPSC) asserted in a complaint filed with the FERC against PJM in January, 2008, that as a result of these exemptions to its market monitoring rules, "a significant [share] of the generation resources" in the PJM footprint avoids mitigation even though they exercise market power, and that these exemptions had "added $87.5 million to Maryland's 2006 real-time energy [related] charges." MPSC v. PJM Interconnection, LLC, 123 F.E.R.C. ¶ 61,169 at P 8 (2008). The FERC issued an order on May 16, 2008, concluding that the existing mitigation exemptions had become unjust and unreasonable and establishing a proceeding to examine whether PJM's existing market power screen has become unjust and unreasonable, but it denied the MPSC's request for retroactive relief. *Id.*

20. *See e.g.*, Robert J. Michaels, *Watching the Watchers,* FORTNIGHTLY MAGAZINE, July 15, 2003, http://www.pur.com/pubs/4224.cfm ("Calling an RTO or [market monitoring institution] independent does not make it so. The closer to an RTO (and the farther from [the] FERC) a monitor is, the more questionable its independence.").

21. *Allegheny Electric Coop., Inc. v. PJM Interconnection, LLC,* 120 F.E.R.C. ¶61,254 (2007) (order ruling on tariff issues and establishing settlement proceedings), 122 F.E.R.C. ¶ 61,257 (2008) (order accepting uncontested settlement).

22. NEWELL & DAVIS, *supra* note 12.

as a "single price auction"[23] market, and such markets are often called "Day-Two" markets.[24]

Another central element of RTO-operated energy markets is "locational marginal pricing"[25] (LMP), under which electricity is selected by the RTO under its market rules at prices that vary by location within the RTO's footprint. LMP reflects the differences in the costs of delivering electric power to different parts of the transmission grid due to transmission constraints on the system (often called "congestion").[26] Prices for power in the RTO's DA and RT markets vary by location in the RTO's footprint during intervals when transmission congestion (demand for use of specific transmission facilities that exceeds those facilities' physical capacity to move power) makes it impossible for electricity to reach every part of the RTO's system at the lowest overall economically efficient cost.[27] If a customer is located in a portion of the transmission system affected by such a facilities limitation (a "constrained zone"), the price the customer pays for power in the RTO's markets reflects the offer submitted to the RTO by the generator that is actually able to deliver electricity to the customer, even if there are generators offering lower prices elsewhere in the RTO's footprint.[28] The difference between the lower price and that charged in the constrained zone is referred to as the "congestion charge," and it is added to the transmission service portion of an RTO transmission customer's rates.[29]

RTOs provide their transmission customers with an opportunity to limit the adverse financial impact of congestion charges by offering them "financial transmission rights (FTR),"[30] which generally give holders a right to receive a share of the congestion revenues paid by transmission customers.[31] Typically, RTOs allocate some portion of these FTRs to transmission customers based on the amount and location of the generating resources that each load-serving transmission customer has declared it will use to serve its retail loads.[32] RTOs

23. *Id*. at Supplemental Information, *How RTO Market-Clearing Prices Are Determined*.

24. For an example of the use of this term by the FERC, *see, e.g.*, F.E.R.C. News Release, Final Rule Revises PURPA Mandatory Purchase Obligation for Electric Utilities as Mandated by the Energy Policy Act, Docket No. RM06-10-000 (Oct. 19, 2006) (http://www.ferc.gov/news/news-releases/2006/2006-4/10-19-06-E-2.asp#skipnavsub).

25. NEWELL & DAVIS, *supra* note 12, at *RTO Market Design Today*.

26. *Id.*

27. *Id.*

28. *Id.*; *see also*, Seth Blumsack, *Measuring the Benefits and Costs of Regional Electric Grid integration,* 28 ENERGY L.J. 147, 174-175 (2007) [hereinafter Blumsack].

29. NEWELL & DAVIS, *supra* note 12, at *RTO Market Design Today*; Blumsack, *supra* note 28.

30. FIONA WOOLF, GLOBAL TRANSMISSION EXPANSION: RECIPES FOR SUCCESS 175 (PennWell Books 2002).

31. Holding such FTRs, however, is not without financial risks to the receiving transmission customers. In most cases, the FTRs that RTOs provide are called "obligation" FTRs, because they can also require the holder to pay dollars to the RTO if the price differential between the FTR's designated source and sink reverses. When this happens, the FTR is said to have "gone negative." In some cases, RTOs have made available "option" FTRs; these do not require the holder to pay out dollars if the price differentials reverse, but fewer of them can be issued, since counterflow FTRs cannot be employed, meaning there will be fewer total FTRs issued. *Id.* at 172-175.

32. NEWELL & DAVIS, *supra* note 12, at *RTO Market Design Today*. In some RTOs, such customers are given "Auction Revenue Rights" (ARRs), which they can then either convert to FTRs or use to receive a portion of the revenues from a subsequent auction of FTRs. PJM, WORKSHOP ON PJM ARR & FTR MARKET

also hold FTR auctions and facilitate the secondary purchase and sale of FTRs among customers.

In addition to the energy markets, RTOs also administer markets for the sale and purchase of generation capacity (the ability to produce electric energy on an instantaneous basis as, and when needed, based on physical or contractual access to electric generation facilities).[33] LSEs with traditional service obligations to retail customers have historically maintained an adequate amount of capacity to meet their respective contributions to the region's projected peak loads plus a reserve margin, either through ownership of electric generation facilities or contracts with suppliers. Moreover, prior to the formation of RTOs, there were in certain regions agreements among utilities to meet capacity obligations to each other. Such obligations were common features of power pool agreements, for example.[34] These pool-type supply arrangements in RTO regions, however, were generally superseded by RTO-run centralized markets. Eventually, concerns regarding the adequacy of generation resources to meet demand led three RTOs (ISO NE, PJM, and the NY ISO) serving in regions where most states have moved to retail access to implement locational capacity markets.[35] In these markets, existing and new generators (as well as demand response resources) with resources in designated sub-regions of the RTOs' footprints submit offers to receive revenues (in addition to those they receive from centralized DA, RT and ancillary services market transactions) from the RTO and its load-serving customers. In exchange they assure the RTO that their generation facilities (or load reduction) can be called on to supply power or to reduce the demand for power. The locational capacity markets that PJM and ISO-NE operate obligate sellers to supply such capacity for a number of years into the future, and hence are often called "forward capacity markets."[36] The PJM and NY ISO locational capacity markets are discussed further in Section IV.C.2.

2008/2009, http://www.pjm.com/markets/ftr/downloads/2008-annual-ftr-auction.pdf (last visited Sept. 22, 2008).

33. NEWELL & DAVIS, *supra*, note 12, at *RTO Market Design Today*.

34. *See*, *e.g.*, Municipalities of Groton v. FERC, 587 F.2d 1296 (D.C. Cir. 1978). Member utilities generally met such capacity obligations through self-generation or wholesale purchases of firm capacity. The generation resources of all member utilities were then "pooled" and dispatched centrally on the basis of cost, using a "split-the-savings" model to compensate the selling utility. For a description of how generators in PJM participated in its power pool prior to the advent of RTO markets, including a discussion of the split-the-savings methodology, *see generally* Letter from Joel Klein, Assistant Attorney General, Department of Justice Antitrust Division, to Gary Kaplan, Reed Smith Shaw & McClay, LLP (Jan. 30, 1998), *available at* http://www.usdoj.gov/atr/public/busreview/1337.pdf.

35. *PJM Interconnection, LLC*, 117 F.E.R.C. ¶ 61,331 (2006) (implementing PJM's Reliability Pricing Model (RPM)), *order on reh'g*, 119 F.E.R.C. ¶ 61,318 (2007), *reh'g denied*, 121 F.E.R.C. ¶ 61,173 (2007); *Devon Power LLC*, 115 F.E.R.C. ¶ 61,340 (2006) (approving ISO NE's Forward Capacity Market (FCM)), *on reh'g,* 117 F.E.R.C. ¶ 61,133 (2006); *ISO New England, Inc*., 117 F.E.R.C. ¶ 61,132 (2006); *ISO New England, Inc*., 119 F.E.R.C. ¶ 61,044 (2007), *aff'd in relevant part sub nom*; Maine Pub. Util. Comm'n v. FERC, 520 F.3d 464 (D.C. Cir. 2008); *New York Indep. System Operator, Inc.*, 103 F.E.R.C. ¶ 61,201 (Demand Curve Order), *reh'g denied*, 105 F.E.R.C. ¶ 61,108 (2003) (approving NY ISO Installed Capacity (ICAP) market), *aff'd sub nom.*, Electricity Consumers Res. Council v. FERC, 407 F.3d 1232 (D.C. Cir. 2005).

36. 119 F.E.R.C. ¶ 62,857 at P 138 (2007).

B. Concerns with RTO Day-Two Markets

The centralized markets that form the core of RTO energy markets can create financial incentives for generators to withhold capacity (to create artificial shortages that increase prices)[37] and to refrain from building otherwise-needed new generation capacity (which could reduce prevailing market prices, thus reducing profits). Such incentives, along with complex market rules and the FERC's primary reliance on competitive forces to assure adequate generation and transmission infrastructure, can in extreme cases jeopardize reliable service to retail electric customers, as witnessed by the load shedding that customers experienced in California during the 2000-2001 energy crisis.[38]

These economic disincentives to development of adequate infrastructure are in contrast to the economic theory on which LMP is based – that the higher power supply prices and transmission congestion charges levied when congestion occurs on the transmission system will give market participants an incentive to develop and pay for construction of new generation and

37. Such withholding can take two forms: physical withholding (the outright failure to bid in resources that are in fact available to run in the relevant time period) and economic withholding (the bidding in of resources at such a high price that in fact they are not available to the market). For examples of the former, *see, e.g.*, F.E.R.C., News Release, Commission Approves $13.8 Million Settlement With Reliant Energy Over Physical Withholding in California Power Exchange Market, Docket No. PA02-2-001 (Jan. 31, 2003) (http://www.ferc.gov/news/news-releases/2003/2003-1/01-31-03-reliant.pdf); Transcript of Record, *Fact-Finding Investigation into Possible Manipulation of Electric and Natural Gas Prices*, Docket No. PA02-2-001 (2000) (http://www.ferc.gov/news/news-releases/2003/2003-1/Transcripts-Reliant.pdf); *Enron Power Marketing, Inc*., 119 F.E.R.C. ¶ 63,013 (2007) Ex. No. SNO-58, Ex. No. SNO-525 (testimony of Robert McCullough discussing Enron's gaming strategies intended to create artificial scarcity conditions in the CAISO market to enhance profits and transcript of conversation between representatives of Enron and Las Vegas Cogen regarding a pretextual shut-down of a Las Vegas Cogen generating unit at the request of Enron). For an example of the latter, *see generally In re Edison Mission*, *Order Approving Stipulation and Consent Agreement*, 123 F.E.R.C. ¶ 61,170 (2008) (approving a settlement between the Commission's Office of Enforcement (OE) and Edison Mission regarding Edison Mission's misleading of OE Staff regarding its use of a "high offer" strategy in the PJM DA market that PJM's MMU concluded made the resources so bid effectively unavailable to the market).

38. Even Dr. Paul Joskow, a strong proponent of deregulation of electric generation, has now acknowledged that withholding by generators played a significant part in the California energy crisis. Paul Joskow, *Lessons Learned from Electricity Market Liberalization*, at 9-10, Dec. 8, 2007, http://econ-www.mit.edu/files/2093:

> It is true that California's wholesale market would have been stressed due to tight capacity during the second half of 2000 even if there had been no market power problems. Demand was unusually high throughout the Western Interconnection, natural gas prices and NOx permit prices rose significantly. However, even after taking account of these factors it is hard to explain what happened during the second half of 2000 only as the result of the interplay of supply and demand in a competitive market. The 'shortage' of generating capacity may perhaps be explained by older plants breaking down and by their owners' reluctance to supply when it became unclear about January 2001 whether or not they would be paid. However, there is also abundant evidence that some suppliers exploited opportunities to engage in strategic behavior to jack up market prices. At least in the summer of 2000, some generators were taking advantage of a tight supply situation to exercise market power (Borenstein, Bushnell and Wolak (2002), Joskow and Kahn (2002)). The tapes of the conversations of traders for Enron and other companies that subsequently were released make it clear that they saw and took advantage of opportunities to withhold supplies and increase market prices during the crisis.

Id.

transmission facilities, to eliminate such congestion costs in the future.[39] However, there is little evidence that such LMP-based "pricing signals" have in fact led to construction of substantial new generation or transmission facilities.[40]

Higher prices resulting from LMP differentials have increased electricity prices to LSEs that, along with other RTO transmission customers, have had difficulties obtaining FTRs of sufficient coverage and duration to hedge fully deliveries of power from their own electric generation sources to their loads.[41]

39. In its original November 25, 1997 order accepting PJM's filing to restructure the PJM Pool to implement LMP, the FERC found:

> We believe that the LMP model will promote efficient trading and be compatible with competitive market mechanisms. In this regard, we find that the LMP approach will reflect the opportunity costs of using congested transmission paths, encourage efficient use of the transmission system, and facilitate the development of competitive electricity markets. By pricing the use of constrained transmission capacity on the basis of opportunity costs, the proposal will also send price signals that are likely to encourage efficient location of new generating resources, dispatch of new and existing generating resources, and expansion of the transmission system.

Id. *Pennsylvania-New Jersey-Maryland Interconnection*, 81 F.E.R.C. ¶ 61,257, at p. 62,253 (1997), *on reh'g,* 92 F.E.R.C. ¶ 61,282 (2000), *vacated and remanded on other grounds,* Atlantic City Elec. Co., v. FERC, 295 F.3d 1 (D.C. Cir. 2002), *on remand*, 101 F.E.R.C. ¶ 61,138 (2002), *on reh'g,* 103 F.E.R.C. ¶ 61,170 (2003), *on petitioners' petition to enforce mandate,* Atlantic City Elec. Co., v. FERC, 329 F.3d 856 (D.C. Cir. 2003).

40. EZERA HAUSMAN ET AL., SYNAPSE ENERGY ECON., INC., LMP ELECTRICITY MARKETS: MARKET OPERATIONS, MARKET POWER, & VALUE FOR CONSUMERS (2007), http://appanet.org/files/PDFs/SynapseLMPElectricityMarkets013107.pdf [hereinafter SYNAPSE LMP STUDY]. "There is simply no evidence that the price signaling associated with LMP has been an effective spur to investment in generation, transmission or demand response initiatives, and some evidence to the contrary." *Id.* at ix, x. New generation that has been constructed in RTO regions employing LMP has in many cases been built or anchored (through the execution of a long-term agreement to purchase the output) by not-for-profit public power entities. For example, in the NY ISO, the New York Power Authority (NYPA), and the Long Island Power Authority (LIPA) have either constructed or signed power purchase contracts that made possible a number of new generating units, including units in the well-known New York City load pocket. Such units include NYPA's 500 megawatt (MW) combined cycle natural gas fired power plant constructed next to an existing power plant (the Charles Poletti plant) in Astoria, Queens, which went into service in December 2005, and LIPA's long-term contract to anchor the Caithness Long Island Energy Center, a 350 MW natural-gas fired plant under construction that is estimated to go in service in the summer of 2009. These units are a product of the public power systems' service missions, rather than any intent to profit from LMP-based price signals.

41. Most FTRs carry a term of a year or a month. In response to new legal requirements included in Section 1233(b) of the Energy Policy Act of 2005, Pub. L. No. 109-58, § 1233(b), 119 Stat. 594, 960 (2005) (implementing new Section 217 of the FPA in RTO regions), the FERC, in Order No. 681, required RTOs to develop long term (*e.g*., 10 year) financial transmission rights (LTTRs) meeting certain guidelines set out in the order. Order No. 681, *Long-Term Firm Transmission Rights in Organized Electricity Markets*, 71 Fed. Reg. 43,564 (2006), *on reh'g*, Order No. 681-A, 117 F.E.R.C ¶ 61,201 (2006) [hereinafter Order No. 681]. These LTTRs, however, are only now becoming available due to the time that was required for the FERC to develop the relevant guidelines governing these rights and to approve the subsequent often-controversial filings the various RTOs made to implement LTTRs. *See, e.g*., *PJM Interconnection, LLC*, 117 F.E.R.C. ¶ 61, 220 (2006) (accepting PJM's LTTR proposal with modifications), *on reh'g*, 119 F.E.R.C. ¶ 61,144 (2007), *on further reh'g*, 121 F.E.R.C. ¶ 61,073 (2007). In some cases, implementation of LTTRs has been delayed due to extended controversies regarding the specific features these rights will impart to their holders. *See, e.g., ISO New England & New England Power Pool*, 122 F.E.R.C. ¶ 61,173 (2008) Compliance Filing, made in response to the FERC's order in *ISO New England, Inc*., 122 F.E.R.C. ¶ 61,173 (2008), and the June 17, 2008 Protest of the New England Public Systems to that compliance filing. LTTRs and the FERC's implementation of them are discussed in more detail in Jay Morrison, *EPAct '05 Implementation: Is FERC in Full Compliance,* 28 ENERGY L.J. 631, 650-653 (2007) [hereinafter MORRISON]. The lack of availability of LTTRs (as well as the

The number of FTRs an RTO issues is limited by the physical capability of its transmission network, which varies depending on the requested source/sink pairings and over time, depending on forecasted operating conditions and future loads.[42] Some LSEs have suffered cuts in their financial rights allocations when forecasted changes in operating conditions caused the RTO to impose reductions.[43] In addition, the amount of revenue FTRs actually provide to their holders is not guaranteed at any particular level and can fluctuate due to a number of factors.

Moreover, hedge funds, investment banks, and other financial entities have begun purchasing FTRs through the RTO-run auctions, further exposing transmission customers to potential financial risks. These entities often have no stake in the market except a financial one and are therefore bidding on these FTRs purely for speculative purposes.[44] LSEs, industrial customers, and other wholesale power buyers must obtain FTRs as a hedge against real congestion costs incurred as a result of their physical power supply transactions, and therefore participate in these markets out of necessity.[45]

The more recently implemented locational capacity markets, intended to induce an adequate level of generation supply and demand response not previously produced by LMP, have proven to be very controversial, due to their high prices and doubtful efficacy in supporting the development of substantial new generation resources.[46] Supporters of these markets, however, point to the

inability to hedge marginal losses) has increased the difficulties for LSEs in RTO regions that are in fact interested in developing new long-term generation resources, due to the increased financial uncertainties.

42. Order No. 681, *supra* note 41.

43. *See, e.g.*, *Borough of Chambersburg, Pennsylvania v. PJM Interconnection, LLC*, 117 F.E.R.C. ¶ 61, 219 (2006) (denying complaint by two PJM LSEs regarding substantial reductions in their respective ARR allocations for the 2006-2007 PJM power supply year), *reh'g denied*, 119 F.E.R.C. ¶ 61,166 (2007).

44. In December 2007, two hedge funds defaulted on eighty-five million dollars in payments to PJM after they suffered financial losses associated with FTRs they had purchased for speculative purposes. The two funds had purchased "counterflow positions" that historically would have earned them money. When PJM-controlled transmission lines were shut down for routine maintenance in New Jersey, however, the power flows on the system changed, resulting in an obligation to pay by the holders of these FTRs. Both funds then defaulted on their financial obligations associated with these FTRs; *see, e.g.*, PJM News Release, PJM Completes Analysis of Recent Market Payment Default, (Dec. 26, 2007) (http://www.pjm.com/contributions/news-releases/2007/20071226-credit-default-news-release.pdf). PJM subsequently filed a complaint against a group of commonly-controlled LLCs that included one of the two hedge funds, Power Edge, LLC. PJM has alleged that this family of LLCs manipulated PJM's FTR and DA energy markets, and is seeking restitution and other remedies. *PJM Interconnection, LLC v. Accord Energy, LLC*, 123 F.E.R.C. ¶ 61,103 (2008). On April 30, 2008, the FERC issued an order holding PJM's complaint in abeyance pending the outcome of its own staff's investigation into this matter. *Id.* Unless this family of LLCs is required to disgorge monies to remedy the defaults, it appears that other PJM customers will have to cover the FTR revenue shortfalls.

