

UNITED STATES OF AMERICA  
ELECTRIC ENERGY MARKET COMPETITION  
INTERAGENCY TASK FORCE  
AND THE  
FEDERAL ENERGY REGULATORY COMMISSION

Electric Energy Market Competition Task Force

| Docket No. AD05-17-000

**COMMENTS OF THE  
TRANSMISSION ACCESS POLICY STUDY GROUP**

The Transmission Access Policy Study Group (“TAPS”) submits this response to questions posed in the October 13, 2005 Notice Requesting Comments on Wholesale and Retail Electricity Competition issued by the Electric Energy Market Competition Interagency Task Force (“Task Force”) and the Federal Energy Regulatory Commission (“FERC”).<sup>1</sup> While not attempting to answer all of the questions posed, TAPS seeks to provide guidance on serious problems that prevent competitive forces from operating efficiently to produce the lowest cost and most reliable electricity supply possible for the American consumer. TAPS begins by outlining its major concerns in response to several of the Overview Questions, and then develops these concerns in response to a number of the Wholesale Market Questions.<sup>2</sup>

TAPS is an informal association of transmission-dependent utilities (“TDUs”) in more than 30 states, promoting open and non-discriminatory transmission access.<sup>3</sup> As entities entirely

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<sup>1</sup> By separate motion, TAPS is seeking to file these comments out-of-time.

<sup>2</sup> TAPS reproduces below only those questions to which it is responding.

<sup>3</sup> TAPS is chaired by Roy Thilly, CEO of Wisconsin Public Power Inc. Current members of the TAPS Executive Committee include, in addition to WPPI, representatives of: American Municipal Power-Ohio; Blue Ridge Power Agency; Clarksdale, Mississippi; Electricities of North Carolina, Inc.; Florida Municipal Power Agency; Geneva, Illinois; Illinois Municipal Electric Agency; Indiana Municipal Power Agency; Madison Gas & Electric Co.; Missouri River Energy Services; Municipal Energy Agency of Nebraska; Northern California Power Agency; Oklahoma Municipal Power Authority; Southern Minnesota Municipal Power Agency; and Vermont Public Power Supply Authority.

or predominantly dependent on transmission facilities owned and controlled by others, TAPS members look to competitive power supply markets to help them provide affordable and reliable service to their customers. While TAPS has long-supported open transmission access as a means to make wholesale markets competitive, it is very concerned that the competitive market goal has lost sight of the ultimate intended beneficiary – the consumer. TAPS hopes that the Task Force’s work will help right the ship.

Communications regarding these proceedings should be directed to:

Roy Thilly, CEO  
WISCONSIN PUBLIC POWER INC.  
1425 Corporate Center Drive  
Sun Prairie, Wisconsin 53590  
Tel: (608) 837-2653  
Fax: (608) 837-0274  
Email: rthilly@wppisys.org

Robert C. McDiarmid  
Cynthia S. Bogorad  
Mark S. Hegedus  
SPIEGEL & MCDIARMID  
1333 New Hampshire Ave, NW  
Washington, DC 20036  
Tel: (202) 879-4000  
Fax: (202) 393-2866  
Email: robert.mcdiarmid@spiegelmc.com  
cynthia.bogorad@spiegelmc.com  
mark.hegedus@spiegelmc.com

## **I. Overview Questions**

### *1. What are the critical elements or attributes of competition in wholesale electricity markets that the Task Force should examine?*

In assessing the state of competition in the electric industry at wholesale and retail, it is very important to recognize that competition is not the end in itself. The objective of regulatory structure should be to achieve consumer benefits. Competition should be employed where it will concretely (not merely theoretically in the undefined and never reached long term) result in better service and lower costs for customers. TAPS has been a strong supporter of wholesale competition, transparent markets and independent, robust regional transmission grids as the backbone essential for competitive markets to work. However, TAPS is very skeptical of the claimed benefits of the organized Regional Transmission Organization (“RTO”) markets in the

Eastern Interconnection that have adopted locational marginal pricing (“LMP”). One can hire a consultant to do a study that comes out any way one chooses. The real test, however, is the experience of those who must transact in these markets, day-in and day-out. Recent American Public Power Association (“APPA”) and ELCON White Papers show that consumers are questioning the benefits of these markets, while generators that are the most likely beneficiaries are applauding them.<sup>4</sup> This is unfortunate.

TAPS members respond to the Task Force’s questions from their perspective as load-serving entities (“LSEs”) obligated to secure economic, reliable electricity supplies for their customers (both wholesale and retail).<sup>5</sup> We see organized markets that have very high and growing administrative and uplift costs, often driven by the RTOs’ imaginative creation of new “markets,” which for TAPS members are dwarfing any benefits from the markets themselves. The costs are clear and identifiable. The benefits are speculative, based on assumptions of where energy costs would be without these markets.

Also, TAPS is very concerned that the LMP market design, while elegant on paper, has many unintended consequences that are driving costs up and threatening long-term transmission and generation adequacy.<sup>6</sup> Congestion pricing creates major new stakeholders in maintaining

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<sup>4</sup> American Public Power Association, *Restructuring at the Crossroads: FERC Electric Policy Reconsidered* (Dec. 2004), available at <http://www.appanet.org/files/PDFs/APPAWhitePaperRestructuringatCrossroads1204.pdf>. Electricity Consumers Resource Council, *Problems in the Organized Markets* (Apr. 2005), available at <http://www.elcon.org/Documents/Publications/ELCONSpecialReportApril2005.pdf>.

<sup>5</sup> As noted at the outset, TAPS responds to the Task Force’s Overview Questions by setting forth major concerns, which are developed with specific examples in response to a number of the Wholesale Market Questions.

<sup>6</sup> A further problem with LMP markets is that many of the consumers that are supposed to respond to the LMP signals won’t hear them. Given the uniform requirement for LSEs under state regulation to spread costs throughout a service territory for retail ratemaking purposes, one cannot assume price signals are conveyed in a way that will lead to efficient decisions. The unintended consequences of sending price signals, however theoretically efficient if heard by all consumers, only to consumers of TDUs/small LSEs that have no ability to socialize the costs over a larger area, potentially eliminating some competitors with no increase in efficiency, should be recognized and addressed. The only message that would be recognized by sending a signal that misses most of its intended

congestion. Similarly, the recent development of locational, centrally clearing capacity markets (“installed capacity” or “LICAP” markets) creates stakeholders that gain from scarcity and constraints. In both instances, the construction of a new line or generator is likely to lower profit for existing generators in constrained areas, thus creating an incentive for incumbents to fight new entry and seek to impose entry barriers. Given the difficulty of entry for generation other than gas-fired generation and the major difficulties that face construction of significant new transmission, we believe LMP markets are not likely to get the facilities built that would create a robust power system for the benefit of consumers. Instead, they are likely to lead to a minimalist transmission system and focus the development of generation on gas-fired units close to load. The results of these incentives will have major long-term negative consequences for electricity costs for consumers and for potential shortages.

The high and volatile prices in LMP markets make operations for smaller load-serving utilities considerably more risky. In most RTO regions, LSEs have no choice but to participate in these volatile spot markets. As the RTOs grow and market power and adequacy concerns become more evident, these markets are becoming even more complex (*i.e.*, LICAP), with the result that we are substituting rate regulation for an even more complex form of “market” regulation (delegated to non-governmental entities, no less), not competition.

We also know that these markets are causing suppliers to be unwilling to enter into new long-term power contracts. Many small systems seeking supply today issue RFPs and get very few responses for firm power on a long-term basis. When they do get a response from a seller other than the utility that controls the transmission system that surrounds them, it is likely that

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recipients would be the effective imposition of an illegal price squeeze that invites transfer of the TDU’s system or (in retail access states) its customers to the dominant supplier.

there will be no transmission capacity available for them to reach the low bidder. This forces the supply contract back to the dominant transmission supplier, generally at a much higher price.

Wholesale electricity markets must be designed to encourage the long-term investments needed to support robust competition. Unfortunately, RTOs have shown themselves to be very short-term focused, relying on spot market price signals to spur generation and transmission construction and providing only one-year (or shorter) congestion hedges. This short-term focus is made worse by RTO transmission planning practices, where in many cases the RTO acts merely as a “clearinghouse” that identifies needs and allows generation and participant-funded transmission solutions to “compete with each other” to meet them, instead of the RTO’s being directly accountable for getting transmission built. As explained in TAPS’ *Long Term Transmission Rights Comments*,<sup>7</sup> these policies support, at best, gas-fired generation installed close to load and a minimalist grid. Renewable alternatives will similarly suffer.