45. CONSUMERS IN PERIL, *supra* note 5, at 14.

46. See, e.g., *PJM Interconnection*, LLC, 117 F.E.R.C. ¶ 63,036 (group of PJM customers requested a FERC technical conference to examine the results of the first four locational capacity auctions run by PJM, alleging those auctions have resulted in twenty-six billion dollars in capacity costs with little resulting increased capacity). In response, the FERC ruled on April 17, 2008, that it was premature to hold such a conference, given that PJM is currently evaluating the performance of its RPM with the assistance of an outside consultant. The FERC did order PJM to have its consultant incorporate the issues raised by the buyers group into its evaluation, and indicated that a technical conference might be warranted at a future time. *PJM Interconnection*, LLC, 123 F.E.R.C. ¶ 61,037 (2008). On May 30, 2008, however, certain members of the buyers group filed a complaint against PJM, seeking restitution of a substantial percentage of the dollars PJM

participation of demand-side resources in them as a positive outcome, and argue that these markets must be given time to develop.[47]

Buyers and sellers in Day-Two markets can minimize purchases and sales of energy and capacity in the RTO-run markets by entering into individual power supply contracts (called "bilateral" contracts). But, the forward prices for energy sold under those contracts are substantially influenced by the prices the sellers can obtain for their power in the RTOs' centralized markets.[48] The relationship between the prices sellers can obtain in RTO-run energy and ancillary services markets, and the prices sellers charge under bilateral agreements, is explained at length in a paper by Frank Wolak and Shaun D. McRae.[49] As they explain:

> [b]ecause the [forward-price] forward contract obligations limits the incentive of suppliers to exercise unilateral market power in the short-term market, one might expect a firm with a significant ability to raise short-term prices to avoid signing forward contracts unless it receives prices that yield the same level of profits that it expects to earn from selling in the short-term market.[50]

This, in fact, has been the experience of many smaller LSE buyers in RTO regions; the prices they are offered under bilateral contract offers are essentially the forward version of the prevailing spot market prices those generation sellers can obtain, often with a premium added. Hence, very substantial volumes of power in RTO regions are sold through the RTOs' centralized markets.

It is uncommon to see bilateral contracts in RTO regions for terms longer than five years (unlike bilateral contracts in regions without RTOs, which can extend for terms as long as thirty years). Most such contracts only require the provision of energy; they are not tied to specific electric generating resources, and therefore cannot be used to meet a buyer's locational capacity market obligations. These bilateral contracts are often drafted as "seller's choice

LSEs are obligated to pay as a result of the first four RPM auctions. Md. Pub. Serv. Comm'n v. PJM Interconnection, LLC, Docket No. EL08-67-000. (Complaint filed May 30, 2008) [hereinafter MPSC Complaint]. The Commission dismissed the complaint in an order issued on September 19, 2008. *Md. Pub. Serv. Comm'n v. PJM Interconnection, LLC*, 124 F.E.R.C. ¶ 61,276 (2008). It did, however, grant on the same day in a separate order the earlier-filed request for a technical conference, ordering it to be held in February 2009. *PJM Interconnection, LLC*, 124 F.E.R.C. ¶ 61,272 (2008).

47. *See, e.g.*, PJM Press Release, PJM Reliability Pricing Model Producing Results, (July 13, 2007) (http://www.pjm.com/contributions/news-releases/2007/20070713-2nd-rpm-results.pdf) ("PJM Interconnection's new method of pricing electric capacity is producing the intended results: more demand response, reduced power plant retirements and additional generation."); P3 Group News Release, Energy Group Releases Comprehensive Study on Benefits of Reliability Pricing Model (May 5, 2008) (http://www.p3powergroup.com/siteFiles/News/63E8F8535A7B03CA41B67B1D1BA54BB6.doc) (P3, the PJM Power Providers Group, quoting Robert Stoddard of CRA International as stating in regard to RPM, that '"there is substantial evidence to believe it is working reasonably well and can, with modest improvements, work even better. . . . If this system is given the proper opportunity, it can potentially save consumers a great deal.'"). *Id*.

48. CONSUMERS IN PERIL, *supra* note 5, at iv.

49. Frank Wolak & Shaun D. McRae, *Merger Analysis in Restructured Electricity Supply Industries: The Proposed PSEG and Exelon Merger*, November 2007, http://zia.stanford.edu/pub/papers/pseg_exelon_merger.pdf.

50. *Id.* at 22.

agreements," meaning the seller will determine exactly what generation sources the energy sold will come from at the time it is actually supplied.[51]

Bilateral contracts do not insulate the customer from the payment of LMP-based transmission congestion charges, which are collected through an additional charge on top of the RTO's "base" transmission rate. As discussed previously, LSEs must obtain FTRs or LTTRs[52] to hedge such charges. Because of these LMP-based congestion charges, even LSEs that have their own generation resources are exposed to the vagaries of the RTO's spot market prices, to the extent they do not hold sufficient FTRs to offset the congestion charges associated with their own power supply arrangements, or those FTRs "go negative," requiring the holder to pay revenues to the RTO.

A recent study which the APPA commissioned examining the relationship between RTO-run spot markets and bilateral contracting in RTO regions found that power supply transactions in the organized markets are dominated by the spot markets, even when much of the energy used to serve load is not directly procured through the RTO's spot markets. Regulatory uncertainty, lack of adequate long-term transmission planning, and lack of LTTRs[53] have all impeded buyers' willingness to transact on a bilateral, long-term basis, while the lack of risk associated with transacting in the spot market described by Wolak and McRae has limited sellers' incentives to transact bilaterally. One exception, however, is the market for renewable resources, where LSEs are often required to procure renewable resources, future emissions and fuel costs are non-existent,

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51. One commonly-used example of such a product is the "Into-Seller's Daily Choice" product available as an option under the EEI-NEMA "Master Power Purchase & Sales Agreement," a widely used form agreement. Schedule P of that form agreement includes as a defined product the following:

> "Into ___________ (the 'Receiving Transmission Provider'), Seller's Daily Choice" means that, in accordance with the provisions set forth below, (1) the Product shall be scheduled and delivered to an interconnection or interface ("Interface") either (a) on the Receiving Transmission Provider's transmission system border or (b) within the control area of the Receiving Transmission Provider if the Product is from a source of generation in that control area, which Interface, in either case, the Receiving Transmission Provider identifies as available for delivery of the Product in or into its control area; and (2) Seller has the right on a daily prescheduled basis to designate the Interface where the Product shall be delivered.

The form agreement is available at EDISON ELEC. INST. & NAT'L ENERGY MARKETERS ASSOC., MASTER POWER PURCHASE & SALE AGREEMENT (2000) http://www.eei.org/industry_issues/legal_and_business_practices/master_contract/contract0004.pdf.

52. *See generally* discussion, *supra* note 41.

53. Order No. 681, *supra* note 41, at P 10:

> [T]he FTRs that transmission organizations currently provide to hedge congestion charges for using existing transmission capacity (as opposed to incremental transmission expansions) are generally available for terms of only one year or less. This can create uncertainty for the market participant who wants to procure supplies on a long-term basis because it will not know from year to year with any degree of certainty whether its award of FTRs will be sufficient to meet its needs. Some market participants have expressed concern that this uncertainty makes it more difficult to finance long-term power supply arrangements.

Id.

and developers of renewable projects are very interested in obtaining long-term recovery of their capital investment.[54]

III. COMPETITION AND RTO-RUN WHOLESALE ELECTRIC POWER MARKETS

A. What Is Required for a "Market" to Be Competitive?

Supporters of RTO-run centralized wholesale electricity markets and state retail access regimes commonly use the term "competitive" to describe these markets and programs.[55] They assert that wholesale electric power is essentially no different from other industries,[56] and all that needs to be done is to improve market rules and market oversight.[57] The answer to the threshold question –

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54. SYNAPSE LMP STUDY, *supra* note 40.

55. In fact, it is questionable whether the structural features of the electric industry lend themselves to successful competition. *See, e.g.*, ROSE & MEEUSEN, *supra* note 4, at 6:

> Electric market characteristics suggest that the market structure is not a robustly competitive one, as was hoped when restructuring began. Because of high supplier market concentration, the difficulty of entry from other firms to build new generation, limited entry from outside the area due to transmission access constraints, and existing market rules, the structure that is emerging more closely resembles that of an oligopoly, where there are only a few firms supplying all or most of the output, than a truly competitive marketplace. [Footnote omitted.] There is also an inelastic demand for electricity, particularly in the short-run, since customers have few practical substitutes. All these factors suggest the possibility that market conditions permit suppliers to exercise significant market power;

JOHN KWOKA, APPA, BARRIERS TO NEW COMPETITION IN ELECTRICITY GENERATION: REPORT TO THE APPA, June 2008, http://www.appanet.org/files/PDFs/BarrierPaper0604.pdf [hereinafter KWOKA 2008 STUDY):

> This report has documented the large number of impediments to this idealized process of entry into generation. These include conventional barriers to entry involving economies of scale and absolute cost advantages of incumbent generators. . . . These impediments also include regulatory issues as well as a variety of demand, cost and other uncertainties;

JOHN KELLY, APPA, EMRI: DO COMPETITION AND ELECTRICITY MIX?, http://appanet.org/aboutpublic/index.cfm?ItemNumber=18555 [hereinafter KELLY STUDY].

56. For example, the COMPETE Coalition has stated that:

> Competition keeps costs as low as possible, drives innovation, and produces the benefits customers are seeking -- because the customer calls the shots. This is true whether you're talking about telecom services, the advent of discount department stores, or the changes in the automobile industry in the last quarter century. It is also true for electricity.

COMPETE COALITION, SPEAKING TO THE BENEFITS OF ELECRICITY COMPETITION, Dec. 14, 2007, http://www.competecoalition.com/files/Proof%20Points.pdf.

57. Professor William Hogan, for example, recommends:

> little 'r' regulation through designing rules and policies that are the 'best mixture' to support competitive wholesale electricity markets. In pursuing the little 'r' approach, a key requirement is to relate any proposed solution to the larger framework and to ask for alternatives that better support or are complementary to the market design.

whether the economic, structural, and technical characteristics of electric power production and transmission are fundamentally compatible with truly competitive markets, is often implicitly assumed to be yes. Yet, even the economist Alfred Kahn, an early and leading proponent of deregulating electricity markets, recognized that a determination of whether market forces could sufficiently discipline prices and guide investment decisions "would have to take into account... the extraordinary and in some respects literally unique characteristics of this industry."[58]

Addressing the question of whether true competition is achievable in RTO-run centralized wholesale electricity markets first requires a common understanding of the term "competition."

The conventional textbook definition of a competitive market requires numerous buyers and sellers, no barriers to entry, low transaction costs, price flexibility in response to underlying cost changes, the ability of buyers to react to increases and decreases in price (elasticity of demand), perfect information, and foresight by buyers and sellers.[59] While the textbook definition of competition is likely too stringent as a practical matter, the listed characteristics still serve as a useful guide. If too many of these characteristics are missing from an industry, policymakers should be concerned about relying primarily on competitive forces to discipline prices. Columbia University economist Joseph Stiglitz, a Nobel laureate, provides what he calls a simple "old-fashioned" definition of competition: "rivalry among firms to supply the needs of consumers and producers at the lowest price with the highest qualities."[60] If such rivalry is present, then sellers will be "price takers," not "price setters," and consumers will benefit.

B. Structural Characteristics of Electricity Markets

Price competition is especially important in electric power markets. In other industries, lack of vigorous price competition may not be a major problem because firms can compete by improving existing products or introducing new ones. But this is generally not so for electricity. Price is essentially the only dimension over which suppliers can compete, and if suppliers are not vigorously competing on the basis of price, then consumers will not be better off. (One notable exception is the offering of "green power," where consumers can purchase electricity generated by renewable energy

William Hogan, Comments at the Federal Energy Regulatory Commission Conference on Competition in Wholesale Power Markets: Acting in Time: Regulating Wholesale Electricity Markets (May 8, 2007) (http://ksghome.harvard.edu/~whogan/Hogan_FERC_050807.pdf).

58. Alfred E. Kahn, *The Deregulatory Tar Baby: The Precarious Balance Between Regulation & Deregulation, 1970-2000 & Henceforeward*, 21 JOURNAL OF REGULATORY ECONOMICS 35, 46 (2002).

59. There are a number of sources for the standard definition of competition. DONALD WALDMAN & ELIZABETH JENSEN, INDUSTRIAL ORGANIZATION: THEORY AND PRACTICE Ch.3 (3 ed., Addison-Wesley 2007).

60. JOSEPH STIGLITZ, WHITHER SOCIALISM? 255 (The MIT Press 4th prtg. 1997).

facilities.[61] But, the "product" that is consumed – commingled electrons – is still the same).[62]

There are significant economic and structural impediments to competitive RTO-run centralized wholesale markets that policymakers cannot simply assume away. Structural characteristics inherent in the electric power industry raise substantial barriers to entry and, thus, severely limit competition. Other relevant characteristics impeding competitive forces include relatively inelastic short-run demand, the lack of storability of the "product," and the need for a reliable transmission system to bring electricity to consumers.[63]

The most obvious barrier to entry, perhaps, is the size of the capital investment needed to enter the generation market.[64] Other threshold questions confronting a potential competitor are, how much lead time it takes to enter the market, where to build a new generation plant, how to obtain access to the transmission grid, and, most importantly, whether there will still be the same level of demand for electricity once the new plant is built and what impact the addition of its new supply will have on prices.

A new competitor might see a market opportunity where prices have been high for a significant period of time, and so might believe this would be the case for the next year or two. But, it can take a minimum of five years to build a large fossil fuel-fired plant,[65] and even longer for a nuclear plant.[66] Price and

61. ANNE M. MCSHEA, NE. SUSTAINABLE ENERGY ASSOC., GREEN POWER YOU CAN CHOOSE (2001) http://www.nesea.org/publications/NESun/you_can_choose.html.

62. The chances that an end-use consumer purchasing such "green" power is actually purchasing the specific electrons he or she contracted to buy from a specified renewable generation resource are very low, given the operating characteristics of an interconnected electric transmission system. New York v. FERC, 535 U.S. 1, 7-8 n. 5 (2002) ("'[e]nergy flowing onto a power network or grid energizes the entire grid, and consumers then draw undifferentiated energy from that grid.'") (emphasis in original, citations omitted); Fort Pierce Util. Auth. v. FERC, 730 F.2d 778, 782 (D.C. Cir. 1984) ("A transmission network functions more like a reservoir: a given amount of power enters the system at one point and a like amount is delivered at another point").

63. Michael Dworkin & Rachel Goldwasser, *Ensuring Consideration of The Public Interest in The Governance And Accountability Of Regional Transmission Organization*, 28 ENERGY L.J. 543 (2007).

64. According to the Energy Information Administration (EIA), a new 500-600 MW base-load coal plant costs about 800 million dollars and a new comparably sized nuclear facility costs more than a billion dollars. A 400 MW advanced gas and oil fired combined cycle is estimated to cost about 240 million dollars. EIA, ASSUMPTIONS TO THE ANNUAL ENERGY OUTLOOK 2008, 79 tbl.38 (June 2008), available at http://www.eia.doe.gov/oiaf/aeo/assumption/pdf/0554(2008).pdf. Moreover, these costs are steadily increasing. See, e.g., C.E.R.A. News Release, Construction Costs for New Power Plants Continue to Escalate: IHS CERA Power Capital Costs Index (May 27, 2008) (http://www.cera.com/aspx/cda/public1/news/pressReleases/pressReleaseDetails.aspx?CID=9505).

65. In more recent experience, it can take almost that long even to obtain the necessary authorizations. The APPA commissioned a paper outlining the recent difficulties experienced by both traditional utilities and independent power producers in constructing new generation facilities. J. Edward Cichanowicz, *Discussion & Examples of Entry Barriers in the Electricity Generation Market*, APPA, July 31, 2008, http://www.appanet.org/files/PDFs/BarrierssupAug08.pdf [hereinafter Cichanowicz Study]. He notes:

> [a]s recently described by a veteran permit writer, the task of preparing an environmental permit application [for a new coal plant] requires 4 to 8 months, and subsequently working with various state agencies to secure the permit requires an additional 12 to 18 months. Then, an additional one to three years (or more) can be required to attempt to resolve the lawsuits [citation omitted].

demand forecasts become less reliable that far out, and risks increase correspondingly.[67] Without a long-term commitment by one or more buyers to purchase the generation facility's output, financing can become problematic. Hence, the longer it takes to enter the market, the less certain the amount of future revenues becomes. These factors pose a significant barrier to entry.

The power of incumbency is also a significant entry barrier. Incumbent generators control many of the best sites for new generation, giving them a significant absolute cost advantage.[68] These generators can add capacity at existing sites by repowering and increasing the size of existing units, building new units in their place, or by adding new units to old ones at existing sites.[69] In contrast, new entrants face the challenge of finding sites not too far from high-population areas, transmission lines, sources of water, rail lines, etc., depending on the type of unit they wish to build. Consequently, new entrants often have to build plants at less desirable locations where they may not have convenient access to other necessary infrastructure.[70] If they do locate plants closer to end users, land values are likely to be high, and siting and environmental requirements more stringent and costly.[71] Hence, incumbent generators have a significant "built-in" competitive advantage, without having to take any affirmative actions to discourage or exclude potential competitors.[72]

As APPA explained in Consumers in Peril:

Id. at 4.

66. KWOKA, 2008 STUDY, *supra* note 55, at 38, Table 2 (citing EIA data estimating a six year lead time for advanced nuclear plants).

67. As the EIA has noted: "All long-term projections engender considerable uncertainty." EIA, ENERGY MARKET IMPACTS OF A CLEAN ENERGY PORTFOLIO, Feb. 2007, http://www.eia.doe.gov/oiaf/servicerpt/portfolio/uncertainty.html. Even short-term forecasts can err in demand projections. JAMES WILSON, APPA, RAISING THE STAKES ON CAPACITY INCENTIVES: PJM'S RELIABILITY PRICING MODEL (RPM) (Mar. 14, 2008), http://appanet.org/files/PDFs/RPMreport2008.pdf [hereinafter WILSON STUDY] (noting that "[e]ven PJM's near-term forecasts can overstate peak loads and reliability requirements, with costly consequences.").

68. KWOKA, 2008 STUDY, *supra* note 55, at 21.

69. KELLY STUDY, *supra* note 55, at 13.

70. *Id.*

71. *Id.*

72. In addition, many of the independent power producers that would be considered new entrants cut their teeth in the 1990s and early 2000s developing new gas-fired generation. Development of new coal or nuclear units, however, is a much more complex and difficult proposition. Cichanowicz Study, *supra* note 65, at 19-20:

> [t]he record of cancellations [of coal-fired projects] suggests that some project developers, depending on their experience, may not anticipate the regulatory delays and capital cost barriers associated with coal-fired generation. Of the coal-fired generating units that were successfully permitted and are currently under construction, none are developed exclusively by coal-based developers. Developers for which prior experience is limited to natural gas may not have appreciated the complexity, or the resistance encountered, to a coal-based project.