We cannot remain on this course. Any short-run efficiencies that LMP markets produce will be worth less and less if such markets discourage needed investments in transmission as well as baseload and fuel-diverse generation. Short-term-focused RTO markets, although possibly well-suited to some suppliers in retail access states, must be adapted to also meet the needs of the entities most likely to finance the next generation of baseload resources: LSEs obligated by contract or state law to provide reliable service at stable prices. Unless the generation that can produce low-cost energy is brought back into the mix, RTOs will become just a very expensive

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<sup>7</sup> Comments of the Transmission Access Policy Study Group in *Long Term Transmission Rights in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Docket No. AD05-7-000 (filed June 27, 2005) (“TAPS Long-Term Rights Comments”), available at <http://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=10635332>.

means to deliver high-cost energy and to allocate increasingly scarce, natural monopoly transmission resources to those prepared to pay the most.

The impacts of current short-term (and short-sighted) market designs are real. Competitive supply options for smaller utilities have decreased dramatically over the last five to eight years. In addition, truly independent power producers (“IPPs”) appear to becoming a relic of history,<sup>8</sup> and IPPs face significant credit problems which make it very risky for small LSEs to contract with IPPs. These problems are aggravated by market designs that do not guarantee long-term transmission rights, which undermines the ability to enter into long-term power supply contracts.

At the same time, power supply markets remain concentrated or are becoming more so. Large, vertically-integrated utilities are purchasing IPP generation at bargain prices, increasing their market dominance. If we add to this problem the prospect of more mergers as a result of the repeal of PUHCA, the fate of competitive markets would appear dim.

This is obviously a negative view, particularly in organized RTO markets. What we need is an objective and thorough evaluation of benefits and a restructuring of the markets to provide much more certainty for customers that will help achieve low and stable electricity prices over the long term. TAPS believes that the most important thing that can be done to achieve this objective is construction of fuel-diverse baseload resources and robust regional transmission systems to move output to where it is needed. Market design is significantly easier if there is a robust transmission grid, so that customers have many supply options and generators are forced to truly compete against each other to serve load. Other key elements are a system that allows

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<sup>8</sup> Some of the strongest “IPPs” are the affiliates of vertically integrated utilities, *e.g.*, Exelon, Southern Power, and Constellation.

customers to obtain long-term transmission rights for new resources in order to achieve delivered price certainty for major investments; truly transparent spot markets; long-term markets that are disciplined and reflect just and reasonable prices; and a policy that tests the consumer benefits of mergers and errs on the side of maintaining competitive wholesale markets not dominated by a few suppliers.

3. *What benefits have occurred because of competition in wholesale and retail electricity markets? What additional benefits are expected? What benefits were forecasted and have not occurred? Why? What harms have occurred because of competition in wholesale and retail electricity markets?*

The focus on designing wholesale electricity markets to support short-run market competition has resulted in policies that discourage the long-run investment needed to ensure robust competition and just and reasonable prices over the long term. As might be expected from an industry characterized by highly capital-intensive, long-lived assets, the long-term transmission rights needed to support such investments had been the norm. They were a key ingredient of FERC's Order 888 regimen. However, they somehow got lost in the shuffle when new LMP markets, which are focused on maximizing short-term efficiency, were created.<sup>9</sup>

Indeed, not only have new long-term transmission rights not been made available, existing long-term rights have wrongly been branded as incompatible with the new market structure. At a time when RTOs and FERC should be actively looking for ways to encourage new long-term investment in the plants necessary to ensure reliability and competitive markets, policies that dismantle existing long-term arrangements are a step in the wrong direction.

A cornerstone of a well-functioning electric industry has always been sanctity of contract, and another must be regulatory trust. Unless pre-existing long-term contracts are honored, there

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<sup>9</sup> See TAPS' *Long-Term Transmission Rights Comments* at 6-8, 13, 19.

will be no reason for any entity to negotiate replacement or transition arrangements for grandfathered contracts. On a forward-looking basis, market participants will be unable to make economic and strategic choices with any assurance that the parties will be bound to their bargains. Such an outcome would disrupt ongoing efforts to craft an orderly transition to RTOs/ISOs and restructured electricity markets nationwide. In addition, without the assurance that contractual agreements will be enforced over the long run, generation and transmission projects that require long-term commitments will grind to a halt or require significantly higher risk premiums, compromising the reliability of the electric system and undermining competition in the long run.

4. *What are the major public policy concerns that the Task Force should examine in its review of competition in wholesale and retail electricity markets?*

a. Market Power

One major policy concern is whether wholesale markets are structurally competitive. It was and is naïve to expect that merely requiring open access transmission somehow made or would make these markets workably competitive.<sup>10</sup> The odds are stacked against such an outcome. Except in a few states where legislation or regulatory requirements mandated divestiture of generation, much of the industry remains vertically integrated and traditional incumbents remain dominant in their control areas or transmission regions. While the initial enthusiasm for markets created significant new entry in some regions, the new plants were often built in areas with insufficient transmission capacity to move the supply to the loads that wanted

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<sup>10</sup> The Task Force should be wary of RTO market monitor conclusions that a particular market is workably competitive, because the monitors usually help write the market rules governing the markets and have a vested interest in concluding that those rules work.

to purchase it.<sup>11</sup> Further, the next round of needed entry is proving difficult, because of barriers to long-term contracting, including credit concerns and the absence of an underlying transmission infrastructure or market design to support such transactions. *See* responses to Questions II.A.6., 8., and II.D.1-5 below. On top of these historical barriers to competition, organized RTO markets, especially those Day-2 RTO markets that FERC seems to favor, are increasingly complex and present opportunities for repeated “games” that allow sophisticated sellers to collusively exercise market power, either overtly or tacitly. Detecting market power exercise in electricity markets, which is already difficult, will become more so. As icing on the cake, demand in electricity markets remains inelastic, increasing the likelihood of profitable market power exercise.

So far, FERC has generally sought to regulate the market power exercise out of the market, despite repeated advice from the antitrust agencies (as well as market participants, such as TAPS), that structural solutions (divestitures; increased timely, likely and sufficient entry; *etc.*) hardwire the incentives for competitive behavior into the market structure, unlike the game of cat and mouse encouraged by FERC’s behavioral approach. As a result of this approach towards market power, FERC policies allow the exercise of “warranted market power,”<sup>12</sup> and

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<sup>11</sup> For example, the state of Maine saw considerable generation entry in recent years, but the New England transmission grid is insufficient to move the energy from the new plants to loads that need it. In Louisiana, it claimed that some 18,000 MW of new IPP generation has entered, but that generation remains trapped because of Entergy’s investment-starved transmission grid (which condition pre-dated Hurricane Katrina’s devastation).

<sup>12</sup> In *PJM Interconnection, L.L.C.*, 107 F.E.R.C. ¶ 61,112, P 18 (2004), the Commission said it sought only to “prevent the unwarranted exercise of market power” indicating that the Commission finds “warranted market power exercise” acceptable.

require mitigation of market power only in egregious cases, sometimes, for example, where prices are allowed to rise 200% above competitive levels.<sup>13</sup>

While FERC has ample conditioning authority, it has thus far proven itself reluctant to exercise this authority broadly in order to encourage structurally competitive markets. Thus, the Task Force would serve the public interest by spawning a debate on whether more needs to be done to create the kinds of structurally competitive markets that will be necessary to make current market-based regulatory policies succeed. If FERC (or some other agency) should have more authority to take the steps to ensure structurally competitive markets, the Task Force's work can lay the foundation for appropriate legislative efforts to address this need.

b. Transmission Adequacy

Related to the question of structural market power is the current inadequacy of the transmission grid. Robust transmission will provide buyers with a meaningful choice of sellers and bring real competitive forces to bear on the sellers. However, transmission investment has miserably failed to keep pace with the growth in electricity demand,<sup>14</sup> as well as the changes in electricity market structures (*e.g.*, transactions across multiple control areas, LMP market design that concentrates and accentuates the pricing power of dominant sellers attributable to transmission constraints). The current system is not producing the robust grid required to foster competitive wholesale markets. As a result, the competitive electricity markets envisioned by the Energy Policy Acts of 2005 and 1992 are rendered more dream than reality.

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<sup>13</sup> Midwest ISO, FERC Electric Tariff, Third Revised Volume No. 1, Section 64.2.1.b., *accepted in Midwest Independent Transmission System Operator, Inc.*, 108 F.E.R.C. ¶ 61,163, at P 315 (2004), *order on reh'g*, 109 F.E.R.C. ¶ 61,157, P 220 (2004).

<sup>14</sup> See E. Hirst, *U.S. Transmission Capacity: Present Status and Future Prospects*, prepared for the Department of Energy and the Edison Electric Institute (Aug. 2004), *available at* [http://www.eei.org/industry\\_issues/energy\\_infrastructure/transmission/USTransCapacity10-18-04.pdf](http://www.eei.org/industry_issues/energy_infrastructure/transmission/USTransCapacity10-18-04.pdf).

As discussed further below in response to Question II.D.1., TAPS' White Paper, "Effective Solution for Getting Needed Transmission Built at Reasonable Cost," which is Attachment 1 to these Comments, analyzes current barriers to transmission construction and presents concrete proposals to encourage the construction of needed transmission infrastructure.