In contrast, new entrants play a much larger role in the development of renewables. "New entrants will likely continue to play a significant role in renewable power generation, particularly in the fast-growing solar 'space.'" *Id.*

> Advocates of RTO-run centralized markets have touted the entrance of "merchant generators" into the marketplace as a sign that these markets are competitive. But many of these companies are the deregulated generation affiliates of former vertically-integrated electric utility companies. Many of the generation units in their portfolios are the same units that the vertically integrated utility built prior to restructuring to serve their retail customers. Thus, the generation portion of their businesses went from being a regulated monopoly to part of an unregulated oligopoly. [Footnote omitted.]
>
> For example, the 6,000 megawatts of electric generation capacity that Baltimore Gas and Electric Co., a state-regulated transmission and distribution utility, once owned is now owned by the company's unregulated affiliates within the Constellation Energy holding company. [Footnote omitted.] Constellation's "merchant" affiliates therefore do not face many of the high barriers to entry – such as financing the plant and locating a site – that a true new entrant would. This head start enhances the market power of these merchant affiliates of traditional utilities. They can charge prices substantially above their own economic costs of producing power and have little to fear from new entrants.[73]

If these affiliates do decide to consider the building of significant new generation facilities (as Constellation is proposing to add a new nuclear generation unit at its existing Calvert Cliffs site), they can leverage such projects off of their existing asset base and technological expertise.[74] "As a result, there are only a limited number of generation competitors in RTO markets, further undermining the ability"[75] of competitive forces to keep prices at reasonable levels.[76]

73. CONSUMERS IN PERIL, *supra* note 5, at 8.

74. *In re* Comm'ns Investigation of Investor-Owned Elec. Cos.' Standard Offer of Serv. for Residential & Small Commercial Customers in Md., No. 9117, slip op. at 3 (Md. Pub. Serv. Comm'n. July 3, 2008), http://webapp.psc.state.md.us/Intranet/CaseNum/CaseAction.cfm?RequestTimeout=500 (whether such dominant incumbent generators do choose to build new generation can be as much a political decision as a business decision. For example, in Constellation's case, it is well known that the Governor of Maryland and the MPSC are quite concerned about the lack of new generation being constructed in the state, and the possibility of future capacity shortages. In July 2008, the MPSC issued an order requiring the electric utilities it regulates to evaluate various long-term Standard Offer Service (SOS) power procurement plans. Evaluations are due to be filed on October 1, 2008. At least one of each utility's evaluations is to include new, utility-owned generation); *Constellation settlement bill amended*, THOMSON FINANCIAL NEWS, Apr. 4, 2008, www.forbes.com/markets/feeds/afx/2008/04/04/afx4855370.html (dominant incumbent utilities can also obtain bargaining leverage with state regulators and legislature by saying their unregulated affiliates might build such new generation facilities in other regions, rather than in their traditional service territories, thus raising the specter of inadequate future generation to serve the state. Constellation played such a card with Maryland when it said it might site its new nuclear generation in New York, rather than in Maryland); CONSTELLATION ENERGY GROUP, INC., SEC FORM 8-K CURRENT REPORT, EXHIBIT 99.1 5 (2008) http://files.shareholder.com/downloads/CEG/416036157x0xS1104659-08-20675/1004440/filing.pdf (the settlement that Constellation entered into with Maryland on March 27, 2008, resolving a number of pending court cases and state regulatory matters, specifically requires Constellation to "prioritize the development of a new nuclear plant at Calvert Cliffs over the development of a nuclear facility at any other site it controls." This is a clear sign that the state took Constellation's statements that it might locate its new nuclear unit elsewhere seriously enough to make it a condition of the settlement. Such strategies are less effective under traditional cost-of-service integrated service regimes, where the retail utility has a legal obligation to ensure adequate service to its retail customers in the state where it has obtained a utility franchise).

75. CONSUMERS IN PERIL, *supra* note 5, at 8.

Professor John Kwoka of Northeastern University has concluded in his study for the APPA that the barriers to entry into the generation market in terms of capital costs and lead times are substantial.[77] Other barriers include the regulatory approval processes, interconnection to the grid, and uncertainty regarding future demand and price of electricity. Incumbent owners of generation, however, often face lower barriers.[78] As noted above, such companies are often already in possession of the best locations for generation plants. Investment in new generation may also be difficult to obtain due to uncertainty over future demand, and policies affecting generation costs. As a result, investors are more willing to fund plants that have greater certainty of cost recovery. Professor Kwoka notes that the bulk of the generation construction in recent years has been carried out by vertically integrated utilities in states that have not restructured the electric utilities, and from municipally-owned utilities that have been increasingly seeking to integrate vertically.[79]

Despite these and other impediments, RTOs and RTO market advocates continue to assert that restructured wholesale electricity markets are competitive.[80] This assertion overlooks the basic physical characteristics of the production and delivery of electric energy and the economic characteristics of the industry. If RTO-run wholesale electric power markets were structurally competitive, then the market itself would produce the correct levels of investment in reliable and environmentally responsible electric service, and assure that electricity is produced and priced efficiently. There would be no

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76. PJM INTERCONNECTION, LLC, STATE OF MARKET REPORT VOLUME 2: DETAILED ANALYSIS, 17 at tbl.2-3 (Mar. 11, 2008), http://www2.pjm.com/markets/market-monitor/downloads/mmu-reports/2007-som-volume2-sec2.pdf [hereinafter PJM MARKET REPORT VOLUME 2] (for example, in PJM in 2007, the Herfindahl-Hirschman Index (HHI), a measure of market concentration, averaged 3,746 for peaking plants, well above the cut-off of 1,800 for what the Department of Justice considers a "highly concentrated market." (Peaking plants are relatively high-cost generation units that only generate electricity at times of high system demand). The average for intermediate plants was similarly high, at 2,158. (Intermediate plants are more expensive to operate than "base load" generation plants, which operate at virtually all hours, but less expensive than peaking plants)); U.S. DEPT. OF JUSTICE & FED. TRADE COMM'N., HORIZONTAL MERGER GUIDELINES (1997) http://www.usdoj.gov/atr/public/guidelines/horiz_book/15.html (an HHI of 1,800 represents about five or six firms with equal market shares. The Department of Justice regards markets with HHIs of more than 1,000 to be "moderately concentrated;" markets with HHIs of more than 1,800 are considered "highly concentrated").

77. KWOKA 2008 STUDY, *supra* note 55, at 35-36.

78. *Id.* at 6-8; KELLY STUDY, *supra* note 55, at 13.

79. KWOKA 2008 STUDY, *supra* note 55, at 15 n.22.

80. COMPETE COALITION'S MISSION, http://www.competecoalition.com/about (last visited Sept. 23, 2008) (for example, the COMPETE Coalition's mission statement says: "With passage of the Energy Policy Act of 1992, Congress brought the American tradition of competition to the most basic of public commodities – electricity…. Today, open and competitive wholesale electricity markets bring varied and crucial benefits to the nation."); PJM MARKET REPORT VOLUME 2, *supra* note 76, at 1.

The MMU concludes that in 2007:

- The Energy Market results were competitive;
- The Capacity Market results were competitive;
- The Regulation Market results cannot be determined to have been competitive or to have been noncompetitive;
- The Synchronized Reserve Markets' results were competitive; and
- The FTR Auction Market results were competitive.

Note that the PJM MMU concludes the market "results" are competitive, rather than the markets themselves).

need for complex sets of rules resulting from patchwork solutions that attempt to address continuing concerns about reliability, excessive prices, and the adequacy of future generation capacity, as there are today.[81]

We believe it is time to ask: are continuing concerns about adequate capacity, reliability, and exercise of generation market power in RTO-run centralized wholesale markets simply due to the fact that the industry and regulators have not yet been able to come up with the correct market design? Or is it because the basic characteristics of electric power markets ensure a substantial level of market power that cannot simply be designed away? Are the disconnects between how competitive markets should theoretically perform and what is actually happening in RTO-run centralized electric power markets due to faulty market design, or, alternatively, do they reflect faulty assumptions regarding what can realistically be done, given the basic structural features of these markets? We believe that a detailed, unbiased study of the inherent economic conditions of the electric power industry and the basic design features of RTO-run centralized markets would raise serious questions about the competitiveness of these markets and their ability to discipline wholesale prices to just and reasonable levels.[82]

It is important, however, to draw a clear distinction between our concern about the justness and reasonableness of wholesale electric rates determined in RTO-run centralized markets and the use of time-of-use retail rates. We do believe prices to retail consumers can appropriately vary by time of use to reflect the varying costs of generating electric power in different hours at different levels of customer demand. If a retail customer is consuming power on a hot summer afternoon, when system demand is high and more expensive generation units are running, that customer should be aware of the cost of the full portfolio of resources needed to provide electricity at that time, and should have the ability to respond. Moreover, demand response measures to allow customers to respond more effectively to these time-varying costs should be implemented. But,

81. Gary Newell, Remarks at the Center for Research in Regulated Industries Advanced Workshop in Regulation and Competition (May 15, 2008) (in his paper, *Second-Generation Regulatory Capture as an Explanatory Factor in the Performance of Regional Transmission Organizations*, Gary Newell has noted that the extent to which complex rules have evolved to govern the operation of the relevant market is in itself an indicator of "regulatory capture" of RTOs by their resident generators. He also notes that "the very complexity of the rules functions as a barrier to entry by smaller competitors.") (paper available from the author).

82. The Government Accountability Office (GAO) in September 2008 issued a report calling into question FERC's current approach to regulation of RTOs. ELECTRICITY RESTRUCTURING – FERC COULD TAKE ADDITIONAL STEPS TO ANALIZE REGIONAL TRANSMISSION ORGANIZATIONS' BENEFITS AND PERFORMANCE, GAO Report 08-987 (September 2008) at 43, http://www.gao.gov/new.items/d08987.pdf:

> Experts, industry participants and FERC lack consensus about whether RTOs have provided net benefits to consumers. . . . FERC officials share the view that RTOs have resulted in benefits to the economy, such as new efficiencies in operating the regional transmission grid, but FERC has not conducted an empirical analysis to measure whether these benefits were realized or developed a comprehensive set of publicly available, standardized measures that can be used to evaluate RTO performance.

The GAO accordingly recommended that the FERC beef up its regulation of RTOs, finding that "it has become clear that FERC's efforts to regulate RTOs as it does utilities may no longer be sufficient." *Id*. at 58.

allowing variability in electric rates over time does not require, and should not serve as a pretext for, setting prices far above the economic costs of generation. If competitive forces are not disciplining wholesale prices in RTO-run centralized markets to levels that bear some relation to costs (marginal or otherwise), then we question whether such wholesale rates can be passed through in time-varying retail rates, even in the name of sending "price signals" to reduce consumption at peak periods, without violating the FPA's requirement that rates be just and reasonable. Similarly, lifting price caps in RTO markets during operating reserve shortages to allow retail consumers to see "scarcity pricing" signals would similarly result in unjust and unreasonable rates.[83]

C. Findings of EMRI Studies Regarding RTO-run Centralized Wholesale Markets

Because of the strong concerns the APPA's member public power utilities located in RTO markets expressed to the APPA regarding their increasing difficulties obtaining reasonably-priced power supply and transmission services, the APPA undertook its Electric Market Reform Initiative (EMRI). In 2006, the APPA commissioned a series of studies to gather more information about RTO-run centralized wholesale market operations and their associated impacts on consumers.[84] The purpose of these studies was to delve more deeply into assumptions and assertions often made by supporters of RTO-run centralized markets.[85] In our view, the findings of these studies paint a disturbing picture of RTO-run centralized markets and the state of "competition" in them. The remainder of this section describes the questions posed by these studies and their findings.

1. Analysis of Studies Assessing Costs and Benefits of Restructuring

The APPA first requested an in-depth examination of a group of then-existing studies regarding the benefits and costs of wholesale and retail restructuring, including a number of studies that RTO market proponents often cited. Professor John Kwoka reviewed these studies and found that the methodologies used in them fell short of the standards necessary for reliable economic research. As a result, he concluded there "is no reliable and convincing evidence that consumers are better off as a result of the restructuring of the U.S. electric power industry."[86]

Supporters of restructuring continue to cite, in support of their claims of benefits from RTO Day-Two markets, many of the studies that Dr. Kwoka

83. Notice of Proposed Rulemaking, *Wholesale Competition in Regions with Organized Electric Markets,* F.E.R.C. STATS & REGS. ¶ 32,628 at PP 97-128, 73 Fed. Reg. 12,576, 12,590-99 (2008) (FERC is proposing to require RTOs to implement some variant of such "scarcity pricing," as a way to stimulate additional demand response at the wholesale level).

84. INVESTIGATIVE STUDIES OF WHOLESALE MARKETS, http://www.appanet.org/aboutpublic/index.cfm?ItemNumber=21334 (last visited Sept. 19, 2008).

85. *Id.*

86. JOHN KOWKA, APPA, RESTRUCTURING THE U.S. ELECTRIC POWER SECTOR: A REVIEW OF RECENT STUDIES vii (2006), http://appanet.org/files/PDFs/RestructuringStudyKwoka1.pdf [hereinafter KWOKA RESTRUCTURING SURVEY].

critiqued.[87] Moreover, newer studies released by advocates of electric restructuring are often summations or quotes from other studies and comments, rather than original quantitative analyses.[88] As concerns over prices have risen, these studies have also increasingly made claims of much less quantifiable non-price benefits. For example, the COMPETE Coalition, in February 2008, released a study by National Economic Research Associates (NERA) asserting that "competition" or restructuring shifts risks from consumers to investors; leads to production at lowest achievable long-term costs; and encourages demand response, energy efficiency, and investment in renewable energy.[89] These claims are more subjective and difficult to prove than claims of lower prices due to competitive markets.

When substantive studies employing quantitative methodologies have been issued subsequent to Professor Kwoka's Restructuring Survey, APPA has attempted to undertake careful analyses of them. For example, APPA and the National Rural Electric Cooperative Association (NRECA) asked Laurence Kirsch and Mathew Morey of Christensen Associates Energy Consulting to review a study by Kira Fabrizio, Nancy Rose, and Catherine Wolfram, commonly cited for the proposition that restructuring has promoted improvements in the operational efficiencies of generation units.[90] Kirsch and Morey also reviewed, at the APPA's and the NRECA's, request the COMPETE Coalition's press release publicizing this study.[91]

Kirsch and Morey found that, in addition to several flaws in the study's methodology, the COMPETE Coalition's public statement that the study provides "'further evidence that competitive forces in restructured electricity markets drive efficiencies that benefit consumers by helping to drive down costs and reduce adverse environmental impacts'"[92] was misleading. They found that the study itself provided no evidence of how competitive forces work in

87. Letter from Vicky A. Bailey, FERC Commissioner 1993-2000, Nora Mead Brownell, FERC Commissioner 2001-2006, Jerry J. Langdon, FERC Commissioner 1988-1993, Elizabeth Anne Moler, Chair 1993-1997, FERC Commissioner 1988-1993, Pat Wood, III, Chairman 2001-2005, Linda Breathitt, FERC Commissioner 1997-2002, James J. Hoecker, Chairman 1997-2001, Commissioner 1993-2003, William L. Massey, Commissioner 1993-2003, & Donald F. Santa, Commissioner 1993-1997 to Policy Makers (May 31, 2007), *available at* http://www.paenergynews.com/pdfs/openletter_062707.pdf ("Open Letter to Policymakers" from a group of former FERC Commissioners, which cites the thirty-four billion dollars in savings estimated in a Cambridge Energy Research Associates (CERA) study. That study was released in October 2005, over a year and a half prior to the letter, and was addressed by Dr. Kwoka in his Restructuring Survey).

88. *See, e.g.*, COMPETE News Release, Electricity Market Policies Faring Well, Benefiting Consumers: Recent Developments Support Electricity Competition (Feb. 26, 2008) (http://www.competecoalition.com/newsroom/electricity-market-policies-faring-well-benefiting-consumers) [hereinafter NERA REPORT].

89. *Id.*

90. CATHERINE WOLFRAM, ET AL., DO MARKETS REDUCE COSTS? ASSESSING THE IMPACT OF REGULATORY RESTRUCTURING ON U.S. ELECTRIC GENERATION EFFICIENCY, 97 AMERICAN ECONOMIC REVIEW 2007, 1250-1277 (2007), http://faculty.haas.berkeley.edu/wolfram/Papers/FRW_AER_0607.pdf.

91. COMPETE News Release, Independent Study Finds Electricity Market Reforms Produced "Substantive" Improvements in Generation Efficiency (Sept. 27, 2007) (http://www.competecoalition.com/newsroom/independent-study-finds-electricity-market-reforms-produced-%E2%80%9Csubstantive%E2%80%9D-improvements-gene).

92. *Id. quoting* former FERC Commissioner William Massey.

restructured environments, or whether any cost reductions resulting from increased operational efficiencies were in fact passed on to consumers.[93]

The Electric Power Supply Association (EPSA) also repeatedly makes the claim of improved efficiencies from electric restructuring. In an April 2008, "PowerFact" fact sheet, the EPSA stated: "...utilities have little incentive to maximize efficiency when they can include many cost overruns in their rate base. Competitive suppliers on the other hand, have every incentive to constrain costs because their investors, as opposed to captive ratepayers, are financially responsible for new construction."[94] The document went on to list a series of power plant cost overruns that occurred for projects undertaken by vertically integrated IOUs or public power utilities.[95] The document claims that "utilities have little incentive to maximize efficiency when they can include many cost overruns in their rate base."[96] It contains, however, no comparable data for the current projects of unregulated power suppliers indicating that they have not experienced similar increases in project costs, even though it notes that "[p]ower plant developers in all regions of the country are facing rising construction

93. LAURENCE D. KIRSCH & MATHEW J. MOREY, CHRISTENSEN ASSOCS. ENERGY CONSULTING, THE COMPETE COAL. OVERSELLS INDEP. STUDY FINDINGS (2007), http://appanet.org/files/PDFs/CompeteCritiqueChristensen12%2D3%2D07.pdf. The experience of APPA net-buyer members purchasing power in RTO regions has been that sellers of power, rather than passing any cost savings arising from efficiencies on to buyers, have priced their power under bilateral agreements based on the projected prices available to them in the RTO-run centralized spot markets. As discussed above, Wolak and McRae explain the economic underpinnings for this pricing paradigm. As also discussed above, the prices set in an RTO's centralized DA and RT markets are based on a bid-based single-clearing price that may in fact have little relation to *any* seller's costs, much less reflect the efficiencies obtained by particular sellers. Hence, it is highly questionable whether any savings from efficiencies, assuming they exist, are being passed on to consumers in RTO regions.

94. EPSA, RISING UTIL. CONSTRUCTION COSTS IN REGULATED STATES PLACE CONSUMERS AT RISK (2008), http://www.epsa.org/forms/uploadFiles/B91600000049.filename.EPSA_PowerFact_-_Rising_Utility_Construction_Costs_in_Regulated_States_Place_Consumers_at_Risk_Progress_2.pdf [hereinafter EPSA]. In a rising cost environment, the rational economic response of merchant generators with substantial existing generation fleets is primarily to rely on those units to produce higher profits as they become more valuable due to increases in demand. Those generators that do consider proposing new units have, in many cases, included in their pricing terms offered to buyers provisions to account for cost uncertainties and possible foregone profit opportunities in RTO-run spot markets, which have the effect of shifting the associated risks in large part back to the buyers. This may explain why some public power entities in RTO regions are choosing to construct their own new generation, rather than entering into long-term purchased power agreements with merchant generators. For example, the Prairie States Energy Campus, a new 1,600 MW coal-fired power plant in southern Illinois currently under construction and projected to come on line in the 2011-2012 timeframe, includes among its equity owners American Municipal Power-Ohio, the Illinois Municipal Electric Agency, the Indiana Municipal Power Agency, the Kentucky Municipal Power Agency, the Missouri Joint Municipal Electric Utility Commission, and the Northern Illinois Municipal Power Agency. WELCOME TO THE PRAIRIE STATE ENERGY CAMPUS: NEWS, http://www.prairiestateenergycampus.com/index-ie.html (last visited Sept. 23, 2008).

95. EPSA, THE COST OF NEW GENERATION CONSTRUCTION 1-2 (2008), http://www.epsa.org/forms/uploadFiles/C12D0000000A.filename.EPSA_-_Cost_of_New_Generation_Construction_-_May_27,_2008.pdf.

96. *Id.* at 1. In our view, EPSA's claim, at least as it relates to public power systems, is incorrect. Since public power systems are owned by their ratepayers and operate on a not-for-profit basis, they have every incentive to bring projects to completion at the lowest possible "all-in" cost. Even in the case of investor-owned utilities, the prospect of cost disallowances by their state public utility commissions in subsequent prudence reviews can act as a rein on expenditures.

costs."[97] Nor does the EPSA state that if unregulated power suppliers have incurred such increased costs, ratepayers have nonetheless been insulated from paying them by market forces. Given the rising costs of developing new generation for all suppliers, regulated and unregulated, this omission is significant.

As the Cichanowicz Study makes clear, rising construction costs, difficulties in obtaining regulatory and environmental clearances, and other factors have caused both regulated utilities and independent generators to abandon or radically revamp many proposed generation projects. No developer of new generation has been immune to these problems.[98] When regulated utilities must abandon such a project, however, they cannot at the same time abandon their service obligations to their customers; they must somehow find other ways to ensure that they have adequate resources in the future to serve their retail customers' needs. Unregulated merchant generators have no such overarching service obligation.

Much time, energy and expense has been expended by all sides producing "dueling studies" regarding the costs and benefits of RTO-run centralized markets. In our view, informed by both the literature and the actual experience of the APPA members in RTO regions, it is difficult to conclude that consumers have benefited from the implementation of these markets. That view is supported by the additional studies discussed in the remainder of this section.

2. Review of Restructured Wholesale Electricity Markets Outcomes

In addition to reviewing the studies done by others regarding the costs and benefits of restructuring, the APPA, as part of its EMRI effort, commissioned a number of original studies reviewing various aspects of RTO-run centralized markets.

a. Profitability of Sellers

In the APPA's view, one important indicator of whether "competition" is disciplining prices to just and reasonable levels is the profitability of the generators making sales into these markets.[99] The APPA, therefore, asked independent consultant and financial analyst Edward Bodmer to look at the current and future profitability of the five largest sellers of unregulated wholesale power in PJM.[100] Using publicly available data, Bodmer calculated

97. *Id.* EPSA subsequently released a paper on rising construction costs, which of course are faced by all suppliers (regulated and deregulated).

98. Of course, the relative impact of such project cancellations and downscaling is much different for incumbent generators than for new entrants. In the case of incumbents, their existing generation becomes relatively more valuable and profitable; new entrants, however, simply cannot participate in the market.

99. APPA, Market Rates Should be Allowed Only Where Markets are Competitive, PUB. POWER WEEKLY, July 12, 2004.

100. EDWARD BODMER, APPA, THE ELEC. HONEYPOT: THE PROFITABILITY OF DEREGULATED ELEC. GENERATION COS. (2007), http://appanet.org/files/PDFs/Bodmerstudywappendices.pdf [hereinafter BODMER]. Bodmer calls these five sellers the "Core PJM Companies," and notes that the group includes affiliates of formerly vertically integrated, state regulated utilities, such as:

the earnings by shareholders in these PJM companies to be thirty-two billion and forty billion dollars greater than those for cost-of-service regulated utility companies, for a three and ten year time period, respectively.[101] Information these companies themselves have prepared for investors and analysts contains predictions of additional substantial profits upon expiration of state retail rate caps and full implementation of PJM's locational capacity market.

Bodmer concluded that the structural changes in the retail and wholesale markets have greatly contributed to the profitability of these firms. He found that the differential between market prices and variable costs resulting from the use of a single clearing price auction are a primary factor contributing to the strong financial results for companies owning existing base load nuclear and coal plants.[102] Bodmer also concluded that the high profits attributable to these plants

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> Exelon, Constellation, PSEG, PPL and Allegheny. Generating assets owned by companies in this group were generally constructed pursuant to state regulatory approval, where funding of the plants was made possible by rate of return regulation. Much of the generating asset capacity owned by the Core PJM Companies comprises base load coal and nuclear facilities, and the bulk of that generating capacity is located in the PJM region.

Id. at 6. Bodmer also looked at the performance of what he called "Merchant PJM Companies"; this group included Mirant, NRG, Reliant, and Edison International's Midwest Generation. *Id.* The performance of the Merchant PJM Companies was more difficult to assess due to the dominant influence of non-PJM activities in their financial statistics and the unavailability of certain data for merchant companies. *Id.* at 25. Among other things, however, both Mirant and NRG went through bankruptcy proceedings.

101. *Id.* at 26.

102. *Id.* at 10. Some might argue that these strong financial results are justified, since ownership of coal and nuclear plants carries its own financial risks, which the unregulated affiliates are unlikely to be able to shift to ratepayers in future years. But many of the coal-fired generating plants in question are older, and their capital costs have already been fully paid for (perhaps more than once). If they become uneconomic to operate in future years due to high fuel costs or carbon constraints, they can be mothballed without leaving substantial unrecovered capital investments. In the case of nuclear units, decommissioning costs are no doubt a substantial concern at the end of the plant's useful life. But, the operators should have been putting aside funds to cover such costs over the useful life of the unit, as called for under Nuclear Regulatory Commission regulations. Moreover, at least one unregulated seller of nuclear power appears to be attempting to limit its liability for decommissioning costs through the device of putting the ownership of each nuclear unit in a separate LLC, with no recourse to the parent company if the LLC itself puts aside insufficient revenues to cover decommissioning costs. In such case, it appears that ratepayers might ultimately end up "holding the bag" for such costs in any event. Dave Gram, *Entergy's stance on decommissioning fund appears to change*, ASSOCIATED PRESS, June 4, 2008, http://www.boston.com/news/local/vermont/articles/2008/06/04/entergys_stance_on_decommissioning_fund_appears_to_change/:

> At least three times when its purchase of the Vermont Yankee nuclear plant was under review in 2001 and 2002, Entergy Corp. said publicly that it would assume the costs of decommissioning the plant when it eventually shut down. Now there are fears the decommissioning fund will come up short, possibly by hundreds of millions of dollars, and Entergy is saying something different. It turns out that decommissioning is not the responsibility of a $11 billion company that owns 10 nuclear plants around the country. Instead, it's on Entergy Nuclear Vermont Yankee, or ENVY, a subsidiary of New Orleans-based Entergy whose assets include one aging reactor in Vernon and some real estate in Brattleboro.

The Vermont legislature passed a bill, S. 373, designed to address this funding shortfall issue in its 2007-2008 legislative session. S.B. 373, Gen. Assem. (Vt. 2007). Governor Jim Douglas, however, vetoed the bill in May "is counter to a fundamental notion of restructuring – investors should not have been made better off simply by virtue of a changed regulatory framework."[103]

In a September 2007 update of his study using 2006 data, Mr. Bodmer found that these extra investor earnings had grown to between fourty-four billion and sixty-seven billion dollars.[104] Bodmer termed these profit levels "supra-competitive" and found that they are an indicator of a direct transfer of wealth from consumers to investors.[105] Basic economic theory supports the conclusion that such profit levels imply that these PJM sellers do not face substantial pressures to compete on the basis of price with other sellers.[106]

b. Relationship Between Generator Bids and Marginal Costs

In another attempt to gauge the level of competition and the resulting justness and reasonableness of the resulting rates, the APPA sought to investigate the relationship between generator bids in PJM's centralized spot markets and the generators' own marginal costs. At the APPA's request, London Economics International, LLC (LEI) conducted a computer simulation that attempted to ascertain what clearing prices would result if generator offers to sell power into PJM's spot markets were actually based on their short-run marginal costs, as the theory underlying the use of LMP postulates generators would offer.[107] LEI then calculated the difference between this simulated

2008. Peter Hirschfeld, *Symington tags Douglas with Bailout philosophy*, BARRE MONTPELIER TIMES ARGUS, September 30, 2008, http://www.timesargus.com/apps/pbcs.dll/article?AID=/20080930/NEWS02/809300352.

103. BODMER, *supra* note 100, at 3.

104. Affidavit of Edward Bodmer, appended to the Comments of the American Public Power Association filed in FERC Docket Nos. RM07-19-000 and AD07-7-000, September 14, 2007 ("Bodmer Affidavit"), at 9, *available at* http://www.appanet.org/files/PDFs/bodmer.pdf.

105. *Id.* at 3, 10.

106. *Id.* at 2-3 ("My research demonstrates that wholesale markets in RTO regions have failed to produce financial outcomes that are consistent with the operation of an efficient competitive market.") In the theoretical world of perfect competition, producers that can charge more than their short-run marginal costs plus a portion of their fixed costs will earn supra-competitive profits, and this "higher level of profits will attract new entrants to the market; the increased supply will cause downward pressure on price and restore profits to their normal levels under perfect competition." JULIA FRAYER, ET AL., LONDON ECON. INT'L, A COMPARATIVE ANALYSIS OF ACTUAL LOCATIONAL MARGINAL PRICES IN THE PJM MARKET & ESTIMATED SHORT-RUN MARGINAL COSTS: 2003-2006 (2007), at 39, http://appanet.org/files/PDFs/LEIReport2012007.pdf [hereinafter LEI STUDY]. Similarly, PJM's market monitor seems to adhere to this concept, stating that if prices are set, on average, "by marginal units operating at or close to their marginal costs . . . [t]his is strong evidence of competitive behavior." PJM MARKET REPORT VOLUME 2, *supra* note 76.

107. Of course, it is well-known that generators often submit offers that have little to do with their actual costs of generating an additional unit of power. *See generally* TIMOTHY MOUNT, APPA, INVESTMENT PERFORMANCE IN DEREGULATED MARKETS FOR ELEC.: A CASE STUDY FOR N.Y. STATE 13 (2007), http://www.appanet.org/files/PDFs/StudyMountEMRIreportNYISOCapacity09%2D07.pdf [hereinafter MOUNT STUDY]:

> There are two important characteristics of a deregulated electricity market that create regulatory problems. The first is that it is relatively easy for suppliers to speculate successfully in an electricity market and raise prices above the true marginal operating cost by submitting 'hockey-stick' supply curves.

Id. at n.13 (explaining a "hockey stick" supply curve):

clearing price and the actual clearing price.[108] It found that offers to sell electricity were often not tied to the marginal cost of producing that electricity.[109] For example, during peak periods in PJM in recent years, a range of less than ten percent to as much as twenty percent of the price is attributable to a markup above the short-run marginal costs of the generator whose bid cleared the market.[110] The LEI Study also showed a high degree of variation in the markup based on location, time of day, and across time.[111] LEI noted that PJM's markup index results are based on the production costs that generators report to the market monitor, rather than independently verified cost data.[112] (This data is not available to the public, so LEI could not review it.) Finally, LEI noted that certain data LEI needed to conduct its study was unavailable from PJM.[113]

The study that the APPA commissioned from Synapse Energy Economics to example LMP also reviewed generators' offers and their actual production costs. Synapse examined offer data from generators in both PJM and ISO NE and found that offers from the same generating unit fluctuated by as much as 100 dollars per megawatt-hour within one month.[114] Barring extraordinary circumstances, generating units typically have only minimal day-to-day changes in their production costs. The authors concluded that "[t]he evidence that this difference and other features like it represent market power......is compelling."[115]

c. Relationship Between Prices and Fuel Costs

A related indicator of the relationship between prices and actual costs is the degree to which electricity price changes are a reflection simply of rising fuel costs. Supporters of RTO-run centralized markets have often cited the increasing costs of fuels, principally the increasing cost of natural gas, as the reason for higher prices.[116] The APPA, therefore, commissioned a study by Dr.

> The offers submitted for most generating units are relatively close to the true costs, but for a few units, speculative offers are submitted that are much higher than the true operating costs. This leads to a kinked supply curve that looks like a hockey stick [citation omitted].

Id at n.13. As Mount explains, it is profitable, especially for larger firms, to employ such speculative bidding methods. *Id.* at 15-16. He notes that RTO market monitors have been mitigating such behavior, reducing the number of instances in which it occurs. *Id.* at 20. Nonetheless, its occurrence and the need to mitigate it cast substantial doubt on the economic theory underpinning LMP, *i.e.*, that generators will bid their marginal costs.

108. LEI, *supra* note 106.

109. *Id.*

110. *Id.* at 11 fig.1.

111. *Id.* at 9.

112. *Id.*

113. *Id.* at 77 (authors noted lack of access to detailed actual transmission congestion data and data on plant-specific operating constraints and other technical and operational constraints PJM faces).

114. SYNAPSE LMP STUDY, *supra* note 40, at 70-86..

115. *Id.* at 86 ("the potential for market power appears to be both present and significant").

116. For example, the FERC itself has stated that "[m]uch of the concern about competition in wholesale power markets can be traced to the effects of higher natural gas prices on wholesale electric power prices." Wholesale Competition in Regions with Organized Electric Markets, 72 Fed. Reg. 36,276, 36,379 (July 2, 2007) (to be codified at 18 C.F.R. pt. 35. *See also*, Letter from Paul L. Joskow & Alfred E. Kahn, to Policymakers (June 26, 2006), *available at* http://www.competecoalition.com/files/Letter_062606.pdf) (Letter sent by eight prominent economists states: "[C]ompetition and markets are not to blame for recent increases in electricity prices. The current high electricity prices are largely the result of dramatically higher fuel cost.").

Ken Rose to investigate this issue.[117] He found that fuel costs cannot fully explain the increase in wholesale electricity prices in RTO-run centralized markets.[118] According to Dr. Rose, "attributing electricity price increases to only the cost of fuels used to generate electricity is overly simplistic at best."[119] In fact, trends in PJM prices in 2005 and 2006 showed that, rather than moving in lockstep, electricity prices and fuel costs can sometimes even move in opposite directions.[120]

Dr. Rose's conclusions were recently confirmed in a paper by Robert McCullough and Anne Stewart.[121] Their analysis shows that when fuel costs are removed from prices, the differential between retail rates in RTO states and non-RTO states has actually widened over time; the differential was 2.5 cents in November 2007, compared to 1.1 cents in January 2003.[122]

d. RTOs and Resource Adequacy

Another critical measure of the success of a market structure is its ability to support reliable electricity service, by ensuring that sufficient generation and transmission facilities are in place to meet projected future consumer needs. RTO-run centralized markets, as originally envisioned, attempted to ensure future adequacy of facilities and resources largely through LMP-based pricing differentials intended to send "price signals."[123] In its 2007 Study of LMP,

117. KENNETH ROSE, APPA, THE IMPACT OF FUEL COSTS ON ELECTRIC POWER PRICES (2007), http://appanet.org/files/PDFs/ImpactofFuelCostsonElectricPowerPrices.pdf [hereinafter ROSE STUDY].

118. *Id.*

119. *Id.* Another relevant point in the fuel cost debate is that made by the late Dr. Michael Rothkopf. He pointed out that:

> [t]he rise in demand for natural gas is not a phenomenon that is independent of electricity deregulation . . . . Natural gas generation requires relatively little capital and little time. New capacity in deregulated markets has been heavily skewed towards natural gas. Thus, high gas prices are, in part, an effect of deregulation.

Letter from Michael H. Rothkopf, to ENERGYBIZ MAGAZINE, (Apr. 12, 2006), *available at* http://www.energycentral.com/centers/energybiz/ebi_detail.cfm?id=132.

120. ROSE STUDY, *supra* note 117, at 7 fig.7:

> electricity prices during the summer of 2005 (June through August) began to increase sharply in June before the natural gas cost increases [and] electricity prices increased during July and August 2006, including some daily price spikes, while the natural gas cost remained at levels seen in the first half of 2005.

121. ROBERT MCCULLOUGH & ANN STEWART, MCCULLOUGH RESEARCH, THE MISSING BENCHMARK IN ELECTRICITY DEREGULATION (Dec. 20, 2007) http://appanet.org/files/PDFs/RestructuringsMissingBenchmark.pdf [hereinafter MCCULLOUGH & STEWART (arguing that RTOs should file with the FERC their system lambdas (the variable cost of the last kilowatt produced over a particular hour) to allow analysis of the extent to which RTO hourly real-time prices are higher than marginal costs); Memorandum from Robert McCullough & Heidi Schramm to McCullough Research Clients (March. 19, 2008) (http://www.mresearch.com/pdfs/340.pdf).

122. *Id*. at 5 fig.4. Note that this differential is present despite the generation market mitigation regimes administered by the market monitors in each RTO region.

123. SYNAPSE LMP STUDY, *supra* note 40, at 68-69.

however, Synapse found that the areas where LMP prices are the highest, and, thus, transmission facilities are the most congested, do not correspond with the areas where the greatest investments in new generation and transmission have been made.[124]

The APPA also commissioned additional research on this issue, focusing on locational capacity market run by the NY ISO. This research was described in Consumers in Peril:

> Alarmed by the continuing lack of adequate investment, some RTOs are increasingly relying on locational capacity payments to generators to encourage the needed infrastructure investments. At APPA's request, Dr. Timothy Mount of Cornell University examined the effectiveness of the locational capacity market that the New York ISO administers. Dr. Mount found that the main accomplishment of the hundreds of millions of dollars consumers have paid to generators through the New York capacity markets has been to increase the market value of generators' existing capacity. He concluded "the evidence from New York shows that paying a large amount of additional money to generators in the [New York locational capacity] market does not guarantee that investment in new generating capacity will be made in a timely way." [Footnote omitted.] [125]

124. *Id.* at 17-33.

125. CONSUMERS IN PERIL, *supra* note 5, at 22. Dr. Mount recounted in his study the difficulties New York regulators have had in ensuring sufficient capacity:

> Since maintaining reliability is an essential requirement for sound public policy, New York regulators have made extensive efforts to deal with the imminent shortfall of generating capacity in the NYC region. Even though the initial shortfall of capacity in 2008 was less than two years away, the NYISO was still looking for solutions to the problem in April 2006. A letter sent to NYC distribution companies in the previous month asked for "alternative regulatory solutions" because an insufficient number of merchant projects had materialized by that time. The final plan for meeting reliability standards was released in August 2006. An important part of this plan involved intervention by the New York Power Authority (NYPA), which delayed the retirement of a large 888 MW oil plant (Poletti). In addition, a new cross-sound transmission link to PJM, financed by the Long Island Power Authority (LIPA), was counted as firm capacity. These interventions are not typical of a genuine merchant project initiated by market forces, and their necessity indicates that there are still substantial problems with the design of the NYISO markets.

MOUNT STUDY, *supra* n. 107 at 29. He further recounts:

> In 2005 and 2006, customers paid over $1 billion/year in the LICAP market in NYC [citation omitted] and merchant investors were still reluctant to commit to specific in-service dates for new generating units that have already received licenses for construction. This amount of money is enough to finance over 12,000 MW of new peaking capacity at a capital cost of $80/kW/Year [citation omitted], and this amount of additional capacity would more than double the installed generating capacity in NYC.

Id. at 37. His conclusions are supported by a 2007 report produced by the Committee on Energy of the Association of the Bar of New York City:

> It appears to the Committee that the true test has come in New York City and the energy and short-term capacity model currently in effect in New York State is simply not working to lead to development of the additional generation and transmission needed. The energy sector is of such significance to every aspect of the economy and to life itself that the State does not have the luxury of leisurely waiting for the market to correct itself [footnote omitted].

More recently, James Wilson of LECG, LLC analyzed for the APPA the first four auctions conducted under PJM's new locational capacity market, the Reliability Pricing Model (RPM).[126] Mr. Wilson found that RPM capacity prices in these auctions have been six to forty times higher than under PJM's prior capacity mechanism, and two to twenty times greater than the levels that PJM modeled in simulations conducted prior to the start-up of the market.[127] Because generation ownership in PJM is largely concentrated in the hands of a relatively small number of owners, there are incentives to withhold capacity and to offer capacity only at the highest prices allowed.[128] Wilson cited facts suggesting to him two instances of withholding in the Eastern and Southwestern zones in PJM.[129] Despite the high prices prevailing in these auctions, the data shows that the net increase in installed capacity is less than forty percent of the projected increase in needed capacity between 2007 and 2010.[130]

e. Administrative and Operational Costs of RTOs

The administration and operation of RTO-run centralized wholesale markets is very complex. Not only are consumers in RTO regions bearing the brunt of retail power prices higher than those in non-RTO regions, but their electricity bills also include the costs that RTOs charge simply to administer and operate their centralized markets. In an analysis prepared for the APPA, William Bateman found that RTO participants in 2005 paid more than one billion dollars in total administrative and operational costs to RTOs.[131] Each time that an RTO develops a major new market, such as CAISO's Market Redesign and Technology Upgrade (MRTU) or MISO's Ancillary Services Market (ASM), customers must absorb a new round of associated software development and other costs.[132] In addition, customers of the RTOs themselves must incur

COMM. ON ENERGY, ASS'N OF THE BAR OF THE CITY OF N.Y., ELEC. REGULATION IN THE STATE OF N.Y. 11 (2007) http://www.nycbar.org/pdf/report/Dereg_report.pdf

126. WILSON STUDY, *supra* note 67.

127. *Id.* at 5.

128. *Id.* at 9-10.

129. *Id.* at 6.

130. *Id.* at 38-39. On May 30, 2008, a group of customer representatives and state public utility commissions in the PJM region filed a complaint with the FERC seeking to recover a substantial portion of the dollars incurred through the first four RPM auctions. Maryland Pub. Util. Comm'n v. PJM Interconnection, LLC, (Notice of Complaint) (June 2, 2008) (No. EL08-67-000), http://www.pjm.com/documents/ferc/orders/2008/20080602-el08-67-000.pdf (last visited Sept. 24, 2008). This complaint was subsequently dismissed by the FERC, but a technical conference will be held in February 2009 to address certain of the issues raised, as described *supra* note 46.

131. APPA REPORT, *supra* note 15.

132. CALIFORNIA ISO, 2007 ANNUAL REPORT 40, http://www.caiso.com/2001/2001babd3960.pdf (shows under "Fixed Assets" 155.9 million dollars for "MRTU Work-in-progress." This figure presumably does not include 2008 expenditures. The CAISO recently once again delayed implementation of its MRTU, from the fall of 2008 until 2009, as discussed *supra* note 16). The public version of MISO's *Proposed Capital and Operating Budget* for 2008-2010 shows that actual and estimated costs of implementing the ASM for 2006-2008 are in excess of fifty million dollars. That budget can be found among the meeting materials for the Dec. 12, 2007 meeting of the MISO Board's Audit and Finance Committee. MIDWEST ISO, PROPOSED CAPITAL & OPERATING BUDGET FOR 2008-2010 (2007) http://www.midwestiso.org/page/Calendar%20Detail/MP_Details.cfm?meetingID=2540&nowDateTime=2007

increased internal administrative, personnel and other costs incurred simply to prepare for and participate in these RTO-run markets.[133] The high cost of administering and participating in RTO-run markets point up the need for an unbiased analysis of the costs and benefits of these markets before they are developed.

f. Availability of Data on RTO-run Centralized Markets

Evaluations of RTO-run centralized markets are hampered by the dearth of adequate data. The lack of data makes it very difficult to determine the extent to which the prices produced in RTO-operated markets in fact diverge from those that would result from a competitive market, as previously discussed. Moreover, it is very difficult to identify the degree to which participants exert market power or attempt to do so.