5. *In what significant ways do wholesale and retail electricity markets differ from other energy or commodity markets? What implications do their differences have for public policy?*

Besides some of the obvious differences, such as the inability to store electricity and the need to produce electricity as it is consumed, both of which raise the risk of market power exercise, the design of wholesale electricity markets must take into account the dynamics of the AC transmission grid. Transmission is a natural monopoly characterized by network economies. The fundamental problem is one of externalities and free riders, causing market failures: the benefits of a transmission investment go to numerous market participants, so nearly all socially beneficial investments will be made only if nearly all of the beneficiaries pay for the investment. DC facilities can be dispatched to functionally permit their use only by those who will pay. In contrast, proposals such as participant funding, which attempt to assign to particular market participants the costs of transmission upgrades, even though the upgrades provide broader benefits, make little sense in an AC network. Most AC upgrades have multiple uses and provide multiple benefits, such as providing additional transfer capability, easing constraints that could be remote from the upgrade, reducing losses, improving voltage, enhancing reliability, and more. Because of the multiple purposes and the long-term needs typically addressed by transmission expansion, capacity is added in lumps that are more economic and efficient than the band-aid approach encouraged by, and the likely result of, participant funding. Even if it were possible to identify beneficiaries on day one, those beneficiaries and the magnitude of benefits

will change over time, with other changes to the grid and its use. And once an AC upgrade is in place, access to the upgrade cannot be controlled, producing a significant free-rider problem that deters market participants from being willing to step forward to shoulder the upgrade costs.

## **II. Wholesale Market Questions**

### *A. Wholesale Supply Trading and Participation*

#### *4. What opportunities exist for generation owners to sell output in wholesale markets?*

While thousands of megawatts of new entry are sometimes touted as a benefit of the movement toward reliance upon competitive forces, such entry has not proven profitable for many IPPs and, instead, has accrued only to the benefit of the traditional, vertically integrated utilities. The poster-child for this phenomenon is Entergy. It is claimed that 18,000 MW of “competitive” generation is connected to the Entergy transmission system, yet TAPS members, such as Lafayette Utilities System, are unable to secure necessary transmission access to purchase any of this output on a long-term or firm basis. As a result, LUS has been forced to build 200 MW of peaking capacity on its own transmission grid despite the existence of plentiful generation resources in the region.<sup>15</sup> At the same time, Entergy purchases previously independent generation that is forced into bankruptcy because of the lack of market access, thus dealing a blow to competitive markets by eliminating a competitor and increasing Entergy’s

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<sup>15</sup> See FERC Docket No. RM04-7, January 28, 2005 Written Statement of Terry Huval on behalf of the Lafayette Utilities System and the Transmission Access Policy Study Group, at 8, *available at* <http://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=10391023>; and March 31, 2005 Reply Comments of Terry Huval on behalf of the Lafayette Utilities System, at 8-9, *available at* <http://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=10476030>. While some may view a generator in every backyard as an acceptable solution, such an approach fails to address the need for fuel diversity and long-term reliability and efficient generation investment, much less the generation competition on which the Commission has premised its policy for pricing wholesale power.

generation dominance.<sup>16</sup> Entergy apparently then builds the needed transmission, rolls the cost of that transmission into the transmission rate for everyone (which it would not have done when the IPP was not affiliated) and charges that increased rate to the other IPPs who cannot reach markets.

5. *What opportunities exist for wholesale power buyers to purchase electricity in wholesale markets? Is demand (megawatts) a product that can be traded in the wholesale market?*

A significant disappointment for TAPS members is the continuing decline in power supply choices as well as the continuing increase in power supply prices.<sup>17</sup> As detailed in the APPA's comments submitted in response to the Task Force's questions,<sup>18</sup> TAPS member Blue Ridge Power Agency ("BRPA") began seeking in 2002 to replace 7-year power supply contracts expiring in 2005. It ended up with only one three-year contract and seven one-year contracts at significantly higher prices compared to the prices in the expiring contracts. Even though the passage of time and rising fuel prices could be expected to cause the prices in the new contracts to be higher, those prices are also high compared to the likely costs of production.<sup>19</sup> Much of the generation in the PJM region in which BRPA is located is coal-fired and nuclear, but the pricing in the new contracts reflects the dominant role that natural gas now plays in setting prices, even at times when gas is not a marginal fuel.

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<sup>16</sup> *Perryville Energy Partners, L.L.C.*, 109 F.E.R.C. ¶ 61,019 (2004), *reh'g denied*, 111 F.E.R.C. ¶ 61,006 (2005).

<sup>17</sup> TAPS member Electricities has found that where transmission is adequate, such as appears to be the case for the Duke Power transmission system, it has been able to secure alternatives to the incumbent (Duke).

<sup>18</sup> See November 18, 2005 Comments of the American Public Power Association, Docket No. AD05-17-000, at 25-27, available at <http://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=10885186>.

<sup>19</sup> This year's hurricanes have only aggravated the problem. TAPS Members report that prices for contract power in New England for delivery in 2008 are up by roughly 25% since July and by roughly 40% since the end of March 2005.

The problem is not limited to the relatively large loads of entities such as BRPA. Earlier this year, Anne Kimber, on behalf of the Iowa Municipal Utilities Association, explained the difficulties experienced by small systems of just a few megawatts in obtaining new power supply:<sup>20</sup>

Notwithstanding the OATT, inadequate transmission is driving—in fact, driving away – power supply choices. This process is extremely frustrating for municipal systems. Selecting and negotiating a new wholesale energy contract can easily be the most important decision a public power utility makes. The process of going through an RFP and negotiating a new power supply contract is costly and challenging in and of itself. To then have the selected deal fall through due to a lack of transmission availability from Missouri to Iowa, or Nebraska to Iowa, is downright frightening. If Calhoun County REC had not offered to serve Callender [0.6 MW], if MEAN had been unable to find a source to the east to serve Buffalo [1.5 MW], if MEC had not offered to serve Indianola [30 MW] and Hudson [3.5 MW], these cities would be without *any* power supply contracts. As it is, these and other cities have no effective choice and very little negotiating power.

This situation is hardly a testimonial to the competitiveness of our generation markets. Competitors don't count if you can't reach them cost effectively.

The Task Force should resist the simplistic response that wholesale purchasers, such as BRPA or small municipal systems in Iowa, can simply build a plant if prices in the market are not acceptable. FERC has noted that self-build often is not an alternative to purchasing:

[T]here are a number of reasons why market participants do not have the option of building capacity at a competitive cost, including lumpy generation investment, insufficient transmission

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<sup>20</sup> Written Statement of Anne Kimber on behalf of Midwest Municipal Transmission Group and TAPS for the December 7 Technical Conference, Docket No. RM04-7-000, at 7-8 (Dec. 7, 2004) (emphasis in the original), available at <http://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=10328815>. Ms. Kimber went on (*id.* at 8) to explain how this situation was frustrating to suppliers as well: “The consultant for Pocahontas, Iowa, a 4 MW municipal on the MEC system that is currently going out for power supply to commence January 1, 2006, was told by one supplier, who had initially expressed interest in responding to the RFP, that it would not bid because it did not wish to invest the time and money it would take to attempt to secure a clear transmission path.”

access, and insufficient access to fuels. Further, depending upon the facts and circumstances, a new generating facility is not always a comparable or feasible alternative to a long-term purchase

*AEP Power Marketing, Inc.*, 107 F.E.R.C. ¶ 61,018, P 155 (2004). FERC further observed that:

The concern with “lumpy” investment is that an LSE with a specific capacity need may not be able to build a facility to match that need. If it is too small, then the LSE will still need to buy long-term capacity and energy. If it is too big, then the LSE will be “long” and need to sell the power and may not have any customers, or may not have any interest in being a seller.

*Id.* at n.151.

More recent new plant proposals and investments have been made by large vertically integrated incumbents that have access to sites (often their own, existing sites) and that have retail service obligations that provide the revenues necessary to support the plants. Small LSEs, including TAPS members, look for (though don’t always find or are not offered) opportunities to invest in such projects. However, incumbent investment in new generation does not remedy, and even reinforces, underlying structural market power associated with the incumbent’s dominant position.