At the request of the APPA, William Dunn analyzed available RTO electricity market data to determine what information would be needed to allow adequate oversight of RTO markets.[134] He noted that:

> [t]he most frequently discussed concern associated with data release in electricity markets is whether the rapid release of data is more likely to facilitate competition or collusion. The most interesting aspect of this discussion is that market participants seem to be taking positions that are counterintuitive. Those who support continued confidentiality or delayed and masked release of data seem primarily to be the generation resource owners, who could be expected to benefit from data release if it would truly facilitate collusion. Conversely, it is the LSEs who generally advocate faster and resource-specific release of data, and they are the market participants who would be harmed by any collusion such data release facilitated.[135]

Dunn posited that this might be the case because "given the relatively small number of generators and their repeated market interactions, it is likely that the more active players already know, or can reasonably estimate, their competitors' information."[136] Dunn recommended that RTOs release resource and load-specific offer and bid data for their markets on the day following the operating day, with the specific generation owners identified, as is done in the markets in

-12-12&action=newDay. Implementation of the ASM has recently been delayed from September 2008 to January 2009.

133. At a November 2006 Congressional briefing, Michael Stuart, Senior Vice President for Wisconsin Public Power Inc. (WPPI), stated that MISO overhead costs have increased WPPI's revenue requirements by two percent, and have required the purchase of additional software and the hiring of a new employee to reconcile the many notices WPPI receives from MISO every day. Mark Gerken, Chief Executive Officer of American Municipal Power (AMP)-Ohio, said that AMP-Ohio spends five million dollars a year just in administrative costs made necessary by MISO. PUBLIC POWER DAILY, APPA, MIDWEST ISO HAS RAISED COSTS FOR CONSUMERS (2006), http://www.appanet.org/legislative/index.cfm?ItemNumber=18001.

134. WILLIAM H. DUNN, JR., APPA, DATA REQUIRED FOR MARKET OVERSIGHT-A CONCEPT FOR THE ELECTRIC MARKET REFORM INITIATIVE ("EMRI") OF THE APPA (2007), http://www.appanet.org/files/PDFs/dunn2007.pdf [hereinafter DUNN STUDY].

135. *Id.* at 5.

136. *Id.* at 6.

England, Wales, and Australia.[137] He also recommended providing the operating characteristics of the generation plants.[138]

The failure of RTOs to disclose such data makes it very difficult for those who wish to analyze RTO-run centralized markets (aside from the RTO market monitors and the FERC' staff) to examine bidding patterns and other information that could either lead to the conclusion that these markets are not producing competitive prices, or alternatively that they are doing so.[139] As Dunn notes:

> [a]s it stands now, market participants have to rely on a small priesthood of market monitors to validate the black box market results. No matter how good a job they do, these monitors do not have any money at stake, and the market participants have no way to validate the market monitors' performance. The more eyes looking at the data, the higher the chance that anomalous behavior by RTOs/ISOs and/or market participants will be detected.[140]

g. Available Data Regarding Retail Rates

With much of the actual wholesale generation market cost and bid data unavailable in RTO regions, those seeking information on RTO market performance are looking to the "bottom line;" the differential in the respective retail rates in regulated and deregulated states, taking into account rate caps. Retail rate comparisons between restructured states and states that have continued to employ traditional cost-of-service regulation are telling.[141] In restructured states where there are no longer transitional retail rate caps in place and customers are now fully exposed to market prices, average electric rates increased significantly more than in those states not in RTO regions that have retained regulated retail rates.[142] The gap between the regulated and deregulated states grew from 3.1 cents per kilowatt-hour in 1997 (the last full year before retail choice was effective in any state) to 4.4 cents per kilowatt-hour in 2007, an increase in the differential of forty percent.[143] Since many retail choice states required rate caps or rate freezes during a transition period, the rate gap narrowed until 2001, the year that California consumers were subject to market-based rates. (See figure below.)

137. *Id.* at 13-14. As Dunn recounts, the markets in Australia, and England/Wales do not have appeared to suffered adverse consequences, such as collusion, as a result of their data disclosure policies.

138. *Id.* at 14.

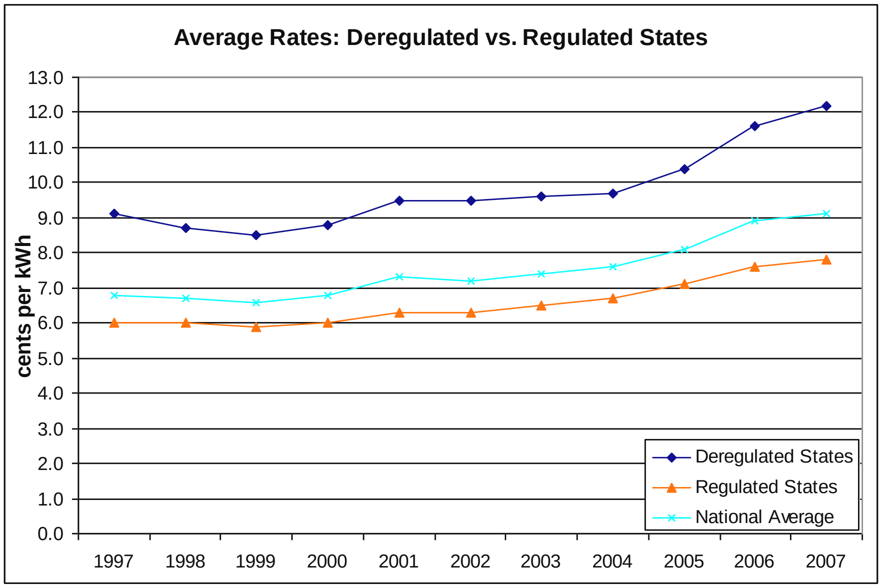
139. *Id.* at 6-7.

140. *Id.* at 8-9.

141. APPA, RETAIL ELECTRIC RATES IN DEREGULATED & REGULATED STATES: A TEN YEAR COMPARISON (2008), http://www.appanet.org/files/PDFs/10year.pdf [hereinafter APPA TEN YEAR COMPARISON].

142. *Id.* at 1-2.

143. *Id.* at 2.



Source: APPA Ten Year Comparison.[144]

One response from the supporters of restructuring to these price differentials has been to use a comparison of the percentage increases in the rates in restructured and non-restructured states as the basis for comparison, instead of the amount of increase in terms of actual rates, as well as to include retail access states with rate caps still in place in the restructured category.[145] Percentage increases, however, mask the fact that the restructured states began with higher rates; they undertook the restructuring experiment in the hopes of obtaining lower rates, a result that has clearly eluded them.[146] Rates in restructured states have increased rather than decreased, and the gap between rates in restructured rates and rates in regulated states is widening, even though all regions of the country are facing upward cost pressures on rates.[147] Moreover, rate caps are clearly a product of regulation; hence, including as restructured states those states that still have them, also masks the full impacts of restructuring.

Some proponents of deregulation further argue that higher electricity prices in retail choice states are the result of those states' greater dependence on natural gas, rendering comparisons with rates in regulated states inapposite.[148]

144. APPA, RETAIL ELECTRIC RATES IN DEREGULATED & REGULATED STATES: A TEN YEAR COMPARISON 3 (2008) http://www.appanet.org/files/PDFs/10year.pdf [hereinafter TEN YEAR COMPARISON].

145. *See, e.g.*, SUSAN TIERNEY, ANALYSIS GROUP, DECODING DEVELOPMENTS IN TODAY'S ELECTRIC INDUSTRY-TEN POINTS IN THE PRISM 10 (2007) http://www.hks.harvard.edu/hepg/Tierney%20-%20Decoding%20Electricity%20Prices.pdf.

146. *See generally* TEN YEAR COMPARISON, *supra* note 141.

147. *Id.*

148. *Id.*

However, a comparison of electric rates and fuel prices in two areas with a similar dependence on natural gas shows that market structure makes a difference as well. The New England region is made up primarily of retail choice states and in 2007, generated 40.5 percent of power consumed from natural gas.[149] The price of natural gas affects more than just the cost of producing power at a natural gas-fired plant, because in New England, generation prices in the RTO's centralized markets are set in a single-clearing price auction, so that the highest bid accepted in each interval sets the market price for all sellers during that interval.[150] According to ISO-New England, natural gas-fired units set the market price seventy-four percent of the time in 2007.[151] Thus, the significant increase in natural gas prices beginning in 2005 has resulted in even larger increases in electricity prices.[152] Between 2004 and 2007, the price of natural gas delivered to electric generators in New England increased by nineteen percent, but average electricity prices paid by consumers increased by forty-one percent.[153]

Florida is similar to New England in its dependence on natural gas and oil. While generation in New England was 40.5 percent from natural gas and 4.4 percent from oil in 2007, Florida's dependence on these rising-cost fossil fuels was even greater, with 44.5 percent of generation from natural gas and 6.9 percent from oil.[154] However, despite a forty-three percent increase in the price of natural gas delivered to Florida's electric generators between 2004 and 2007, Florida consumers' average electric rates increased by only twenty-six percent.[155] The following chart shows that average electricity prices in New England rose much more than the delivered prices of natural gas – both as expressed in dollars and in percents. Just the opposite was true in Florida: average electricity prices rose less than natural gas prices. In fact, electricity prices in Florida increased less than they did in New England, despite Florida's much greater increase in natural gas prices.

149. *See generally* EIA, NATURAL GAS PRICES, http://tonto.eia.dov.gov/dnav/ng/ng_pri_sum_dcu_nus_m.htm (last visited Sept. 30, 2008) [hereinafter NATURAL GAS PRICES].

150. *Id.*

151. ISO NEW ENGLAND, INC., 2007 ANNUAL MARKETS REPORT 5 (2008) http://www.iso-ne.com/markets/mkt_anlys_rpts/annl_mkt_rpts/2007/amr07_final_20080606.pdf.

152. NATURAL GAS PRICES, *supra* note 149.

153. *Id.*

154. *Id.*

155. *Id.*

Increases in Natural Gas and Electricity Prices, New England and Florida
Source: Energy Information Administration data series.

	2004	2007	Difference	Percent Increase
New England				
Average Price of Electricity Paid by Consumers (in $ per MWH)	10.61	14.91	4.30	41%
Average Price of Natural Gas Deliveries to Electric Utilities (in $ per million Btu)	6.54	7.78	1.24	19%
Florida				
Average Price of Electricity Paid by Consumers (in $ per MWH)	8.16	10.30	2.14	26%
Average Price of Natural Gas Deliveries to Electric Utilities (in $ per million Btu)	6.29	8.98	2.69	43%

We believe these data show that market structure has contributed to the retail prices in RTO regions, and that the rate differentials observed are not due simply to higher fuel prices or different fuel mixes.

h. What We Conclude From the EMRI Studies

In our view, the EMRI Studies[156] have produced a sufficient body of evidence to support close scrutiny and reform of RTO-run wholesale electric markets. They contain facts pointing to substantial market dysfunction, implying that the RTO-run centralized markets regulated by the FERC may resemble more of an oligopoly than a competitive market.[157] Bodmer's research

156. A summary of the initial studies that the APPA commissioned can be found at: http://www.appanet.org/files/PDFs/EMRISummarybooklet.pdf. For the full studies, go to http://www.appanet.org/emri.cfm.

157. Electric power markets display a substantial amount of seller concentration, raising substantial questions about the ability of competitive forces to discipline price. KWOKA RESTRUCTURING SURVEY, *supra* note 86, at 73-74:

> Concern over market power is underscored by studies both of concentration in generation markets and of prices in various regions. FERC's *2004 State of the Markets Report* finds that the largest 10 generation companies now account for anywhere from 74 to 83 percent of generation in all regional markets but California and the Midwest [citation omitted]. Moreover, an increasing proportion of generation in these regional markets has been acquired by a small number of national generation companies [citation omitted]. Rising concentration is paradoxical, since fostering competition in generation was the central purpose of restructuring. With such competition in jeopardy, the very promise of restructuring lies in doubt.

Mount in his study comes to a similar conclusion: "The important conclusion from this research," regarding market participant behavior in centralized power markets, "is that electricity markets are more vulnerable than a typical commodity market to exploitation by market power. Twenty firms in a market," the number of firms Mount argues is required to ensure adequate competition in centralized RTO-run markets, "is a much bigger number than the established screening rules used by the FERC and the U.S. Department of Justice to determine that a market is competitive." MOUNT STUDY, *supra* note 108, at 17. Synapse in its LMP Study raises similar concerns about the electric market's structural features:

> In recognition of the fact that perfectly competitive markets do not exist in the real world, economists developed the concept of 'workably competitive markets', which approximate these attributes.

documents the supra-competitive profits being earned by certain sellers in RTO-run centralized markets, profits that do not seem to be restrained by competitive market forces, or the market mitigation regimes administered by RTOs' market monitors.[158] The LEI and Synapse 2007 Studies suggest generator offer patterns and behaviors inconsistent with a competitive market and consistent with the exercise of market power: large and fluctuating disparities between costs and prices, aberrational patterns of offers to sell power, and the absence of effective price signaling for the construction of sorely needed new generation and transmission facilities.[159] Rose's research shows that fuel prices alone cannot explain away the rate disparities and increases, as RTO market advocates have claimed.[160] McCullough and Stewart's and the APPA's own rate analyses point to substantial and increasing rate disparities between restructured regions and those that continue to employ traditional cost-of-service regulation.[161] These facts, when taken together, are hard to ignore.

In our view, arguments about whether one supports or opposes "competition" are beside the point. The real issue is whether there are in fact sufficient competitive forces present in RTO-run centralized markets to presume they produce just and reasonable rates. We believe that the studies cited above raise serious questions as to whether "market forces" and RTO market power mitigation regimes are sufficient to discipline prices and ensure adequate wholesale electric supplies in RTO regions. We think they must be supplemented with meaningful and adroit regulation. These problems need to be addressed before the lack of affordable retail electric service becomes even more of a threat to the quality of life and the economy of much of the nation. As the electric utility industry implements carbon-reduction measures to address climate

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> However, these prerequisites are largely absent in electricity markets. Short-term demand is notoriously inelastic; barriers to entry for new generation are high; supplier concentration during certain times and in certain regions is high; information transparency is minimal; and market players, both generators and load, exhibit myopia much more frequently than foresight.

SYNAPSE LMP STUDY,supra note 40, at 57. Synapse believes that these features indicate the potential for market power exercise:

> The summary HHI and Lerner Index metrics in Table 4.1 through Table 4.3 indicate that in PJM, the results of the spot energy market performance deviate from competitive levels, and that both PJM and in parts of the MISO region, concentration indicators show the potential for exercise of market power.

Id. at 64. Others have also observed the tendency of electric power markets towards high concentration. *See, e.g.*, ROSE & MEEUSEN, *supra* note 4, at 6 ("the structure that is emerging more closely resembles that of an oligopoly, where there are only a few firms supplying all or most of the output, than a truly competitive marketplace").

158. While market monitors have authorities to mitigate market prices to counter the impact of market power exercise, and do exercise them, they cannot make an uncompetitive market structure competitive.

159. *See generally* discussion of SYNAPSE LMP STUDY, *supra* note 40; LEI STUDY, *supra* note 106. Again, these phenomena were observed despite the market mitigation regimes implemented by RTO market monitors.

160. *See generally* discussion of ROSE STUDY, *supra* note 117.

161. *See generally* MCCULLOUGH & STEWART, *supra* note 121; APPA TEN YEAR COMPARISON, *supra* note 141.

change concerns, and as needed new transmission and generation infrastructure additions come on line to meet increasing demand, the financial burdens on retail electric customers will undoubtedly increase. State and federal policymakers owe it to these customers to make sure that rate increases required to implement these measures are not layered on top of already unjust and unreasonable rates set by dysfunctional RTO markets.

IV. THE FERC'S RESPONSIBILITY UNDER THE FPA TO ENSURE JUST AND REASONABLE WHOLESALE POWER RATES

During the early years of the utility industry, concerns about utilities' exercise of their market power to exploit consumers led to the enactment of federal and state statutes requiring that utility rates meet a "just and reasonable" standard.[162] This standard as it relates to federally-regulated "sales for resale" of electric power (what are commonly called "wholesale" sales) is set out in the FPA, which Congress has entrusted the FERC to enforce.[163]

The FERC's core responsibility under the FPA is to "guard the consumer from exploitation by non-competitive electric power companies."[164] Its primary statutory tools to protect consumers are FPA sections 205 and 206.[165] These sections require FERC-regulated "public utilities" to charge rates that are "just and reasonable."[166] In reviewing public utilities' rates for wholesale sales under this standard, the FERC must balance competing interests: it must ensure that investors in the public utility receive a fair return on their investment while, at the same time, protecting consumers from excessive rates.[167] But, FPA sections 205 and 206 are not the FERC's only statutory tools. Apart from providing the FERC with extensive investigative and adjudicatory authority,[168] Congress in FPA section 309[169] also gave the FERC the broad power "to perform any and all acts, and to prescribe, issue, make, amend, and rescind such orders, rules, and regulations as it may find necessary or appropriate to carry out the provisions of this [Act]."[170] Finally, Congress in the Energy Policy Act of 2005 granted the

162. FRED BOSSELMAN ET AL., ENERGY, ECONOMICS & THE ENVIRONMENT: CASES & MATERIALS, 506, 508-518 (Foundation Press 2000) [hereinafter BOSSELMAN] ("Although the process varies from state to state and in different contexts at the federal level, most public utility regulation imposes the following general requirements . . . Price Regulation: The regulatory body will allow the utility to charge only 'just and reasonable' rates to customers").

163. Federal Power Act of 1935, Pub. L. No. 333, 40 Stat. 803 (1935).

164. NAACP v. FPC, 520 F.2d 432, 438 (D.C. Cir. 1975), *aff'd*, 425 U.S. 662 (1976).

165. 16 U.S.C. §§ 825d, 825e (2006).

166. BOSSELMAN, *supra* note 162, at 506.

167. Public Util. District No. 1 of Snohomish County, Wash. v. FERC, 471 F.3d 1053, 1058 (9th Cir. 2006).

168. *See generally* FPA § 304, 16 U.S.C. § 825c (authorization to impose general reporting requirements); FPA § 306, 16 U.S.C. § 825e (authorization to investigate complaints), FPA § 307, 16 U.S.C. § 825f (authorization to investigate violations or potential violations of the Federal Power Act, subpoena witnesses, take evidence, and compel the production of documents); FPA § 308, 16 U.S.C. § 825g (authorization to conduct hearings); FPA § 309, 16 U.S.C. § 825h (authorization to issue, amend, and rescind orders, rules, and regulations); FPA § 311, 16 U.S.C. § 825j (authorization to conduct investigations for the purpose of recommending legislation).

169. 16 U.S.C. § 825h.

170. *Id.*

FERC new authorities to remedy manipulation of wholesale electric power sales, by adding new section 222 to the FPA.[171]

The FPA has long been interpreted to require reliable service at the lowest reasonable cost. Indeed, one of the purposes included in the text of the FPA itself is "the purpose of assuring an abundant supply of electric energy throughout the United States *with the greatest possible economy and with regard to the proper utilization and conservation of natural resources*."[172] The FERC has also expressly found that RTOs are supposed to be providing reliable service at the lowest reasonable cost.[173] Although the statute does not stipulate what method should be used to achieve just and reasonable rates, the FERC has, until relatively recently in its history, used traditional cost-of-service regulation to ensure rates were just and reasonable.[174] Its shift in recent years towards the use of markets and competitive forces to ensure just and reasonable rates, while not prohibited by the FPA as a *method*, must be shown to achieve the required results. Having decided as a policy matter to allow alleged competitive forces to discipline wholesale power rates, the FERC must take on the heavy burden of ensuring that public utility sellers in fact still charge only just and reasonable rates.[175] While "contrasting or changing characteristics"[176] within the electric industry may justify "tak[ing] a new approach to the determination of 'just and reasonable rates,'"[177] the FERC may not abdicate "its statutory responsibilities in favor of a method that, by its own description, guards against *only* grossly exploitative pricing practices…. The statute prohibits *more* than grossly abusive rates."[178] Where prices are set using market forces rather than relying purely upon costs, the FERC is no less "responsible for ensuring 'just and reasonable rates.'"[179] Moreover, the law is clear that the FERC's statutory duty to cure unjust or unreasonable rates is not limited to party-specific cases. That duty also extends to systemic, market-wide problems[180] such as those identified in this article.[181]

171. 16 U.S.C. § 824v (2008).