6. *Is there an organized regional market or exchange serving buyers and sellers in the region? What products does the organized market provide? What percentage of energy supplied is secured through organized markets and through bilateral trades? Are there liquid trading points in the region? What are the volumes traded? What is the trend of bid/ask spreads (getting greater or smaller)?*

TAPS members do not feel warm and fuzzy toward the RTOs that are responsible for organized regional markets, in part because of the upward-spiraling costs imposed by RTOs on market participants. We have watched individual RTO operating costs mount to several hundred million dollars per year. In 2004,<sup>21</sup> TAPS filed comments at FERC describing some of the

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<sup>21</sup> November 9, 2004 Comments of the Transmission Access Policy Study Group, Financial Reporting and Cost Accounting, Oversight and Recovery Practices for Regional Transmission Organizations and Independent System

impacts. For example, for TAPS member Wisconsin Public Power Inc. (“WPPI”), MISO administrative costs billed under MISO Schedules 10, 16 and 17 are expected to exceed \$1.8 million in 2005, more than WPPI’s total power supply staffing, operations and planning budget. The membership of TAPS member American Municipal Power-Ohio, Inc., a non-profit wholesale power and services provider whose members span the MISO/PJM seam, are subjected to paying RTO administrative costs amounting to approximately \$5.9 million annually, more than what AMP-Ohio itself spends annually to operate its own 24-hour, 365-day-a-year energy Control Center to dispatch approximately 5.5 million MWh of power to its members. The City of St. Charles, Illinois saw its cost to deliver 24 MW of 100% load factor power nearly double when the service moved from ComEd's OATT to PJM service.<sup>22</sup>

Beyond the costs billed directly by RTOs, market participants incur substantial costs in staffing to participate in innumerable stakeholder meetings, and for staffing and operational infrastructure (*e.g.*, computer hardware and software) to interface with the RTO. The cost of what amounts to grounds-up re-creation of each market participant’s internal power supply functions – operations, settlement, risk management – to fit with Day-2 RTO markets cannot be overstated. AMP-Ohio now maintains two full-time staff members just to manage its ever-

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Operators, Docket No. RM04-12-000, *available at* <http://elibrary-backup.ferc.gov/idmws/common/OpenNat.asp?fileID=10288194>.

<sup>22</sup> In January, February, March, and April, under the ComEd OATT, the delivery cost was \$44,122.60, \$45,146.08, \$44,963.13, and \$46,544.57 respectively, averaging \$45,194.10. In contrast, PJM delivery of this same 24 MW for the months of May and September (the City did not exercise its purchase option in the summer) cost \$84,419.20 and \$68,648.94, averaging \$76,534.07. Based on this before-and-after comparison, the move to RTO service increased the City’s cost by \$31,339.97 per month. Of course, there are many factors that contributed to this bottom line increase. For example, the rate increase that ComEd filed in Docket No. ER03-1335, which may account for approximately one-third of this increase, might or might not be considered a consequence of the move to RTO service. But components such as PJM incremental scheduling charges, PJM administrative charges, “Transitional Market Expansion” charges, “Expansion Integration” charges, “Black Start Service” charges, and “Spot Market Energy” charges net of “Transmission Congestion” revenues clearly were such a consequence, and for the two PJM months they averaged \$11,873. In addition, for reasons that are not apparent, the move to RTO service dramatically increased Regulation charges, *e.g.*, increasing them from \$1,019.44 for ComEd Regulation in April to \$9,002.25 for PJM Regulation in May.

changing RTO requirements and policies on behalf of its member municipal systems, and expects it will be necessary to add additional RTO-devoted staff in the coming months. And that does not take account of the substantial expenses for outside counsel to assist in its participation in numerous MISO and PJM proceedings before FERC. Taunton (Massachusetts) Municipal Lighting Plant has experienced a 15% increase in annual operating expenses because of ISO-NE's ever-growing and increasingly complex market initiatives. Other small systems have hired consultants to help manage their interface with RTOs.<sup>23</sup>

In its 2005 comments on RTO accountability,<sup>24</sup> TAPS described how WPPI had calculated that MISO's market-related administrative charges and uplift costs have increased its total power supply bill to its municipal members by 2-3% for the first four months of MISO's Day 2 market operations (which began on April 1, 2005). For another TAPS member (Missouri River Energy Services), MISO's market-related administrative and uplift costs during the same period increased the total cost of MRES-supplied power to its municipal member loads in the MISO footprint by more than 4%. Nor is this experience limited to MISO. Vermont Public Power Supply Authority, which represents approximately 1/2% of the New England load, has calculated that its share of ISO-NE's 2005 budget for operating expenses, debt service, and depreciation amounts to more than twice the cost of VPPSA's Power Supply Department,<sup>25</sup> and

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<sup>23</sup> For example, it was reported recently that Columbia, Missouri agreed to pay The Energy Authority up to \$356,725 per year for such assistance.

<sup>24</sup> August 26, 2005 Comments of Transmission Access Policy Study Group, Accounting and Financial Reporting for Public Utilities, Docket No. RM04-12-000, *available at* <http://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=10771460>.

<sup>25</sup> It is also significant that on average, 40% of the VPPSA Power Supply Department staff time is dedicated to managing interactions with ISO-NE and its markets.

represents a nearly 900% increase over VPPSA's share of NEPOOL's cost to operate a centrally dispatched pool.<sup>26</sup>

Clearly, before any sound conclusions about RTO benefits are made, the costs incurred by market participants, not just the RTOs, must be identified and included in the total cost calculation for any cost-benefit analysis.

Another serious concern with RTOs is that they focus exclusively on short-term markets and do little to support the development of the robust long-term markets that LSEs need to fulfill their obligations to consumers. Industry experience—including the experience of PJM, the most mature LMP market—has demonstrated that in the absence of long-term transmission rights and a robust transmission grid, LMP markets will not provide the economic incentives necessary to support investment in the capital intensive, long-lived, “lumpy” assets essential to creating and maintaining a fuel-diverse generation mix consistent with our national energy policy.<sup>27</sup> Markets that do not provide for sufficient long-term delivered price certainty will deter investment in new high-fixed-cost, low-marginal-cost units, such as the next generation of clean coal (and nuclear) baseload units that would benefit consumers by reducing regional LMPs and dependence on gas-fired plants.<sup>28</sup> To address this problem, RTOs must resolve bottlenecks that burden consumers with high prices, and they must create the transmission highways required for such generation –

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<sup>26</sup> Prior to ISO-NE, VPPSA members paid their share of New England Power Pool's operating cost to dispatch all available units on a least-cost basis. NEPOOL's operating costs were on the order of \$14 million annually, of which VPPSA's share would have been some \$70,000. ISO-NE 2005 budget for operating expenses, debt service, and depreciation is \$125,000,000, which adds \$625,000 to VPPSA's cost of serving its member systems. These estimates of VPPSA's share is based on its percentage of New England load (*i.e.*, approximately ½%); exact tracking of the allocation of ISO-NE operating costs is very difficult.

<sup>27</sup> See TAPS' *Long-Term Transmission Rights Comments* at 11-12, 29-30.

<sup>28</sup> *Id.* at 8-14.

the types of generation that have traditionally driven transmission development – and associated long-term rights to support investment in those plants.

As TAPS explained in its *Long-Term Transmission Rights Comments*, LSEs with a statutory or contractual obligation to serve their wholesale and retail customers, need long-term supply options. Many TAPS members supply their customers using energy produced from the resources in our portfolios, particularly baseload and intermediate resources. On a daily basis, if economic, we substitute spot market energy for energy that we would otherwise obtain from our own resources. While this optimization function is valuable, spot market energy purchases represent a very small percentage of total energy provided to our customers.<sup>29</sup>

For municipal utilities, such as many TAPS members, it would be politically impossible to rely heavily on spot market energy purchases. Imagine a utility director going to his/her board or city council and telling them that the utility plans to “float” on spot market prices and pass-through to residents whatever the market clearing price happens to be. Not only would this approach potentially expose ratepayers to excessive risk, it could have negative implications for the market as a whole. In evaluating the California market meltdown of 2000-2001, for example, FERC found that the IOU’s overreliance on the spot energy market to serve their loads exacerbated price volatility in the California markets.<sup>30</sup>

8. *What role have credit issues played in the ability of market participants to participate in wholesale markets, including forward markets?*

Credit difficulties have revealed that spot markets and building generation “on-spec” do not work to fund generation investment. New generation investment generally cannot be built

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<sup>29</sup> *Long-Term Transmission Rights Comments* at 5-6.

<sup>30</sup> *San Diego Gas & Elec. Co.*, 93 F.E.R.C. ¶ 61,294, at 61,998-99 (2000) (finding that over-reliance on the spot market exacerbated price volatility in the California markets).

absent a long-term contract, as Wall Street clearly told FERC during a conference examining generation funding issues:

Most capital for power infrastructure is provided by debt markets not equity markets. If you look at capitalization of power assets, as you probably heard this morning, we value stability. We're not in this to make a killing off of spiking peak power prices. We're putting capital into this business in opportunities that we think can provide long term stable reasonable returns and are on the low end of the risk adjusted spectrum.

*Compensation for Generating Units Subject to Local Market Power Mitigation in Bid-Based Markets*, Docket No. PL04-2 000, Transcript (“Tr.”) at 149 (Anderson, John Hancock).<sup>31</sup> The testimony reflects the reality that LSEs, not to mention generation developers, see today: investors will not fund projects unless they are backed by long-term contracts. Tr. at 153 (Bailiff, CSFB). These long-term contracts are a good deal for consumers because their lower risk means lower financing costs.<sup>32</sup> In the words of one investment banker: “I think the economists like volatility, but the marketplayers don’t.” Tr. at 262 (Newman, Warburg Pincus). As describe above (Questions I.3. and II.A.6.), long-term transmission rights, which are conspicuously absent in organized markets, are the key to allowing LSEs to make the long-term generation commitments necessary to providing the financial security new generation, especially coal and wind projects that must be remote from load, need.<sup>33</sup>

9. *Are there competitive processes by which distribution utilities solicit proposals for native load or default service?*

See response to Question II.A.5. above.

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<sup>31</sup> Transcript available at <http://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=10071892>.

<sup>32</sup> As described by John Hancock’s representative, a debt investor in a project backed by a long-term contract with an LSE might look for a seven percent return, whereas an equity investor in a project that relies on volatile spot markets might require a twenty-five percent return. Tr. at 207-09 (Anderson).

<sup>33</sup> TAPS’ *Long-Term Transmission Rights Comments* at 11.

11. *How should the performance of wholesale markets in serving the needs of various types of power sellers (e.g., marketer, generator, independent producer, merchant, public utility, nonpublic utility, qualified facility, renewable power producer, co-generator) be measured?*

TAPS is concerned that neither this question nor any other asks “how should the performance of wholesale markets in serving the needs of various types of power *buyers* be measured?” The answer to that question is that RTO markets must be adapted to accommodate the needs of LSEs. Current organized markets are tailored to an imaginary marketer/merchant-generator promised land in which LSEs purchase all of their power from entities with sophisticated energy and FTR trading strategies, selling the output of power plants built “on spec” to LMP markets. In the real world, the collapse of the marketer/merchant sectors has demonstrated that regulatory policies cannot count on merchant generators, responding to efficient price signals, to build generation and fund transmission to bid into the day-ahead and real-time market, decongest the transmission system, ameliorate market power in load pockets, and ensure resource adequacy generation. At best, this approach will produce a boom-and-bust cycle of plant development, price volatility, and periodic waves of marketer and LLC bankruptcies.

The experience of the last several years has demonstrated that the key to financing and constructing new generation is to create an environment that allows LSEs to make long-term commitments to purchase the output of new plants at stable, predictable prices. Market designs that undermine such investments and force LSEs to pay spot market prices, regardless of their portfolio planning, are a step in the wrong direction.

12. *How has restructuring of incumbent utility operations and the introduction of competitive retail markets in retail choice states affected participation in regional wholesale markets? Has the introduction of retail markets affected the level of long-term contracting in wholesale markets?*

Retail choice regimes are claimed to limit the ability of some LSEs to enter into long-term contracts, justifying the abrogation of long-term rights in order to increase market liquidity, and creating financing issues for generation and a claimed need to develop costly, complicated organized capacity markets. Even in states that have adopted retail competition, however, some LSEs, including public power systems and rural electric cooperatives, still have an obligation to serve. These LSEs must have access to the full set of tools needed to assemble cost-effective, fuel-diverse power supply portfolios over the long term. The argument that they should be denied those tools in order to maximize the availability of short-term rights is tantamount to saying, in an Order 888 world, that a transmission provider should not be able to grant long-term firm transmission service, or accept long-term resource designations for its native load or a network customer, because that will tie up the short-term capacity otherwise available to those who choose not to make a long-term commitment. In a capital-intensive industry that requires long-term contracts, a lowest-common-denominator policy approach is bad policy and contrary to the goals of encouraging the construction of new clean coal, nuclear, and renewable resources.<sup>34</sup>

Concerns have also been voiced about the ability of LSEs in retail choice states to support long-term contracts, because of changing load obligations.<sup>35</sup> Not surprisingly, RTO regions that include retail choice have also adopted ICAP and locational ICAP regimes.

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<sup>34</sup> TAPS' *Long-Term Transmission Rights Comments* at 42.

<sup>35</sup> *Compensation for Generating Units Subject to Local Market Power Mitigation in Bid-Based Markets*, Docket No. PL04-2 000, Tr. at 113-14, 195-96.

Unfortunately, LSEs such as TAPS members that are able to provide such revenue guarantees to generation through long-term contracts, get swept into these organized ICAP markets and are forced to purchase the ICAP product, as well as bear the high administrative expenses of the RTO's operating these "markets."<sup>36</sup> The ability of LSEs to bid their contracted for (or owned) generation in the ICAP market is not a satisfactory hedge where FTRs are not adequate to overcome the locational pricing differences found in the more recent ICAP market designs or where complicated performance measures claw-back revenues due to LSEs that stepped up to the plate to ensure that they had iron in the ground. At minimum, LSEs that have sufficient generation should be allowed to opt out of organized ICAP markets.<sup>37</sup>

13. *Please describe instances in which competition has resulted in relatively higher prices or lower reliability in a specific regional market.*

TAPS describes its members recent discouraging experiences in wholesale markets in response to Question II.A.5. above. In addition, a recent California PUC Opinion on Resource Adequacy Requirements concluded that the standard form contracts which are commonly in use, including the EEI "Firm LD" contract, cannot assure adequacy or reliability because there currently is no tie to specific generation sources or assurance of deliverability.<sup>38</sup>

*B. Generation Ownership:*

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<sup>36</sup> "Market" is likely a misnomer for ICAP regimes, the most recent versions of which rely upon administratively determined demand curves designed to allow recovery of an administratively determined cost of entry by an imaginary combustion turbine. See proposals pending in *Devon Power, LLC*, FERC Docket No. ER03-563-030, *PJM Interconnection, LLC*, FERC Docket Nos. ER05-1410-000 and EL05-148-000, and approved, *New York Independent System Operator, Inc.*, 111 F.E.R.C. ¶ 61,117, *reh'g denied*, 112 F.E.R.C. ¶ 61,283 (2005).

<sup>37</sup> TAPS members support resource adequacy requirements tied to assurance of long-term transmission rights (whether physical or financial) and a robust transmission planning model (as discussed in the TAPS White Paper (Attachment 1) and TAPS' Balanced Principles for Planning and Expansion (Attachment 2)). However, based on what we have seen of the LICAP proposals, we are wary and worried.

<sup>38</sup> Order Instituting Rulemaking to Promote Policy and Program Coordination and Integration in Electric Utility Resource Planning, Rulemaking 04-04-003 (Oct. 27, 2005), *available at*: [http://www.epuc.ca.gov/word\\_pdf/FINAL\\_DECISION/50731.pdf](http://www.epuc.ca.gov/word_pdf/FINAL_DECISION/50731.pdf).

4. *How much existing capacity has been sold or transferred to utilities and converted to rate-based assets? Of those how many were previously affiliated with a utility and how many were purchased from other entities?*

While TAPS has not done a quantitative study, the growing list of FERC cases involving such transfers indicates that utility purchases of merchant generation is growing. These cases include:

- *Cinergy Services, Inc.*, 102 F.E.R.C. ¶ 61,128 (2003), *reh'g denied*, 108 F.E.R.C. ¶ 61,250 (2004).
- *Ameren Energy Generating Co., et al.*, 108 F.E.R.C. ¶ 61,081 (2004).
- *Perryville Energy Partners, LLC*, 109 F.E.R.C. ¶ 61,019 (2004), *reh'g denied*, 111 F.E.R.C. ¶ 61,006 (2005) (*Entergy*).
- *Oklahoma Gas & Electric Co., et al.*, 108 F.E.R.C. ¶ 61,004 (2004), *reh'g denied*, 111 F.E.R.C. ¶ 61,075 (2005).

Frequently, IPPs are forced to sell to vertically integrated incumbents, because those incumbents' inadequate transmission infrastructure prevents generators from selling to willing LSEs. TAPS member LUS' experience with being unable to access some of the 18,000 MW of IPP generation connected to the Entergy system illustrates the problem. *See* Response to Question II.A.4. above. In many cases, the constraints arise from failed transmission planning and inadequate transmission infrastructure, which augment the market power of dominant buying and selling firms. Where the dominant firm is the only buyer in town, generators have no or few potential customers, if the firm chooses to buy from its own affiliated generation or to build its own plant. Where the dominant firm is the only seller in town, it is able to name its prices for sales to other LSEs meeting all or part of their customers' needs through purchased power.

Transmission sufficient to allow willing buyers and sellers to contract economically and reliably is an obvious and effective solution to these market power problems. Rules regarding

competitive solicitations and utility acquisition practices<sup>39</sup> are band-aids for the underlying absence of competitive wholesale markets where many buyers and can reach many sellers. Whatever the merits of a well-run competitive solicitation, it is only likely to solve the problem of the generator who happens to win a contract. The losing bidders still need someone to whom they can sell their output. LSEs other than the dominant firm are potential markets for losing bidders, but inadequate transmission can block otherwise economic deals. Thus, without transmission adequacy, workably competitive generation markets are an impossible dream.

C. *Generation Adequacy:*

3. *What role does the ability to enter into long-term contracts play in financing new generation projects?*

See response to Question II.A.8. above.

6. *What difficulties, if any, have developers of new generation facilities encountered in bringing generation supply to market? (E.g., difficulties in financing, siting, permitting, licensing, interconnection, transmission access, fuel supply). What are ways to improve the process?*

See responses to Question Nos. II.A.4. and II.A.8. above.