172. 16 U.S.C. § 824a(a) (emphasis added) (granting the FERC the authority to divide the country into regional districts for the voluntary interconnection and coordination of facilities for the generation, transmission, and sale of electric energy). *See also, Louisville Gas & Electric Co.,* 62 F.E.R.C. ¶ 61,016, p. 61,143 (1993) ("[o]ne of the Commission's primary regulatory goals is to ensure the lowest, reasonable cost energy to consumers, consistent with reliable service").

173. *ISO New England, Inc*., 118 F.E.R.C. ¶ 61,105, at P 21 (2007) ("ISO-NE … seeks only to provide reliable service at the lowest reasonable cost"); *PJM Interconnection, LLC*, 119 F.E.R.C. ¶ 61,063 at P 6 (2007) ("[a]s an RTO, PJM assumed responsibility to plan the regional transmission grid to meet the needs of the region as a whole, with emphasis on achieving reliable supply at the lowest reasonable cost").

174. *See, e.g.,* FERC, COST OF SERVICE RATES MANUAL, http://www.ferc.gov/industries/gas/gen-info/cost-of-service-manual.doc (last visited Sept. 30, 2008).

175. California *ex rel.* Lockyer v. FERC, 383 F. 3d 1006 (9th Cir. 2004).

176. Farmers Union Cent. Exch., Inc., v. FERC, 734 F.2d 1486 (D.C. Cir. 1984).

177. *Id.*

178. *Id.* (emphasis added). In *Farmers Union*, the court was construing a provision of the Interstate Commerce Act which, like the Federal Power Act, contains a statutory mandate requiring the FERC to ensure that oil pipeline rates, the class of FERC-regulated rates at issue in *Farmers Union*, are "just and reasonable." *Id.* at 1503-4 *quoting* 49 U.S.C. §§ 1(5), 15(1).

179. Norwood v. FERC, 202 F.3d 408, 419 (1st Cir. 2000) *quoting* 16 U.S.C. § 824d.

180. *See generally* Transmission Access Policy Study Group v. FERC, 225 F.3d 667, 684 (D.C. Cir. 2000) (upholding the FERC's orders imposing market-wide remedy of open access for a "fundamental

The APPA in Consumers in Peril explained the implications of this legal framework for electricity markets, given their structural features:

> In an effectively competitive market, where neither buyers nor sellers have significant market power, the commission can rationally assume that the terms of their voluntary exchanges are reasonable, and specifically infer that the sales prices are close to marginal cost, so that a seller makes only a normal return on its investment. [Footnote omitted.] (A normal return is that which is sufficient to attract adequate levels of capital financing, and not a level that earns supra-normal profits.) But, as explained above, the structural features of the wholesale electric power industry, and the resultant market power of generators, make it very difficult for competitive forces actually to discipline prices to just and reasonable levels. Moreover, research conducted for APPA in the first phase of its Electric Market Reform Initiative (undertaken in 2006) [including the LEI and Synapse 2007 Studies] shows that wholesale power prices in RTO markets bear little relationship to sellers' marginal costs of production; [footnote omitted] to the contrary, certain owners of generation are "earning supra-competitive returns that are not commensurate with returns on investments in other enterprises having corresponding risks."[182]

These generation sellers are also earning returns significantly in excess of electric utilities still subject to meaningful retail rate regulation.[183] In fact, there are significant and growing rate disparities between electric rates in regions with "restructured" markets and rates in regions that have retained traditional rate regulation.[184] All of these key indicators imply that market forces are not sufficiently restraining sellers of generation in RTO-run wholesale markets, in turn calling into question the FERC's underlying policy judgment – that RTO-run wholesale markets are "competitive," and hence sufficient to yield just and reasonable rates.[185]

These facts, taken together, led the APPA to:

> conclude that wholesale rates in RTO-run centralized markets are not just and reasonable. We believe that the FERC has the statutory responsibility to investigate this situation, and to remedy it if it finds rates to be unjust and unreasonable. As

systemic problem in the [electric] industry"); Associated Gas Distribs. v. FERC, 824 F.2d 981, 1008 (D.C. Cir. 1987) (affirming promulgation of "generic rule" that mitigated "adverse effects" on the interstate gas market) (quoting Wisconsin Gas Co. v. FERC, 770 F.2d 1144 (D.C. Cir. 1985).

181. Some have argued that the FERC's legal authority over RTOs is limited by a 2004 opinion of the United States Court of Appeals for the District of Columbia Circuit dealing with the governance structure of the California Independent System Operator (CAISO). CAISO v. FERC, 372 F.3d 395 (D.C. Cir. 2004) (vacating and remanding the FERC's order directing the California ISO to replace its governing board). Properly read, however, *CAISO* does not undermine or limit the FERC's authority to ensure the justness and reasonableness of RTO rates, terms and conditions of service. *CAISO* distinguished the D.C. Circuit's (and, later, the Supreme Court's) affirmation of Order No. 888 on grounds that the FERC's order in that case "involved FERC's authority to regulate the 'rates' that utilities were charging." *Id.* at 402. By this distinction, the D.C. Circuit reinforced the FERC's authority and responsibility to ensure that rates, terms and conditions of the FERC-jurisdictional "public utilities" – including RTOs – are just, reasonable and not unduly discriminatory.

182. CONSUMERS IN PERIL, *supra* note 5, at 10-11.

183. BODMER, *supra* note 100.

184. MCCULLOUGH & STEWART, *supra* note 121; APPA TEN YEAR COMPARISON, *supra* note 141. Note that this is the case despite the operation of RTO market mitigation regimes, since retail rates in "deregulated" regions served by RTOs include results of such mitigation.

185. MCCULLOUGH & STEWART, *supra* note 121.

> the FERC's Chairman Joseph Kelliher himself has pointed out, "[t]he legal duty of the Commission to prevent unjust and unreasonable rates and undue discrimination or preference in the sale of wholesale power or interstate transmission by jurisdictional sellers is absolute; the Commission does not have the discretion to ignore them."[186]

We reach the same conclusion.

The FERC in 2007 opened a docket to review the operation of RTO wholesale power supply markets, issuing its Advance Notice of Proposed Rulemaking (ANOPR) on June 22, 2007.[187] In comments on the ANOPR, the APPA and many other commenters representing load-side interests, delineated in detail their substantial concerns with RTO markets.[188] Nonetheless, the FERC in

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186. CONSUMERS IN PERIL, *supra* note 5, at 11 (quoting Joseph T. Kelliher, *Market Manipulation, Market Power, and the Authority of the Federal Energy Regulatory Commission*, 26 ENERGY L.J. 1, 3–4 (2005)).

187. Advance Notice of Proposed Rulemaking, *Wholesale Competition in Regions with Organized Electric Markets*, F.E.R.C. STAT & REGS. ¶ 32,617, 72 Fed. Reg. 36,276 (2007).

188.

> A broad range of load-side interests and consumer-side advocacy groups commented in their Fall 2007 comments on the ANOPR regarding problems in the RTO-run markets, calling for fundamental market reforms. [The 2007 comments referenced below are available through the FERC's website under Dockets RM07-19 and AD07-7 at http://elibrary.ferc.gov/idmws/search/fercadvsearch.asp.] *See, e.g.*, Comments of the Electricity Consumers Resource Council, American Iron and Steel Institute and American Chemistry Council (collectively 'Industrial Customers') at 29 ('Industrial Customers believe that as currently designed the organized [*e.g.*, RTO] markets are permanently structured as sellers' markets.') and 3 ('…fundamental changes to the Day-Two market paradigm will be necessary to establish a robust forward market capable of delivering net benefits to consumers.'); Comments of Portland Cement Association (filed August 17, 2007), at 3 ('It is the hope of PCA that this Commission will seriously consider the impact of prior Commission decisions on electricity consumers and address some of the basic market design deficiencies that currently exist and cause the current system to effectively impose a tax on electricity consumers for the benefit of the shareholders and management of electricity generation companies.'); Comments of the National Rural Electric Cooperative Association at 21 (footnote omitted) ('The greater problem is the lack of sufficient entry in organized markets. Entry is too slow and uncertain to drive the price for long-term resources down towards the cost of the resources. The opportunity for low-cost base-load resources to benefit from the dark spread in the organized spot markets is too valuable for the owners of those resources to enter into long-term contracts reflective of the cost of those resources themselves.'); Comments of the American Forest and Paper Association at 3 ('We remain concerned that levels of market concentration, instability in fuel cost relationships and a suboptimal resource mix all pose special and difficult challenges that may call into question the appropriateness of the current market design as a means of meeting the demand of fundamental fairness that underlies the just and reasonable rate standard.'); Coalition of Midwest Transmission Customers, NEPOOL Industrial Customer Coalition, and PJM Industrial Customer Coalition Comments at 34 ('[We] urge the Commission to tackle market design, structural market power, and energy deliverability issues as soon as possible. Unless the Commission addresses these threshold issues, organized electric markets will remain in an increasingly familiar vicious cycle of 'locational/granular pricing leading to market power leading to market power mitigation leading to revenue backfills' that has come to characterize organized electric markets in the Northeast and appears to be spreading westward.'); Comments of Steel Producers [Nucor and Steel Dynamics] at 1–2 ('After ten years of experience with RTOs and organized wholesale electricity markets, it is evident that the organized markets have not yet delivered the promised benefits to retail electric customers. Prices remain stubbornly high, and opportunities for retail customers to control their electricity costs are limited. Meanwhile, there seems to be little incentive on the part of utilities and suppliers to take the steps needed to improve the operation of the markets, including building new transmission, fully integrating demand response into the markets, and building or acquiring lower-cost generation capacity.'); and Comments of Indianapolis Power and Light Company (IPL) at 2 ('IPL implores the Commission to focus its efforts on ensuring that RTOs and ISOs are a means to bring

both its ANOPR and its subsequent Notice of Proposed Rulemaking issued in those same dockets on February 22, 2008,[189] declined to commence an investigation into the justness and reasonableness of rates produced in RTO-run centralized markets.[190] In its NOPR, the FERC "acknowledges the concerns"[191] that these parties raised in their comments regarding the overall justness and reasonableness of rates in RTO markets, but denied requests to open a broader investigation into this issue.[192] According to the FERC, these parties failed to "offer any specific solutions"[193] or "appreciate the differences in market design that exist in each region."[194] Instead, the FERC directed "each RTO or ISO to provide a forum for affected customers to voice specific concerns (and to propose regional solutions) to the issues raised generically by APPA and AARP, *et al.*"[195]

> value to consumers in the form of lower prices and reliable service, and avoid focusing on theoretical benefits. The goal is not markets for markets sake, but the same goal as has always been the case—reliable service at reasonable rates. This goal has somehow been lost in the overall RTO/ISO debate').

COMMENTS OF THE APPA, WHOLESALE COMPETITION IN REGIONS WITH ORGANIZED ELECTRIC MARKETS 16 n.6, http://www.appanet.org/files/PDFs/APPACommentsRM071942108asfiled.pdf (last visited Oct. 3, 2008).

189. Notice of Proposed Rulemaking, *Wholesale Competition in Regions with Organized Electric Markets*, F.E.R.C. STATS & REGS. ¶ 32,628, 73 Fed. Reg. 12,576 (2008) [hereinafter NOPR].

190. *Id.* at P 17.

191. *Id.*

192. *Id.*

193. *Id.* at P 18.

194. *Id.* at PP 17-18. FPA section 206 by its own terms does not require third parties seeking to have the FERC institute a section 206 investigation to provide a "solution" to the alleged unjust rates and charges as a precondition to the initiation of an investigation. Rather, the FERC is charged under section 206(a) to conduct a hearing to determine whether unjust and unreasonable rates are in fact being charged for wholesale sales of electric power, and if so, to "determine the just and reasonable rate, charge classification, rule, regulation, practice or contract to be thereafter observed and in force," and to "fix the same by order." 16 U.S.C. § 824e(a).

195. NOPR, *supra* note 189, at P 24. Such a response to claims of unjust and unreasonable RTO rates is unorthodox, to say the least. RTOs are regulated "public utilities" subject to the FERC's FPA Section 205 and 206 jurisdiction. The FERC cannot refer claims that public utilities are charging unjust and unreasonable rates to the very public utilities operating the markets producing the rates that are being charged. Sierra Club v. Sigler, 695 F.2d 957, 963 n.3 (5th Cir. 1983) ("an agency may not delegate its public duties to private entities, particularly private entities whose objectivity may be questioned on grounds of conflict of interest") (citation omitted); Perot v. FEC, 97 F.3d 553, 559 (D.C. Cir. 1996) (acknowledging, as a general proposition, that "when Congress has specifically vested an agency with the authority to administer a statute, it may not shift that responsibility to a private actor"); *see also,* Carter v. Carter Coal Co., 298 U.S. 238, 311 (1936) (ruling that the delegation of authority to set hours and wages to a private coalition of coal producers and employees constitutes delegation "in its most obnoxious form; for it is not even delegation to an official or an official body, presumptively disinterested, but to private persons whose interests may be and often are adverse to the interests of others in the same business."); U.S. Telecom Ass'n v. FCC, 359 F.3d 554, 567-68 (D.C. Cir. 2004) (stating that "the general conferral of regulatory authority does not empower an agency to subdelegate to outside parties;" while agencies may rely on outside parties to furnish factual information or provide advice and policy recommendations, agencies may not allow outside parties to make "crucial decisions" regarding fundamental policy questions, particularly where agency oversight is "neither timely nor assured," and "may not…merely 'rubber-stamp decisions' made by others under the guise of seeking their 'advice' . . . nor will vague or inadequate assertions of final reviewing authority save an unlawful []delegation.") *Id.* (citations omitted).

The FERC's decision not to investigate these matters, but instead to refer claims of unjust and unreasonable RTO rates back to the RTOs themselves, could have substantial negative policy repercussions. Given the growing concerns that RTO-run centralized markets are not producing just and reasonable rates,[196] and the increasing turmoil in states with retail restructuring regimes,[197] federal and state energy regulators and legislators eventually may have no choice but to undertake a broader examination of the problems with these centralized wholesale markets.

The RTOs themselves and the merchant generators participating in RTO-run centralized markets assert that electric consumers are benefiting from "competition."[198] To the contrary, we believe that RTO-run markets are not sufficiently competitive to ensure just and reasonable rates. These "markets" are essentially administratively developed constructs featuring centralized repeated auctions, in which sellers can quickly learn the strategies of other bidders and adjust their own bids accordingly.[199] Rhetoric about competitive markets cannot cover up the increasing shortfall of new generation capacity required to ensure adequate electricity supplies in future years, at the same time that billions of dollars are simply leaving the market in the form of profits to shareholders of unregulated, often incumbent generators owning "legacy" plants built under and

196. While load-side interests have been concerned for some time with high RTO rates, complainants joining in the May 30, 2008 complaint against PJM in Docket No. EL08-67-000 regarding the outcomes of its first four "transitional" RPM auctions included the state commissions of Maryland, Delaware, New Jersey, and Pennsylvania, as well as the consumer advocate offices for the states of New Jersey, Pennsylvania, Maryland, Ohio, and the District of Columbia. Customer complainants included the United States Department of Defense and other affected Executive Agencies. MPSC Complaint, *supra* note 46.

197. Examples include: the recent litigation between Constellation and Maryland, which has now settled; S.B. 221, 127th Gen. Assem., Reg. Sess. (Ohio 2007) (enacted) (revamping Ohio's retail access regime); the recent legislation modifying Michigan's retail electric restructuring regime; Act No. 286, Enrolled House Bill No. 5524 (effective October 6, 2008), http://www.legislature.mi.gov/(S(ylmeodi2p2xpai55li0o4puy))/documents/2007-2008/publicact/pdf/2008-PA-0286.pdf; attempts in Pennsylvania by the state legislature to extend the current rate caps for certain Pennsylvania electric utilities, HOUSE ENVTL. RES. & ENERGY COMM., HEARING SCHEDULED ON BILL THAT WOULD EXTEND UTILITY RATE CAPS (2008), http://www.pahouse.com/PR/074032008.asp; and the debate and legislation in Illinois resulting in a refund and creation of the Illinois Power Authority, CITIZENS UTILITY BOARD, ELECTRIC REFORM & COMED CUSTOMERS (2007), http://www.citizensutilityboard.org/pdfs/ConsumerInfo/20070910_ComEdElectricPackage.pdf.

198. ELCON, TODAY'S ORGANIZED MARKETS-A STEP TOWARD COMPETITION OR AN EXERCISE IN RE-REGULATION? (2006), http://www.elcon.org/Documents/Publications/12-4piom.pdf.

199. Blumsack, *supra* note 28, at 176; *see also* SETH A. BLUMSACK ET AL., CARNEGIE MELLON ELEC. INDUS. CTR., COMMENTS ON WHOLESALE & RETAIL ELEC. COMPETITION (2005), http://wpweb2.tepper.cmu.edu/ceic/pdfs_other/FERC_Comments_11_18_05.pdf (discussing how the hourly market structure "has had the unintended consequence of fostering tacit collusion among generators bidding into the auction" and explaining how generators who interact often with the same group of other generators in a market setting can quickly learn the strategies of other bidders); ROSE & MEEUSEN, *supra* note 4, at 71-72:

> Coordinated interaction and tacit collusion among suppliers could also have particular relevance for electricity markets. The nearly continuous interaction that suppliers have in Regional Transmission Organization (RTO) markets can allow firms to exercise market power and utilize anti-competitive bidding strategies. While transparency is important for markets to perform well, it can have the unintended [consequence] of creating markets that facilitate collusive supplier behavior. A lack of publicly available information impairs the ability to more fully assess market behavior.

paid for under cost-of-service regulation.[200] At the same time, other new entrants have at times earned insufficient revenues to cover their costs.[201] Failure to take appropriate corrective actions to fix these systemic problems will not only leave consumers to pay unjust and unreasonable rates, but could also eventually lead to inadequate transmission and generation capacity that would undermine the electrical reliability of entire regions of the country.

V. A REFORM PROPOSAL – RESTRUCTURE DAY TWO RTOS AS "DAY 1.5" RTOS

As discussed above, the FERC, in its NOPR, criticized commenters seeking a broader investigation into the justness and reasonableness of rates produced by RTO-run centralized wholesale power markets for not having proposed "solutions," *i.e.*, specific proposals for RTO market reforms.[202] While two RTO market reform proposals were in fact offered by commenters on the NOPR, neither appears to have, as yet, persuaded the FERC to undertake such an investigation.[203] To contribute another possible policy option to the ongoing debate about "solutions" for RTO market problems, we suggest in this article that the FERC consider streamlining the full "Day-Two" RTOs to trim back many of the problematic market features and strengthen the RTOs' focus on their transmission functions. Because we recognize that a return to a "pure" Day-One structure would entail high transition costs and the potential disruption of many commercial arrangements, we are instead recommending a hybrid approach that we have dubbed a "Day 1.5" RTO structure. Such an approach would maintain most of the demonstrated consumer and economic benefits of RTOs, which we believe are in the "Day-One" transmission-related functions, while moving most power supply transactions out of RTO-run centralized bid-based markets, in favor of a stronger bilateral contracting regime. Thus, this proposal is intended

200. BODMER, *supra* note 100, at 8-18.

201. *Id.* at 19. Bodmer also reviewed the profitability of the generators selling into PJM that had not been able to leverage legacy ratepayer financing of generation assets. He found their financial performance was uneven, and in some periods was "dismal." He noted that their volatile performance had increased required returns for new equity investment in generating plants, making underwriting requirements more stringent. This in turn has increased the cost of new generator entry into RTO-run centralized markets.