10. *What incentives or responsibilities do load serving utilities have to maintain adequate reserve capacity?*

As noted in response to Question II.A.12., LSEs, including TAPS members, are often subject to state and regional reliability standards and are responsible to their citizens/customers to maintain adequate generation. During the 2000-2001 California Market Meltdown, the state's municipal utilities were fully resourced and had the generation necessary to keep their lights on

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<sup>39</sup> *Ameren Energy Generating Co., et al.*, 108 F.E.R.C. ¶ 61,081 (2004); *Allegheny Energy Supply Co.*, 108 F.E.R.C. ¶ 61,082 (2004).

(plus reserves), while the IOUs had developed a practice of relying entirely on the spot market and even then underscheduling their load for the next day by some 40% in order to game the market to reduce costs.

11. *How can competitive markets assure adequacy of generation supply? How is reserve sharing to meet state or regional generation adequacy standards accomplished in competitive markets? How can other institutions/market processes provide an effective substitute for reserve sharing?*

The “market” is not an adequate substitute for reserve sharing. Reserve sharing has been an important means for utilities to provide reliable service at reasonable cost, by addressing the needs of all utilities to perform maintenance while meeting the demands of their load.

[S]mall utilities can construct and operate large, economically efficient plants without experiencing an unmanageable rise in required reserve levels only if they have suitable coordination arrangements. . . . [R]efusals to coordinate . . . have a two-pronged anticompetitive effect.

*In the Matter of Consumers Power Co.* (Midland Plant, Units 1 and 2), 6 NRC 892, 1061-62 (1977). FERC and the courts have similarly recognized that reserve-sharing services are important to small systems.<sup>40</sup> For this reason, the Nuclear Regulatory Commission imposed obligations to provide coordination services in license conditions designed to prevent situations inconsistent with the antitrust laws.

The mutual reinsurance concepts on which reserve sharing is based must not be discarded with the move into more organized markets and greater reliance on competition. To the contrary, the effectiveness of these markets can be enhanced by building in and on traditional reserve sharing institutions and mechanisms that effectively hedge the risk of an outage and

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<sup>40</sup> *Mid-Continent Area Power Pool Agreement*, 58 FPC 2622, 2635-36, *reh'g denied*, 59 FPC 1651 (1977), *aff'd*, *Central Iowa Power Coop. v. FERC*, 606 F.2d 1156, 1172 (D.C. Cir. 1979). *See also Gainesville Utils. Dept. v. Florida Power Corp.*, 402 U.S. 515 (1971).

provide needed generation investment that ensures there are capacity resources to bid into spot energy markets. The goal should be to incorporate and protect bilateral reserve sharing arrangements, including through long-term transmission rights.

Even Entergy, which withdrew from SPP to avoid having to commit its transmission to others and joined SERC instead, maintained its membership in the SPP reserve sharing pool because of the huge savings. If one of the largest vertically integrated utilities in the country, with its own massive fleet of generation sources among which to spread risk, finds it necessary to reduce its risks and costs by maintaining its membership in the SPP reserve sharing pool, the need for risk reduction for smaller entities will be even greater.

*D. Transmission Investment and Regulation*

- 1. What are the most important factors that affect whether transmission will be built? What are ways to improve the process? What difficulties have transmission owners had in upgrading or building new transmission facilities? What are the prospects for merchant transmission?*

TAPS's June 2004 White Paper, "Effective Solutions for Getting Needed Transmission Built at Reasonable Cost," Attachment 1 to these comments, addresses the factors that are preventing the construction of needed transmission as well as solutions to getting that transmission built. Over the past twenty years, investment in transmission has fallen increasingly behind previous levels and has failed to keep pace with industry growth. Reasons for this failure to invest include regulatory uncertainty, unpopularity of siting, retail rate freezes, cost responsibility disputes, internal competition for capital in vertically integrated utilities, and the unwillingness of vertically integrated transmission owners to expose their generation to competition. The White Paper proposes structural changes and regulatory actions to remedy these problems.

One successful structural solution is the “transmission-only” company, open to ownership by all LSEs that depend upon the transmission grid. Such a company can grow its business only by investing in transmission and is not burdened by the internal competition for capital that occurs within vertically integrated, investor-owned utilities. Nor is a transmission-only company faced with the disincentive to construct that is present for transmission owners that own generation. Current examples of transmission-only companies include the American Transmission Company in Wisconsin and the Vermont Electric Power Company. Another successful structural model is the shared or joint system. By agreement, the transmission facilities of two or more LSEs are combined into a single system. Each participating LSE has the obligation to invest in new transmission facilities on a proportionate basis. Successful examples of this approach are in effect in Georgia, Indiana and the Upper Midwest. While open to all LSEs in an area, these models expand sources of capital, reduce regulatory conflict and facilitate siting through joint planning, ownership and operation of the transmission grid.

In addition to working with other policymakers to strongly encourage inclusive stand-alone transmission companies and shared systems, regulators should take a number of other actions that will facilitate needed grid investment, while minimizing the cost to consumers. They should:

1. Provide for current recovery of reasonable pre-certification expenses, and include construction-work-in-progress (“CWIP”) in rate base, to reduce risk and improve cash flow, without increasing life-cycle costs to customers;
2. Align transmission costs and revenues through formula rates to eliminate regulatory lag;
3. Set equity returns and require use of capital structures that reflect regulated transmission’s low-risk profile;
4. Develop new financing strategies to access investors seeking the stable, annuity-like returns that transmission can provide;

5. Require bidding of the capital requirements for new major improvements (debt and equity return, capital structure, depreciation and taxes) where a vertically integrated transmission owner refuses to build without an above-market “incentive” return or rates reflecting accelerated depreciation;
6. Allocate the cost of high voltage, backbone transmission on a regional basis to spread the cost burden and match cost responsibility to the broad regional benefits that will be realized from a robust grid;<sup>41</sup>
7. Require regional, least-cost transmission planning for major additions; and
8. Set performance-based rates that reward reductions in the cost of congestion, responsiveness to customer needs, inclusive planning, and LSE investment rights, while holding transmission owners accountable for poor performance.

The foregoing targeted solutions, which are developed in greater detail in the White Paper, are preferable to, and more effective than, the above-market equity returns and accelerated depreciation rate incentives some investor-owned transmission owners are seeking, or relying on “participant funding” to shift the cost – but not the benefit – of network additions away from transmission owners. These initiatives will not get needed transmission built on a cost-effective basis, and in some cases will mean that needed transmission is not constructed at all. Further, elevated returns and accelerated depreciation will burden consumers, adding to state resistance to transmission additions, while injuring competitive generation markets and doing little to address the real risks associated with transmission investment. Participant funding, which depends on individual market participants to fund transmission upgrades, is likely to delay needed construction and create new vested interests in maintaining congestion, instead of efficiently expanding the grid to reliably meet the needs of all users and providing the infrastructure required for vigorously competitive generation markets.

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<sup>41</sup> See also *TAPS Balanced Principles for Planning and Expansion* (July 17, 2002) (Attachment 2 to the Comments), which identifies categories of expansions that should be made and funded by roll-in (preferably using the TRANSLink rate design (described in n.55 below)), but leaving some room for participant funding in the RTO context for integration of new generators in limited circumstances. Under TAPS’ approach, network upgrades required to provide all loads reasonable access to the market would be rolled in.

2. *Over the past 10 years, what have been the trends in investments in transmission by utilities by state or region? Are there any prevailing patterns in transmission investments in upgrades and replacement of existing plant versus new lines, interconnections, automation? Have these patterns of investment shifted over this period? Are there any projected changes in patterns of transmission investment over the next 5 years?*

The TAPS White Paper, summarized in response to Question D.1., explores recent trends in transmission (non)investment. It describes how municipally and cooperatively owned LSEs have been willing to bring their capital to the transmission table, particularly in the Upper Midwest, Indiana and Georgia. However, efforts to expand inclusive transmission ownership models to other parts of the country have thus far not borne fruit, even where the vertically integrated transmission owner is in dire need of capital. For example, TAPS members, Lafayette Utilities System, Clarksdale, MS, and the Missouri Joint Municipal Electric Utility Commission, recently wrote to Entergy Corp. offering to invest in transmission to re-build Entergy's Katrina-devastated transmission system. Entergy has not exactly jumped at the offer, though it continues to pursue a half-billion dollar federal bail-out.<sup>42</sup>

3. *How are transmission needs of merchant generators and renewable energy projects included in regional or utility transmission planning and upgrades?*

As part of FERC's inquiry into the State of Wind Energy in Wholesale Electricity Markets, Docket No. AD04-13-000, TAPS examined the transmission needs of wind energy and concluded that they are, in many respects, identical to the kinds of transmission planning and

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<sup>42</sup> These municipal systems' offers are Attachment 1 to TAPS' November 22, 2005 Comments in FERC's Notice of Inquiry on the Order No. 888 OATT, Preventing Undue Discrimination and Preference in Transmission Services, Docket No. RM05-25-000, available at <http://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=10887678>.

long-term rights needs of LSEs desiring to make long-term investment in fuel diverse generation resources.<sup>43</sup> Specifically, TAPS identified as key issues:

- ❑ strengthening the grid, by promoting grid investment, so that it can accommodate and promote investment in all network resources, including wind;
- ❑ providing the long-term rights to delivery at a predictable cost that are necessary to promote investment in and secure financing of high installed cost resources;
- ❑ adopting reasonable approaches to recognize and credit the capacity provided by wind generation; and
- ❑ eliminating the current undue discrimination against transmission dependent utilities (and especially those with wind resources) with regard to the ancillary services, particularly unavoidable energy imbalance penalties.

However, TAPS urged against hasty incorporation of new services, ostensibly tailored to the needs of wind power, because of grave danger of significant unintended consequences on a grid that all users must share.<sup>44</sup>

4. *How has the establishment of Regional Transmission Organizations (RTOs) changed transmission operations, transmission planning, and investment patterns?*

On the positive side, RTOs have taken control of the operation of transmission systems, as well as (in some instances) direction of the planning function, out of the hands of vertically integrated utilities, thus addressing, in part, the temptation to maintain a weak grid to fend off meaningful generation competition. On the other hand, RTO-led planning is not producing

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<sup>43</sup> See Docket No. AD04-13-000, Statement of John A. Krajewski, P.E. for the December 1 Technical Conference, available at <http://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=10323050>, and January 28, 2005 Post-Technical Conference Comments of the Transmission Access Policy Study Group, available at <http://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=10388839>.

<sup>44</sup> See April 13, 2005 TAPS Post-Workshop Comments in Potential New Wholesale Electric Transmission Services, Docket Nos. RM05-7 and AD04-13, available at <http://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=10493358>. TAPS has also filed comments regarding the barriers posed by non-comparable imbalance charges. See TAPS Pre-Technical Conference Comments in *Assessing the State of Wind Energy in Wholesale Electricity Markets*, Docket No. AD04-13-000 (as filed Dec. 23, 2004) (providing concrete illustration of the severe and discriminatory impact of imbalance penalty), available at <http://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=10347542>.

results for the American consumer. The root of the problem is the false dichotomy between reliability upgrades, where costs are rolled into rate base and spread broadly, and economic upgrades, where costs are directly assigned to a specific market participant under the mistaken belief that only it benefits from the upgrade. Even PJM has conceded that the current LMP regimen, which utilizes the reliability/economic upgrade distinction, is producing “disappointing results.”<sup>45</sup>

Do we want a “minimalist” transmission grid that essentially serves as an “add-on” facilitating the reliable movement of power from generation sited close to load? In other words, should the transmission system merely be a facilitator for a model based on local generation? Or are we looking for a strong transmission system that, by its design, links distant generation to load in order to address both economics and reliability and accommodate an array of generation alternatives from which load can choose? The “rules of the road” and the costs to build one system versus another are vastly different....

In many ways, the Energy Policy Act of 1992 answered this question in favor of the strong superhighway to support a competitive generation industry.... Assuming that we wish a strong transmission system to provide load with many options, we believe a new set of “building blocks” is needed.<sup>46</sup>

EPAAct 2005, with its provision for backstop federal siting of national interest transmission corridors (where constraints and congestion adversely affect consumers),<sup>47</sup> its directive that the Commission exercise its authority to facilitate the expansion of the grid to meet the reasonable needs of load-serving entities,<sup>48</sup> and its provision for incentive/performance-based rates to

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<sup>45</sup> Written Remarks of Audrey Zibelman, PJM’s Executive Vice President, at the April 22, 2005 Transmission Investment Technical Conference, *Transmission Independence and Investment*, Docket Nos. AD05-5-000 and PL03-1-000, at 5, available at <http://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=10507109>.

<sup>46</sup> *Id.*

<sup>47</sup> EPAAct 2005 § 1221; FPA § 216.

<sup>48</sup> EPAAct 2005 § 1233; FPA § 217(b)(4).

benefit consumers by ensuring reliability and reducing delivered power cost by reducing transmission congestion<sup>49</sup> point toward affirmative steps to create the robust grid that supports competitive markets, rather than relying on LMP signals to induce “market solutions” or ration the use of an increasingly constrained system. Congress has witnessed the high and growing congestion costs borne by consumers, even in RTO markets, and has made clear that this is not what it wants.

One of the consequences of the current RTO approaches is a dangerous over-reliance on gas-fired generation. As described by PJM’s Zibelman, the current regime produces a minimalist grid, meaning that loads must resort to new generation that can be sited close by, *i.e.* natural gas-fired plants. Nearly 94% of new generation runs on natural gas at a time when natural gas prices are sky-high.<sup>50</sup> The country needs fuel diversity for both economic and reliability reasons,<sup>51</sup> but that goal will not be achieved if loads cannot access the kinds of generation that often must be sited in more remote areas, such as coal-fired, nuclear and wind.

5. *Within a region or RTO, is there a different process for transmission upgrades that are not required for reliability but would increase access to lower priced power in areas with economic congestion?*

*See response to Question II.D.4. above.*

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<sup>49</sup> EPAAct 2005, § 1241; FPA§ 219.

<sup>50</sup> *See* TAPS White Paper at 5-6.

<sup>51</sup> For example, ISO-New England has warned about the possibility of tight electricity supplies this winter, not because of inadequate capacity overall but because so much of New England’s capacity is fired by natural gas. Many gas-fired generators rely on contracts that can be interrupted when temperatures plunge, thus increasing demand for home-heating. Electricity demand also tends to increase to record levels during such cold snaps. *See* ISO-New England Press Release, *ISO New England Assessment Indicates Electricity Demand Could Set New Winter Record* (Nov. 16, 2005), *available at*: [http://www.iso-ne.com/nwsiss/pr/2005/final\\_winter\\_05\\_06\\_outlook.pdf](http://www.iso-ne.com/nwsiss/pr/2005/final_winter_05_06_outlook.pdf). In January 2004, New England faced emergency electricity conditions when some gas fired generators with *firm* gas transport contracts opted to sell their fuel into spot gas markets instead of using it to generate electricity. *See* ISO-New England, *Final Report on Electricity Supply Conditions in New England During the January 14 - 16, 2004 “Cold Snap,”* (Oct. 12, 2004), *available at*: [http://www.iso-ne.com/pubs/spcl\\_rpts/2004/cld\\_snp\\_rpt/1\\_Final\\_Report\\_On\\_January\\_2004\\_Cold\\_Snap.pdf](http://www.iso-ne.com/pubs/spcl_rpts/2004/cld_snp_rpt/1_Final_Report_On_January_2004_Cold_Snap.pdf).

6. *In the absence of RTOs, how is transmission planning, siting, and construction for regional needs coordinated among utilities, generators, and State regulators? What challenges do transmission owners face upgrading or building new transmission facilities?*

Although some high level regional planning exists (e.g., MAPP), there is little meaningful coordination on a regional basis in the absence of RTOs. Individual systems control the process, and even then fail to live up to the planning expectations imposed upon them by Order 888's OATT.<sup>52</sup> Individual transmission owners should be required to engage in a joint planning and expansion process with their network customers, or better yet, on an inclusive regional basis.<sup>53</sup> The key is for the process to be open and transparent, with customers playing a meaningful role. Joint planning models that work are already in place, as described in the attached TAPS White Paper.<sup>54</sup> The aim should be a grid that permits wholesale customers reasonable access to competitive markets, rather than one that minimally meets reliability requirements.

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<sup>52</sup> See November 22, 2005 Comments of the Transmission Access Policy Study Group, *Preventing Undue Discrimination and Preference in Transmission Services*, FERC Docket No. RM05-25-000, at 11-19, available at <http://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=10887678>.

<sup>53</sup> While not "regional," the planning process recently developed in North Carolina at least moves beyond single-system planning. Concerned about the transmission issues in North Carolina, the North Carolina Utilities Commission ("NCUC") initiated a series of stakeholder meetings to "become better informed about the status of the electric transmission facilities in North Carolina and the potential transmission-related issues that might arise in the future" and to "identify any specific electric transmission issues that have the potential to impact the ability of transmission dependent load-serving entities to provide reliable and adequate service to their retail customers." Notice of May 24, 2005 Transmission Stakeholders' Meeting, available at <http://www.ncuc.commerce.state.nc.us/transmission/may24notice.pdf> (last viewed Nov. 20, 2005). The NCUC-sponsored process led to the recently executed "North Carolina Load Serving Entities' Transmission Planning Participation Agreement" among Electricities of North Carolina (a TAPS member), NCEMC, PEC, and Duke Power, which established a joint transmission planning process.

<sup>54</sup> See Appendix to TAPS White Paper (Attachment 1 hereto) and TAPS' Balanced Principles (Attachment 2 hereto).