202. F.E.R.C. Stats. & Regs. ¶32,628 at P 11.

203. *NOPR*, *supra* note 189 (Comments of Am. Forest & Paper Assoc.) [hereinafter AF&PA]; *NOPR*, *supra* note 190 (Comments of Portland Cement Assoc.*)* In its NOPR, the *FERC* noted that these two latter proposals did "warrant additional consideration," and directed its Staff to convene a technical conference to consider them. AF&PA, *supra* note 190, at P 25; Supplemental Notice of Technical Conference, *Capacity Markets in Regions With Organized Electric Markets ISO New England*, 73 Fed. Reg. 24,490 (2008). As of this writing, the FERC has taken no further action with regard to either of these two proposals. Both of them attempt to address certain shortcomings of locational capacity markets by more closely linking the revenues that participating generators earn from an RTO's capacity markets with, and from, the RTO's energy and ancillary services (E&AS) markets. The AF&PA proposal would do this through the use of a "strike price" for E&AS sales. The PCA proposal is more sweeping, however, in that it would place the RTO in position of entering into long-term contractual obligations to capacity sellers on behalf of the RTO's customers. The transcript of the technical conference is available on the FERC's website, (www.ferc.gov) through its E-library as Issuance No. 20080507-4024(19248082). *See generally* Transcript at 44-54 (Statement of Don Sipe for AF&PA), and 79-89 (Statement of Paul Williams for PCA). Moreover, , a third RTO market reform proposal was suggested in LESTER LAVE ET AL., CARNEGIE MELLON ELEC. INDUS. CTR., DEREGULATION/RESTRUCTURING – WHERE SHOULD WE GO FROM HERE? (2007), http://wpweb2.tepper.cmu.edu/ceic/papers/ceic-07-07.asp.

to keep what is working relatively well in RTOs, while revamping or removing altogether those functions and features, mostly associated with RTO-run centralized energy, ancillary services and locational capacity markets, that we believe are of questionable benefit to consumers.

A. Overview of Proposed Day 1.5 Model

The general functions that such a Day 1.5 RTO would carry out include the following:

- Ensuring non-discriminatory access to the grid through independent administration of an OATT and provision of transmission service,[204] including needed ancillary services (discussed further below). Demand-side resources would participate in these markets, if they met the necessary technical criteria.
- Developing and administering a regional transmission rate design that eliminates rate pancaking and supports the construction and associated cost recovery of transmission facilities owned by all transmission owners and providers that wish to participate in the RTO, regardless of their form of ownership.
- Operating a single regional Open Access Same-time Information System (OASIS) and independently calculating Available Transfer Capability (ATC).
- Conducting independent and collaborative regional transmission and generation interconnection facilities planning, with the input of affected stakeholders, including state authorities, thus building the regional support required to obtain siting authority for needed new transmission facilities and upgrades. Such planning processes should consider the ability of demand response, energy efficiency, and distributed generation resources to reduce the need for new central station generation and associated transmission facilities.

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204. An important question is whether implementation of a Day 1.5 RTO would include a return to a physical transmission rights regime, and if so, how such a transition would be accomplished. It may be difficult to provide non-pancaked, non-discriminatory transmission service under a physical transmission rights regime (at least without a substantial transition period), given that RTOs during their move to Day Two markets generally allocated or auctioned source-to-sink FTRs employing the full capacity of the transmission system to accommodate the requested source and sink pairings, under a "simultaneous feasibility" criterion. Having effectively parceled out the "firm" system capacity in the form of financial transmission rights, it might be difficult also to honor firm physical transmission rights without adversely affecting the financial viability of the previously allotted FTRs. On the other hand, physical rights and financial rights co-existed for a substantial period of time during the MISO's transition to a financial rights regime (during which time transmission agreements carrying physical rights were "grandfathered"). *See, e.g., Midwest Independent Transmission System Operator, Inc.*, 108 F.E.R.C. ¶ 61,236 (2004) (the FERC divided grandfathered transmission agreements into several categories, with differing consequences for their treatment in MISO's energy and FTR markets; among other things, the FERC required MISO to carve certain of the grandfathered agreements out of its markets and accepted MISO's proposed tariff sheets that described the prospective treatment of grandfathered agreements). CAISO still has many grandfathered "existing contracts" that are insulated against congestion charges with so-called "perfect hedge" – a means of establishing a dual congestion management/physical rights regime. Hence, it is not unimaginable that a "reverse-grandfathering" regime could be developed to facilitate a return to physical rights over a period of years. The Day 1.5 market design proposal presented in this article could potentially work with either a physical rights or financial rights transmission service regime.

- Carrying out "wide-area" system security and reliability-related activities, ensuring that transmission facilities are operated in compliance with relevant North American Electric Reliability Corporation (NERC) and regional reliability entity criteria.
- Operating an optimization market to enable transmission customers to manage their imbalances, purchase economy energy and ancillary services, and to allow generators (including intermittent renewable generators) to sell excess generation not committed under bilateral contract arrangements. The features of such a market, including the proposed requirement that generators' offers into this market be based on their marginal costs of production, are discussed further in the next section.
- Ensuring adequate and economic generation reserves (and concomitant revenues to generators) through implementation of resource adequacy requirements. Individual LSEs, including both incumbent utilities and retail access suppliers, would have to meet these requirements through development of appropriate power supply and capacity portfolios, including demand-side resources. State public utility commissions in each RTO region would assist in development of and approve these requirements for all utilities and other entities they regulate at the retail level, assuring that these supply portfolios are economic in the broadest sense, considering not only price alone, but fuel diversity and other relevant policy concerns. The features of such a resource adequacy requirement regime, including the ability of generators to make market-based rate offers, are also discussed further in the next section.
- Carrying out additional functions (*e.g.*, operation of a power pool) if all classes of stakeholders in the region agree on the need for such functions, and the RTO can justify them as beneficial to ultimate consumers through thorough and unbiased cost-benefit analyses.

With an RTO's operations focused on these functions, the following features of Day Two markets would be phased out over time:

- *Centralized bid-based locational capacity markets*. Capacity would be provided for through bilateral contracts entered into to comply with resource adequacy requirements. Demand response and energy efficiency resources would be included in LSEs' portfolios to assist in fulfilling resource adequacy requirements.
- *Initial FTR allocations/auctions for non-market participants*. FTRs/LTTRs would be allocated to LSEs, who could make their own individual choices about whether or not to retain these rights or to sell them in a secondary market.
- *Use of market-rate bid-based DA and RT markets and the resulting supra-competitive profits*. Generator offers to sell energy into the optimization market would be based on costs previously filed with the RTO's market monitoring function. Bilateral contracts generally would not be cost-regulated and would cover the bulk of volumes and transactions.

- *Generator opportunities for withholding*. Must-offer requirements would be imposed on generators, with proper allowances for scheduled and emergency outages, time-limited resources, and intermittent resources.

We believe that RTO market reform proposals (be they ours or others') need to reduce the attractiveness of short-term energy markets to generation sellers, and incent both sellers and buyers to move towards a long-term contracting regime that would better support new generation and transmission investment. Pairing such a regime with a resource adequacy requirement that requires LSEs to develop a balanced portfolio of resources for a substantial forward period would be required to prevent buyers from taking advantage of reformed short-term energy markets, to the detriment of generators. Finally, restoring the ability of utility LSEs to compete, subject to appropriate safeguards, with third-party generators to supply the required forward resources will hopefully increase overall competition to supply power in the forward market, driving power supply costs down to the long run cost of an LSE's diversified portfolio of mid-term generation, long-term generation and demand response resources. We set out below some possible features of such a reformed short-term optimization market regime, coupled with an enhanced resource adequacy requirement.

B. Possible Features of Reformed Energy and Ancillary Services Markets

Generation sellers submitting bids into an RTO's short-term optimization market would have to pre-submit relevant cost information for each generation unit in their portfolios to the RTO's market monitoring function to be eligible to make subsequent bids to sell energy or ancillary services from such units.[205] While generators would no doubt argue that such data should be kept confidential, we favor full disclosure of such market-related data, absent extraordinary circumstances.[206] Subsequent energy and ancillary service bids that generation sellers submitted would have to comport with the cost data previously provided, or they would have to submit an explanation of changed circumstances to the market monitoring function at the time of the bid.

To spur generation seller participation in forward bilateral contract markets at just and reasonable prices, their offers in the optimization (energy and ancillary services) market would have to be based on the short-run marginal

205. Many generators currently disclose their cost information to RTO MMUs, but do so on a confidential basis.

206. DUNN STUDY, *supra* note 134, at 14 (recommending that unmasked RTO electricity market offer and bid data should be released on the day after the operating day, and that unmasked physical operating characteristics of generation resources should be publicly available); MCCULLOUGH & STEWART, *supra* note 122 (arguing that RTOs should file with the FERC their system lambdas (the variable cost of the last kilowatt produced over a particular hour) to allow analysis of the extent to which RTO hourly real-time prices are higher than marginal costs); Howard M. Spinner, *Pondering PJM's Energy Price Run-up: Does Inappropriate Market Power Explain the Increase During 2005?*, PUBLIC UTILITIES FORTNIGHTLY, June 2006, 74-79, http://www.fortnightly.com/pubs/06012006_PONDERING.pdf (Author used publicly-available information to study price increases in PJM energy markets and found that price increases were not fully explained by higher loads and higher commodity fuel price, and noting that PJM does not release the heat rates of the marginal units).

costs of operating their units, consistent with their previously-submitted costs of service.[207] This is consistent with the theory that sellers should be recovering their fixed costs (including return) through long-term bilateral contract arrangements, and not relying on short-term RTO market sales to recover such costs.[208] Cost-based, short-term, energy markets would also reduce the opportunity for supra-competitive prices and opportunities for the exercise of market power discussed in earlier sections of this article.[209]

One of the knottiest RTO market design problems is how to design ancillary service markets and integrate them with short-term energy markets. Even when RTOs operate their DA and RT energy markets using market-based rates, the structural features of certain ancillary service markets (*e.g.*, regulation and reactive power) make them more problematic candidates for market-based pricing.[210] If generators are required to submit bids that comport with previously submitted costs-of-service for each unit (and to offer generation not committed under bilateral agreements to the RTO's short-term energy and ancillary services markets, as later discussed), it should be possible for the RTO to "co-optimize" bids across these markets, in effect operating one umbrella "optimization" market.[211] If a generator is chosen to provide an ancillary service such as

207. For a discussion of the elements of short run marginal cost, *see generally* SYNAPSE LMP STUDY, *supra* note 40, at 1:

> The concept of 'short-run marginal cost', which is fundamental to understanding electricity markets, is subject to some dispute. SRMC clearly includes avoidable costs such as fuel, emissions costs, and avoidable operation and maintenance costs, which are incurred in proportion to the amount of electricity the unit produces. In a classic discussion of this issue, William Vickery (1992) argues that accelerated depreciation of equipment due to wear and tear should also be included in SRMC. However, there is often some ambiguity over which depreciation costs will be accepted by market monitors as part of cost-based offers. PJM allows for bid increments for depreciation, provided that they 'represent actual expenditures that are due to incremental degradation of generating equipment directly related to generation, starts or a combination of both' [citation omitted].

208. The lack of opportunity for certain generators to recover sufficient revenues from the energy and ancillary services markets has been used to justify both locational capacity markets such as RPM and the allowance of price spikes to recover these costs. WILSON STUDY, *supra* note 67, at 5.

209. PCA has proposed an analogous approach; its alternative market design includes a combination of cost-based energy bids with market-based capacity pricing, and long-term contracts. PAUL WILLIAMS, LIBERTY ENERGY GROUP, FERC IMPLEMENTATION OF MKT. BASED WHOLESALE ELEC. RATES: A STORY OF UNFULFILLED PROMISES FOR CONSUMERS (2008), http://www.ferc.gov/EventCalendar/Files/20080507072051-Williams,%20Liberty%20Energy%20on%20behalf%20of%20Portland%20Cement.pdf.

210. *See, e.g.*, PJM MARKET REPORT VOLUME 2, *supra* note 76, at 276, 279:

> The MMU concludes from these results that the PJM Regulation Market in 2007 was characterized by structural market power in 80% of the hours.... [I]n 2007, as in 2006, the MMU cannot conclude that the Regulation Market produced competitive results or noncompetitive results, based on the MMU analysis of the relationship between the offer prices and marginal costs of units that set the price in the Regulation Market, the marginal units. The MMU's reliance on estimates of regulation costs is one of the reasons that the MMU recommends that all suppliers be required to provide cost-based regulation offers as part of real-time power mitigation.

211. Co-optimization occurs where energy and ancillary services are cleared simultaneously in the market, rather than in subsequent steps. DANIEL SADI KIRSCHEN & GORAN STRBAC, FUNDAMENTALS OF POWER SYSTEM ECONOMICS 121 (John Wiley & Sons 2004).

supplemental/spinning reserves, but is not in fact called upon to run in the relevant time interval, it should be compensated for the costs of standing ready to provide the needed reserves.

The treatment of demand response bids in the optimization markets presents additional difficult policy choices. If such bids were treated comparably to generator bids, they too would have to be cost-based, and not recover fixed costs. Such treatment, however, would likely discourage development of demand response resources. For a plethora of reasons, including the need to develop resources with low or no carbon impacts, it would make more sense from a policy standpoint to allow demand response bids to be submitted without having to first submit associated costs-of-service for each such resource. Since a demand response resource would have to clear in a short-term optimization market in which generator bids are also being evaluated and stacked in ascending cost order, a demand response resource bid in at too high a price would not clear the market. In other words, cost-based generator bids would provide price discipline for those entities making demand response bids. In addition, sufficient safeguards would have to be included in RTO tariffs to ensure that demand response resources would indeed perform as promised at the time demanded if a demand response bid clears the market. RTOs such as ISO New England are currently working on such criteria, to avoid the phenomenon of "phantom" demand response resources.[212]

Another vitally important issue to resolve in developing such a market reform proposal is whether to employ a single-clearing-price mechanism in the optimization market. Of course, there have been past debates regarding the use of a single-clearing price versus employing a "pay-as-bid" mechanism.[213] The "conventional wisdom" cited by many economists is that under a single-clearing-price regime, suppliers will bid their marginal costs, but that under a pay-as-bid system, sellers will employ bidding strategies that attempt to figure out what others will bid, and maximize their profits accordingly, making the single-clearing-price mechanism superior.[214] While the debate is certainly worth

212. *ISO New England Inc.,* 123 F.E.R.C. ¶ 61,021 at PP 49-65 (2008) (approving modifications to ISO New England's Day-Ahead Load Response Program to avoid further payments for "phantom load reductions") and partial dissent of Commissioner Wellinghoff ("[w]hether a supplier or demand response provider, market participants that do not play by the rules harm a market and deny consumers the benefits of competition"); *see also ISO New England Inc.,* 123 F.E.R.C. ¶ 61,266 (2008) (lowering the heat rate component of the Day-Ahead Load Response Program). PJM also made a tariff filing on April 14, 2008, to modify the rules applicable to its demand response program, to address concerns that some demand response providers were being paid for load reductions that would have taken place regardless of price signals in PJM's energy markets. Letter from Craig Glazer, Vice President, PJM, to Kimberly Bose, Secretary, FERC (Apr. 14, 2008), *available at* http://www.pjm.com/documents/ferc/documents/2008/20080414-er08-xxx-000.pdf. The Commission accepted PJM's filing, subject to a compliance filing requirement, on June 12, 2008. *PJM Interconnection, LLC*, 123 F.E.R.C. ¶ 61,257 (2008).

213. Blumsack, *supra* note 28 at 176.

214. *See, e.g.,* ALFRED E. KAHN ET AL., CAL. POWER EXCH., PRICING IN THE CALIFORNIA POWER EXCHANGE ELECTRICITY MARKET: SHOULD CALIFORNIA SWITCH FROM UNIFORM PRICING TO PAY-AS-BID PRICING? 17 (2001), http://www.cramton.umd.edu/papers2000-2004/kahn-cramton-porter-tabors-blue-ribbon-panel-report-to-calpx.pdf ("[i]n sum, our response is that the expectation behind the proposal to shift from uniform to as-bid pricing – that it would provide purchasers of electric power substantial relief from the soaring prices of electric power, such as they have recently experienced – is simply mistaken"); *see also* Blumsack, *supra* note 28.

having, we are here proposing the use of a single-clearing-price mechanism for the reformed optimization market, primarily to eliminate this issue as a bone of contention with generator interests and the academicians that support them. We note in this regard that locational marginal pricing was originally envisioned as a cost-based optimization algorithm for regulated, vertically-integrated utilities, rather than for use in a bid-based environment.[215] If the clearing price paid to the last seller needed to clear the optimization market during the designated time interval is indeed based on that seller's short-run marginal costs of production, and all sellers whose offers clear the market receive that price, then the economic theory underpinning the single-clearing price auction market would be honored.

Without market features requiring purchasing LSEs to maintain a portfolio of longer-term generation resources to serve their loads, the temptation for them to simply rely on the short-run marginal cost-based short-term optimization markets for a substantial portion of their power supplies could be quite high. In such an environment, the generators' claims that they were suffering "missing money" (*i.e.*, that they were not recovering their generation fixed costs) might well be justified.[216] To prevent this result, we propose to impose on LSEs a "resource adequacy" requirement to obtain sufficient longer-term generation resources to serve their anticipated loads,[217] thus preventing them from "leaning" on a short-term optimization market intended primarily as a balancing market. To do this, LSEs could be required to submit anticipated loads at specified intervals (*e.g.*, month ahead, week ahead, day ahead, hour ahead), and the schedule of generation resources they have the right to call upon to serve those loads (including both generation and demand response resources).

215. SYNAPSE LMP STUDY, *supra* note 40, at xii *quoting* SCHWEPPE ET AL., SPOT PRICING OF ELECTRICITY 111 (Kluwer Academic 1988).

216. The claim by generators that they could not recover their costs of operating more expensive peaking units from energy market revenues, and hence were suffering "missing money," was one of the main arguments in favor of implementing locational capacity markets. *See, e.g.*, Statement of Reem Fahey on behalf of Edison Mission at the February 3, 2006 Technical Conference on RPM held in *PJM Interconnection, LLC*, Docket Nos. EL05-148-000, Transcript at 84-85 (available on FERC's E-Library as Issuance 20060203-4026 in Docket No. EL05-148, filed 02/03/2006):

> Actually, if I could just spend two minutes to explain that, because people just get sort of puzzled, why isn't a new peaker making enough money in the market, and the answer is very simple. We designed the markets to be inherently long; so we designed the markets to be reserve plus 15 percent. So think about it this way: To the extent that you have mild weather, and to the extent that all the generators performed very well in the summer. No generator trips. That peaker that you need for reliability is going to run 10 hours, maybe, 10 hours in the whole year. So if that peaker is going to cover its cost—I mean, we'll do the math – they need $7,000 per megawatt-hour in all these 110 [sic] hours. Are we going to do that? No. Again, we're not going to allow prices to go that high. So I think it's the combination of these two things that inherently, because of reliability issues and because the way we've designed this market is we need to be long, it's an insurance policy. So the 15 percent and the fact that they can't recover their costs, then that missing money has to be made up somewhere; and it has to be made up in the capacity market.

217. The FERC, in March 2008, approved a Resource Adequacy proposal for MISO (Module E to MISO's OATT) that shares certain features of the authors' proposal here. *Midwest Indep. Transmission Sys. Operator, Inc.*, 122 F.E.R.C. ¶ 61,283 (2008). The authors, however, are not endorsing the specific aspects of MISO's Module E through their proposal in this article.

To prevent LSE underestimation of anticipated loads, the RTO should review LSEs' submitted estimates of anticipated loads in the light of past actual LSE demands during similar time periods, anticipated weather conditions, and other relevant factors, and require revisions if it appears the estimates are "off" in light of these factors. LSEs' projected load and resource data should be made public (as in the case of generator cost, heat rate and offer data) so that third-party scrutiny would help keep LSEs "honest" in estimating their anticipated loads.

Some flexibility in application of the resource adequacy requirement would likely be necessary to accommodate LSE use of intermittent resources. One possible approach might be to require LSEs scheduling wind power or other intermittent resources to specify other resources that could back up the intermittent resource (*e.g.*, natural gas-fired units or hydroelectric power) if anticipated resources are not in fact available during the relevant time interval. Another approach might be to allow the RTO to perform an overall review of all submitted LSE generation schedules, and to assess the aggregate scheduled intermittent and other resources over the RTO footprint to ensure that it has a sufficient diversity of generation resources to operate the system reliably.[218]

To ensure that the RTO has the necessary resources to balance supply and demand on the system, it would likely be necessary to require generators to offer into the optimization market generation resources not previously committed under bilateral agreements. Special provisions would likely be required for limited-run resources (*e.g.,* generation units subject to air quality limitations on run times, and hydroelectric units that must be operated for water use and recreational purposes as well as power supply production).[219] Of course, the possibility of a "sick day" problem (generators declaring outages because they do not wish to run) would remain even with such a must-offer requirement. This problem, however, plagues RTOs even today. The best defense is a strong market monitoring function that is well integrated with RTO system operations.

C. Possible Features of a Resource Adequacy Requirement

As noted previously, RTO-run centralized locational capacity markets have been very problematic for many LSEs and the end users they serve. We believe that it would be better to use bilateral power supply and demand resource

218. BRENDAN KIRBY & MICHAEL MILLIGAN, NAT'L RENEWABLE ENERGY LAB., FACILITATING WIND DEVELOPMENT: THE IMPORTANCE OF ELECTRIC INDUSTRY STRUCTURE (2008), http://appanet.org/files/PDFs/LEIReport2012007.pdf:

> Power system characteristics that mitigate and accommodate variability make it easier to integrate wind into grid operations. Wind-friendly physical characteristics include geographically and electrically large balancing areas, as well as generator characteristics such as fast-ramping, load-following capability. They also include market structures that provide access to conventional generation flexibility and maneuverability; the ability of a generator to ramp up and down quickly and accurately, to turn on and off quickly and at low cost, and the ability to operate at low minimum loads (citations omitted).

219. This should not be a problem for intermittent generation such as wind, given that its production varies with the availability of the wind resource, making it difficult to withhold from the market except by "spilling" of the resource.

contracts entered into by LSEs on one hand and generators and demand response providers on the other to ensure adequate supply resources in RTO regions in future years. While generator market power would obviously remain a major concern under any market design, we believe that arms-length negotiations between individual buyers and sellers are more likely to result in competitive results than centrally-designed and centrally-run administrative "market" constructs. The "repeated game" bidding strategies that can be used in such markets, such as "hockey stick" bidding and the use of economic withholding to raise the market clearing price, would not come into play in bilateral negotiations. Moreover, the requirement that generators submit cost-based offers in the optimization market and the associated must-offer requirement would give generators more incentive to contract forward in the bilateral market.To provide generators with a positive incentive to participate in bilateral forward markets, we are further proposing that those generators passing the FERC's relevant market-based rate screens[220] should be permitted to sell at market-based rates in bilateral forward markets, although they would be limited to cost-based rates in the RTO's short-term optimization market.[221] RTO MMUs should also monitor bilateral contract markets, and act on complaints regarding anticompetitive behavior by sellers or buyers in those markets.

RTO specification of the level of generation and demand response resources necessary for an LSE to meet its resource adequacy requirement is a controversial jurisdictional issue. State public utility commissions take a strong interest in such issues, even in states where retail access has been implemented by state legislation or regulatory policy. Many retail access states have imposed Provider of Last Resort (POLR) type-obligations on their incumbent utilities.[222] Some have mandated state power procurement regimes for such service (often

220. Order No. 697, *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, F.E.R.C. STATS. & REGS. ¶ 31,252, 72 Fed. Reg. 39,904 (2007) *on reh'g* Order No. 697-A, *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, F.E.R.C. STATS. & REGS. ¶ 31,268, 73 Fed. Reg. 25,832 (2008) *clarified Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities,* 124 F.E.R.C. ¶ 61,055 (2008), *appeals pending* Montana Consumer Counsel v. FERC (9th Cir. No. 08-71827). The APPA and certain other commenters took the position in that rulemaking that the FERC should separately assess applicants' generation market power in long-term power supply product markets. The FERC, however, declined to adopt this recommendation. The APPA has accordingly filed a petition for review of the FERC's orders. American Pub. Power Ass'n v. FERC, No. 08-72675 (9th Cir. filed June 23, 2008). If the market design reform proposal put forth in this article is implemented, it would be even more important to separately assess the generation market power of applicants in markets for long-term power supply products.

221. Because the pricing regimes would be different for the RTO's cost-based short-term energy and ancillary services markets and the market-based forward bilateral market, opportunities for gaming and arbitrage between the two markets could arise, to the benefit of suppliers/traders and the detriment of electric consumers. For example, sellers might attempt to bifurcate their generation portfolios, dedicating only their inefficient, higher cost units to the RTO-run market, while making market-based forward sales from their lower cost, more efficient units. (This approach might make economic sense, given that the lower-cost generation units are likely to be base-load and shoulder units, which might more appropriately be dedicated to longer-term bilateral agreements.) Such a strategy would maximize their profits from sales made under market-based rate authority. To prevent this, MMUs would have to be vigilant in reviewing bids from sellers into the short-term energy and ancillary services markets. If abuses are detected, it might be necessary to consider imposing a "full portfolio" or "slice of system" short-term market pricing requirement on such sellers.

222. PROVIDER OF LAST RESORT (POLR), http://www.puc.state.tx.us/ocp/electric/polr/POLR.cfm (last visited Sept. 19, 2008).

featuring a series of auctions for tranches of supply over a two to four year period).[223] In many such states, the utilities themselves are not allowed to construct new generation, although their unregulated affiliates can do so (with no obligation to supply power to the regulated utility).[224] And of course, in states that have not implemented retail access, the incumbent utilities still have a state-imposed obligation to serve retail customers that requires them to build or contract for sufficient generation resources to meet their future loads.

State public utility commissions (and consumer-owned utilities) certainly question federal interference in their state and local level generation resource/adequacy decisions. But the case law is evolving in a direction that implies a court challenge to such an assertion of federal jurisdiction over overall resource adequacy levels would be problematic.[225] We believe that a FERC-approved RTO-wide overall resource adequacy requirement applying to all LSEs providing service in the RTO's footprint would likely be upheld if found necessary to maintain reliable wholesale power supply and transmission service.

Moreover, at this point, states that have implemented retail access regimes are beginning to realize that they may have inadvertently but adversely impacted the ability of their LSEs to serve their retail customers adequately and reliably in future years.[226] Substantial new generation resources are not forthcoming, reserve margins are shrinking, and locational capacity payments are very high.[227] Reliance on the "market" to supply new generation is fast becoming an untenable scenario in many states.[228]

223. One such auction is the New Jersey "Basic Generation Service" or BGS auction. A full description of the BGS auction regime can be found at: NEW JERSEY BD. OF PUB. UTIL., BGS AUCTION, http://www.state.nj.us/bpu/divisions/energy/bgs.html (last visited Sept. 5, 2008).

224. For a discussion of the main features of various state retail restructuring regimes, *see generally* APPA, WHAT IS HAPPENING IN STATE RETAIL CHOICE PROGRAMS?, http://appanet.org/aboutpublic/index.cfm?ItemNumber=16887 (last visited Sept. 18, 2008).

225. *See generally* Maine Pub. Utils. Comm'n v. FERC, 520 F.3d 464, 480 (D.C. Cir. 2008) (Court upheld prices the FERC set for capacity under ISO NE's FCM, finding it within the FERC's rate-setting jurisdiction to do so and noting that the underlying capacity requirement is computed by ISO NE in conjunction with a "regional standard-setting body"). A currently-pending petition for review in Conn. Dep't of Pub. Util. Control v. FERC, No. 07-1375 (D.C. Cir. filed Sept. 19, 2007) may provide a more definitive answer to the question of whether the FERC has the legal authority to impose through RTO tariffs such a regional installed capacity requirement. The FERC's reasoning for why it has such jurisdiction to impose such a requirement is explained in a number of orders. *See, e.g., ISO New England, Inc*., 122 F.E.R.C. ¶ 61,144 at P 10 (2008) ("ISO-NE's mechanism to determine [Installed Capacity Requirements] is a 'practice . . . affecting' the price of capacity, and as such falls within the Commission's jurisdiction").

226. NEWELL & DAVIS, *supra* note 12.

227. *Id.*

228. The latest state to reach this conclusion is New Jersey. Governor Corzine in April 2008 issued a draft energy plan for the state that explicitly finds reliance on the market for new generation is not a sound strategy. JON S. CORZINE, N.J. OFFICE OF THE GOVERNOR, DRAFT NEW JERSEY ENERGY MASTER PLAN 68 (2008) http://www.state.nj.us/emp/home/docs/pdf/draftemp.pdf ("We cannot continue to hope that market forces alone will lead to the construction of new plants by the market participants.") Moreover, a number of retail access states are moving to allow their LSEs to enter into long-term power supply contracts for renewable resources, to foster the development of such resources. For example, Massachusetts Governor Deval Patrick signed into law on July 2, 2008, the Green Communities Act, 2008 Mass. Acts 50, *available at* http://www.mass.gov/legis/laws/seslaw08/sl080169.htm (which, among other things, requires utility companies to enter into ten to fifteen year contracts with renewable energy developers to help these developers obtain financing to build their projects).

The time might, therefore, be ripe to undertake a coordinated state/federal RTO-by-RTO review of generation and demand resource adequacy issues. If state-regulated investor-owned utility LSEs can develop generation and demand resource plans for approval by their state regulators that meet relevant state requirements and goals, while also assuring RTOs that sufficient future resources will indeed be available to ensure adequacy and reliability, then jurisdictional battles over these issues can perhaps be avoided, or at least minimized.[229]

Such LSE resource adequacy plans for state-regulated investor-owned utilities should ideally include "minimum requirements" assuring that competitive forces are brought to bear to the maximum extent possible in developing these plans, so that retail consumers benefit from wholesale competition through selection of the most economic power supply choices. In so doing, we believe these LSEs should be able to consider self-builds as generation resource options.[230] The availability of the self-build option, so long as proper safeguards are included, would bring additional discipline to bear on third-party suppliers submitting generation supply bids. Sufficient protections, however, must be included in the selection process to ensure that third-party suppliers' bids and proposed projects receive fair and equitable consideration.[231] Utility-

229. Public power systems in RTO regions, because they have retained their obligation to serve retail customers, already develop and implement such resource adequacy plans, under the supervision of their local governing bodies. They conduct periodic generation procurements, assessing "buy v. build" generation options, as well as the use of demand response and energy efficiency measures to reduce demand, in lieu of securing additional generation. Because they are not-for-profit and do not earn a return on owned generation assets as investor-owned utilities do, they approach these decisions from a consumer-benefit perspective.

230. States are already considering regimes that provide a greater role for their incumbent utilities in the construction or procurement of generation. Examples include steps to allow incumbent utilities to build generation facilities (as in Connecticut) or to procure power through long-term contracts (as in Maryland). *See, e.g.*, MD. PUB. SERV. COMM'N, INTERIM REPORT OF THE PUBLIC SERVICE COMMISSION OF MARYLAND TO THE MARYLAND GENERAL ASSEMBLY, PART I: OPTIONS FOR RE-REGULATION & NEW GENERATION 33-34 (2007) http://www.psc.state.md.us/psc/Reports/MD%20PSC_Interim%20Report%20to%20the%20MD%20General%20Assembly_Part%20I-Options%20for%20Re-regulation%20and%20New%20Generation_12.03.07.pdf. Connecticut enacted a law in July 2005 that allows the state's regulated utilities to build up to 250 MW of peaking capacity. APPA, WHAT IS HAPPENING IN STATE RETAIL CHOICE PROGRAMS? AUGUST UPDATE: A FOCUS ON OBTAINING POWER SUPPLY (2006), http://www.appanet.org/aboutpublic/index.cfm?ItemNumber=16887. But, the utilities did not submit proposals under this law. In 2007, another law was enacted requiring that the utilities submit a plan to Department of Public Utility Control (DPUC or CT DPUC) in early 2008 to build peaking generation plants. Connecticut Light and Power submitted a proposal to build a 200 MW diesel-fired plant and sixty-five MW natural gas-fired plant. United Illuminating has proposed building jointly with NRG two 194 MW and one ninety-seven MW natural gas-fired plants. *See also* Conn. Dept. of Pub. Util. Control News Release, DPUC Receives Proposals for Peaking Generation Plants (Mar. 5, 2008), http://www.dpuc.state.ct.us/DPUCinfo.nsf/6388afa2e804605f852565f7004e9e87/09b7ebe93571c2e385257403005416e6?OpenDocument; CONNECTICUT GENERAL ASSEMBLY OFFICE OF LEGISLATIVE RESEARCH, http://www.cga.ct.gov/olr (last visited Sept. 18, 2008). In June 2008, the DPUC selected three peaking plants for cost recovery, including one of UI/NRG's proposed plants, as well as a 360 MW plant owned by Bridgeport Energy and a 130 MW PSEG-owned plant. Conn. Dept. of Pub. Util. Control News Release, Conn. Elec. Customers Will Save Hundreds of Millions – DPUC Makes Decision on Selection of Elec. Peaking Generation Plant Projects (June 25, 2008) http://www.dpuc.state.ct.us/DPUCinfo.nsf/6388afa2e804605f852565f7004e9e87/5deeae4ad091b47d8525747300509827?OpenDocument.

231. The National Association of Regulatory Utility Commissioners (NARUC) and the FERC have been participating in a Competitive Procurement Collaborative to identify state power supply procurement practices

build options should be judged using the same standards as other supply options, with no preferential consideration of utility or utility affiliate proposals, or the right by the utility or its affiliates to "trump" other bids.[232] Utility LSEs should also be able to "team" with third-party suppliers to develop joint project bids.[233]

Demand response resources should be fully considered in developing LSE resource portfolios. Because demand response and energy efficiency resources may, in many cases, be the lowest-price supply option (and likely the lowest carbon emitter as well), they should be an important part of an LSE's resource portfolio. Again, LSEs should have the ability to "self bid" demand response and energy efficiency reductions into their resource portfolios, either on their own, or in conjunction with third-party suppliers of such services. Given that many utility LSEs already provide retail service to end-use customers, they may in fact be best positioned to deliver demand response and energy efficiency services to them. However, the RTO should have the right to impose technical

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throughout the country that can be used to meet the ongoing challenges of ensuring cost-effective electric generation for retail customers. With funding from the United States Department of Energy, Susan Tierney and Todd Schatzki prepared a study of state procurement practices for the Collaborative. SUSAN F. TIERNEY & TODD SCHATZKI, NARUC, COMPETITIVE PROCUREMENT OF RETAIL ELECTRIC SUPPLY: RECENT TRENDS IN STATE POLICIES & UTIL. PRACTICES (2008), http://www.naruc.org/Publications/NARUC%20Competitive%20Procurement%20Final.pdf. This study lays out a number of safeguards states have used to prevent improper utility self-dealing in such procurements, including use of a third-party monitor, measures to increase the transparency of the process, codes of conduct to prevent improper information-sharing, and making detailed bidding information packages available to all bidders. *Id.* at iv-v. For more information, *see generally* Competitive Procurement -- A NARUC-FERC COLLABORATIVE PROCESS, http://procurement.webexworkspace.com/login.asp?loc=&link (last visited Sept. 19, 2008).

232. *See, e.g., Southern Power Co.*, 104 F.E.R.C. ¶ 61,041 at P 24 (2003). The FERC set for hearing approval of two proposed Power Purchase Agreements (PPAs) between unregulated wholesale power marketer Southern Power and its regulated retail utility affiliates Savannah Electric and Georgia Power, noting that:

> the Protestors have raised concerns regarding the RFP process [conducted in the State of Georgia to procure power to serve Georgia retail customers] and the impact of the PPAs on wholesale competition. Protestors contend that Southern Power has failed to demonstrate that the PPAs are the product of a fair, non-discriminatory, and non-preferential process which is not injurious to wholesale competition in the region.

Id. The request for approval of these PPAs was later withdrawn, which withdrawal the FERC permitted by notice issued August 4, 2004, in *Southern Power Co.*, 108 F.E.R.C. ¶ 61,134 (2004). However, the FERC subsequently found that the withdrawal of the PPAs did not resolve the issues of affiliate abuse and whether certain jurisdictional rates and practices affecting rates remained just and reasonable and not unduly discriminatory or preferential. It therefore initiated a section 206 investigation into the Southern Company's implementation of the FERC's Standards of Conduct. *Southern Co. Servs., Inc.*, 111 F.E.R.C. ¶ 61,146 at P 31 (2005). The case was eventually settled, but not without controversy. *Southern Co. Servs., Inc.*, 117 F.E.R.C. ¶ 61,021 (2006). Among other things, it sparked correspondence between Rep. Henry Waxman, (D-CA), then Ranking Minority Member of the House Committee on Government Reform, and FERC Chairman Joseph Kelliher regarding the procedures used to negotiate the settlement. Letter from Henry Waxman, California House Representative, to Joseph Kelliher, FERC Chair (March 27, 2006), *available at* http://www.rawstory.com/news/2006/Waxman_questions_sweetheart_deal_0327.html.

233. CONNECTICUT DEPT. OF PUB. UTIL. CONTROL NEWS RELEASE, DPUC RECEIVES PROPOSALS FOR PEAKING GENERATION PLANTS (2008), http://www.dpuc.state.ct.us/DPUCinfo.nsf/6388afa2e804605f852565f7004e9e87/0 9b7ebe93571c2e385257403005416e6?OpenDocument (discussing joint United Illuminated/NRG proposal to construct new generation).

requirements and calculation criteria on demand response resources included in LSE resource portfolios, to ensure that these resources in fact perform as intended, and that "phantom" demand response is not included in the LSE's portfolio.

In addition, state requirements and policy preferences for fuel diversity (*e.g.*, state renewable portfolio standard (RPS), energy efficiency goals, and regional carbon mitigation regimes) should be honored to the maximum extent possible in developing LSE resource portfolios. The RTO, however, should develop "umbrella" criteria to ensure that the LSEs' state-approved resource portfolios are both technically feasible and operationally reliable. (For example, a 100 percent wind portfolio might meet or exceed a state RPS requirement, but it would not necessarily be operationally feasible or reliable from the RTO's standpoint.)

In addition to fuel diversity and balance between generation resources and demand response/energy efficiency, the optimal LSE power supply portfolio should have temporal diversity. A mix of owned and contracted-for generation resources with varying terms (*e.g.*, five to thirty years) would protect consumers from having too many financial eggs in one power supply basket. LSEs should also be allowed to use appropriate defensive (as opposed to speculative) hedging instruments to minimize associated financial risks.

Finally, the RTO should give expedited consideration to transmission service requests (be they for physical transmission rights, FTRs, or LTTRs) associated with implementation of an LSE's approved resource plan. Congress, by passing as part of the Energy Policy Act of 2005 new FPA section 217(b)(4),[234] signaled its strong interest in having the FERC ensure that LSEs obtain the transmission service needed to fulfill their long-term service obligations. If LSEs are to enter into new resource arrangements of sufficient firmness and term to support substantial new generation resources, the associated transmission service will have to be made available, and sufficient transmission facilities constructed to ensure delivery of owned and contracted-for resources at a reasonable cost.

It is our hope and expectation that the reduction in the role of RTO-run centralized energy markets, and the eventual elimination of locational capacity markets, will reduce the high operational and administrative costs of RTOs, as well as the complexity and lack of accountability of RTOs for the results of their Day-Two RTO markets. We think such changes would benefit consumers.

VI. CONCLUSION

We recognize that implementation of a Day 1.5 RTO regime, along the lines of what we propose in this article, would take a substantial period of time. Many thorny transition issues would have to be resolved. Substantial institutional and political obstacles exist. Moreover, differences among RTOs and the retail regulatory regimes in the states they serve, as well as their different stages of development, likely would require customized application of this

234. 16 U.S.C. § 824q(b)(4) (2006). Jay Morrison argues in his article in this Journal that the FERC has made only "some progress" in implementing this new section and that its record on this score is "mixed." MORRISON, *supra* note 41, at 632.

proposal in each RTO in a way that recognizes and accommodates these differences. Hence, we suggest this reform proposal as one way to reach what we regard as necessary long-term goals for the electric utility industry, to foster rational debate on these issues.

This debate needs to take place. RTO-run centralized power supply markets are not working as originally envisioned, with substantial negative implications for the economy, reliability and the general well-being of the population in RTO regions. It is our hope that this article will contribute to a constructive dialogue regarding needed reforms to these wholesale electricity markets. The first step in starting such a dialogue, however, will be for those who advocate "competition" in wholesale electric markets to acknowledge that there are serious problems with RTO-run centralized power markets. The debate should no longer be about who can best massage the statistics or whether it is more virtuous to support "competition" or "regulation." Instead, we all must work together to develop a regulatory regime for electricity markets in RTO regions that will truly benefit consumers, businesses and the environment. Unless the industry and its regulators can agree on a market design and regulatory paradigm that fairly balances the interests of both load and generation, the electric utility industry will be condemned to continued upheaval.