TAPS also endorses regional rates that reflect the characteristics of high-voltage, “backbone” transmission lines.<sup>55</sup> Spreading the costs of such lines across a region (rather than just locally) would match the broad regional benefits obtained, and reduce opposition from local consumers and state regulators.<sup>56</sup>

*E. Wholesale Market Transparency and Information*

2. *Is there sufficient timely and accurate publicly available information to assure that market participants can adequately assess the economics of proposed wholesale power transactions or assess the financial implications of self build versus competitive alternatives for generation supply?*

Present ISO and RTO policies prohibit the release of market information for many months, *e.g.*, 6 months in the case of current ISO/RTO policies.<sup>57</sup> The current asymmetry of information access favors sellers over purchasers and encourages the unilateral exercise of market power. Large market participants have a substantial competitive advantage in market knowledge over smaller, load-serving entities or new entrants. This uneven playing field may discourage entry. In addition, the information asymmetry produces the perverse result that entities with greater knowledge are able to figure out how to game the system and to develop strategies that allow them to exercise market power, while the lack of market transparency simultaneously allows them to shield their activities from scrutiny.

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<sup>55</sup> An example of such a rate is the so-called TRANSLink rate. It is described in the Commission’s April 25, 2002 Order in *TRANSLink Transmission Co., L.L.C.*, 99 F.E.R.C. ¶ 61,106, at 61,465-68 (2002), and its December 19, 2002 Order in *TRANSLink Development Co., L.L.C.*, 101 F.E.R.C. ¶ 61,316, PP 15-24 (2002).

<sup>56</sup> Depending upon the degree of grid integration, FERC might assign the costs of major backbone facilities across all regional loads even outside the RTO context. *See Ft. Pierce Utils. Auth. v. FERC*, 730 F.2d 778, 783-85 (D.C. Cir. 1984).

<sup>57</sup> A six-month lapse has been authorized by FERC for ISO/RTO release of data. *Central Hudson Gas & Electric Corp.*, 86 F.E.R.C. ¶ 61,062, at 61,224 (1999); *PJM Interconnection, L.L.C.*, 86 F.E.R.C. ¶ 61,247, at 61,890 (1999); *San Diego Gas & Elec. Co. v. Sellers of Energy and Ancillary Serv.*, 95 F.E.R.C. ¶ 61,115, at 61,364 (2001); *NSTAR Services Co. v. New England Power Pool*, 92 F.E.R.C. ¶ 61,065, at 61,201 (2000), *clarified*, 92 F.E.R.C. ¶ 61,254 (2000). Further, TAPS members report that, at least in ISO-New England, the data are so devoid of useful information as to be meaningless.

3. *How can any information deficits be remedied to improve the utility of market information? Are there any competitive risks associated with greater transparency of prices or of other information about market participants?*

When it comes to market data, secrecy should not be assumed. There are successful models for making information, including bid-offer data, available on a real or close-to-real time basis.<sup>58</sup> In other functioning, competitive electricity markets, market data is released routinely, and without the confidentiality protections that FERC has required or approved to date. In the Australian National Electricity Market, for example, generating unit bid data is available on a next-day basis.<sup>59</sup> Likewise, the Balancing Mechanism Reporting System (“BMRS”) website for the England and Wales market provides near real-time and historical data — including bid-offer data — on the National Grid Company’s balancing of power flows in the electricity transmission system in England and Wales.<sup>60</sup> Data disclosures have not caused those markets to collapse.<sup>61</sup> On the contrary, competitive markets thrive on information, not secrecy. On the New York Stock Exchange, trade information is immediately available, and actions are traceable to those commanding the activity.

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<sup>58</sup> In other contexts, such as securities regulation, transparency is favored because it breeds investor confidence, strengthens capital markets and leads to economic growth. See Claire Moore Dickerson, *Crisis in Confidence: Corporate Governance and Professional Ethics Post-Enron*, 35 CONN. L. REV. 1035, 1052 (2003) (citing Bernard S. Black, *The Legal and Institutional Preconditions for Strong Securities Markets*, 48 UCLA L. REV. 781, 786-87, 835-38 (2001) and Joel Seligman, *The Historical Need for a Mandatory Corporate Disclosure System*, 9 J. CORP. L. 1 (1983)).

<sup>59</sup> This data is found at <http://www.nemmco.com.au/data/csv.htm>. (last visited November 28, 2005).

<sup>60</sup> On the BMRS website (<http://www.bmreports.com>), a wide range of data, including bid-offer data for each BM Unit, can be retrieved at [http://www.bmreports.com/bwx\\_reporting.htm](http://www.bmreports.com/bwx_reporting.htm) (last visited November 29, 2005).

<sup>61</sup> See, e.g., National Audit Office (U.K.), *THE NEW ELECTRICITY TRADING ARRANGEMENTS IN ENGLAND AND WALES*, Report by the Comptroller and Auditor General (9 May 2003), available at [http://www.nao.org.uk/publications/nao\\_reports/02-03/0203624.pdf](http://www.nao.org.uk/publications/nao_reports/02-03/0203624.pdf) (last viewed November 28, 2005).

While regularized access to sellers' "trading books" may not be necessary,<sup>62</sup> the size and complexity of bulk power markets today and in the future require a much greater level of information reporting and disclosure than in the past. At minimum, we urge the following steps towards greater transparency.

- **Bid and Offer information, including for FTR bids, should be released no more than one week after the real time market clears.** The greatest danger to LMP market design involves generators that derive market power from their control of multiple resources, because the intellectual foundation for the single-price auction model assumes that each offeror owns only one asset.<sup>63</sup> Large generation-portfolio holders know their offers for each of their multiple resources. The best way to police their offerings and level the competitive playing field is to release everyone's offer information as soon as possible, and certainly within one season after the market clears.
- **Real-time generator status information, which is already available through costly private sources, should be made public.** Sources like Genscape already sell information on generator operating status. Consequently, those which would use such information to manipulate markets or for other improper purposes<sup>64</sup> can already get it. Allowing RTOs to make it available for free would have the salutary effect of enabling smaller market participants to compete on a level playing field, and enabling them and low-budget consumer representatives (e.g., official state consumer advocates) to assist with market monitoring.

While some concern that information transparency might support coordinated interaction (e.g., collusion) on the part of market participants is legitimate, these concerns do not justify withholding non-confidential data (or delaying its release by three or six months) from market participants. The Task Force must resist over-emphasizing the role that information transparency can play in supporting coordinated interaction. From antitrust law and economics,

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<sup>62</sup> Where appropriate, such access should not be ruled out.

<sup>63</sup> See Robert C. McDiarmid, Lisa G. Dowden, and Daniel I. Davidson, *Revoke the Nobel Prize? Recognize the Limitations of Theory? Or Grant a License to Steal?* 14 Elec. J. 11 (Jan.-Feb. 2001).

<sup>64</sup> Given the public availability of Genscape information and other means of acquiring information on a target plant's operating status, we doubt that a homeland security basis for keeping such information non-public exists. If that case can be made, however, the proper response is to make the generator status information available to all industry stakeholders which demonstrate their bona fides as North American market participants. Cf. *Critical Energy Infrastructure Information*, 104 F.E.R.C. ¶ 61,106, P7 (2003) ("The Commission encourages these entities [RTOs and others] to provide information to legitimate requesters").

we know concentration levels and ease of entry are leading factors affecting the ability of firms to collude. Other factors, such as market transparency, firm size, product homogeneity or heterogeneity and prior evidence of coordinated activity, can play a role in specific cases, but are far from dispositive in all circumstances.<sup>65</sup> Moreover, transparency rules can be refined to keep confidential, or delay the release of, information that is the most sensitive and otherwise not available.

### CONCLUSION

TAPS thanks the Task Force for the opportunity to respond to its questions.

Respectfully submitted,

*/s/ Mark S. Hegedus*

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Robert C. McDiarmid  
Cynthia S. Bogorad  
Mark S. Hegedus

Attorneys for  
Transmission Access Policy Study Group

Law Offices of:  
Spiegel & McDiarmid  
1333 New Hampshire Avenue, NW  
Washington, DC 20036  
(202) 879-4000

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<sup>65</sup> See Margaret C. Levenstein and Valerie Y. Suslow, *What Determines Cartel Success?* University of Michigan Business School Working Paper No. 02-001 (January 2002), available at [http://papers.ssrn.com/sol3/delivery.cfm/SSRN\\_ID299415\\_code020210670.pdf?abstractid=299415](http://papers.ssrn.com/sol3/delivery.cfm/SSRN_ID299415_code020210670.pdf?abstractid=299415) (last visited May 6, 2004) and forthcoming in *How Cartels Endure and How They Fail: Studies of Industrial Collusion*, Peter Grossman, ed.); see also *Horizontal Merger Guidelines*, §§ 2.11, 2.12; *In re High Fructose Corn Syrup Antitrust Litigation*, 295 F.3d 651 (7<sup>th</sup> Cir. 2002); *Federal Trade Comm'n v. Elders Grain, Inc.*, 868 F.2d 901 (7<sup>th</sup> Cir. 1989); *Hosp. Corp. of America v. Federal Trade Comm'n*, 807 F.2d 1381 (7<sup>th</sup> Cir. 1986).