**UNITED STATES OF AMERICA**
**BEFORE THE**
**FEDERAL ENERGY REGULATORY COMMISSION**

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| **PJM Interconnection, L.L.C.** | ) | **Docket No. EL08-47-000** |
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# COMMENTS OF THE INDEPENDENT MARKET MONITOR FOR PJM

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Pursuant to Rule 211 of the Commission's Rules and Regulations,[1] Monitoring Analytics, LLC, in its capacity as the Independent Market Monitor for PJM[2] ("Market Monitor"), respectfully submits these comments in the Commission's investigation "to consider the continued justness and reasonableness of PJM's existing market power screen."[3] The Market Monitor also endeavors to respond to the Commission's previous inquiry into this matter that was concluded by settlement.[4]

The Market Monitor welcomes this opportunity to explain why the Three Pivotal Supplier ("TPS") test allows for the suspension of mitigation in the energy markets during hours when competition is adequate to ensure competitive prices, but generally leaves mitigation in place when non-competitive prices could result. The Market

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1 18 CFR § 385.211 (2008).

2 PJM Interconnection, L.L.C., a FERC approved Regional Transmission Organization. Capitalized terms not otherwise defined herein shall have the same meaning as defined in the PJM Open Access Transmission Tariff ("OATT") or the PJM Operating Agreement ("OA"). Citations to Schedule 1 of the OA omit parallel references to the Appendix to Attachment K of the OATT.

3 *PJM Interconnection, L.L.C.*, 123 FERC ¶61,169 at P 1, 59 & Ordering Para. (B) (2008) ("Investigation Order").

4 *PJM Interconnection, L.L.C.*, 112 FERC ¶61,031 at P 119 (2005) ("Specific issues that the hearing should address include: (a) the appropriateness and strengths/drawbacks of applying market power screening test in real-time; (b) whether the no-Three-Pivotal-Supplier Test is no more stringent than the screens approved by the Commission for granting market-based rate applications, and whether the tests produce similar results; (c) the implications of using a no-one or no-two pivotal supplier instead of the no-Three-Pivotal-Supplier Test; (e) whether the Commission market screens (such as the *AEP* screens) can be implemented in real-time; (f) whether tests more or less stringent than the *AEP* screens should be used to monitor and mitigate actual transactions in the market on a real time basis; and finally, (g) whether any of the above market power tests are likely to pass a supplier that should fail (i.e., incorrectly conclude that a supplier lacks market power when, in fact, it has market power) or fail a supplier that should pass (i.e., incorrectly conclude that a supplier has market power when, in fact, it lacks market power).")

Monitor here explains the functioning of the TPS test; compares the merits of the TPS test to certain alternatives; evaluates its stringency and the likelihood for false detections or failures to detect market power; explains the significance of three rather than one, two or four or more suppliers; and explains the relationship between the TPS test and the Commission's delivered price test. The Market Monitor also explains why the rules for mitigating market power in PJM do not, in the overall context of PJM's market design, interfere with appropriate incentives for new entry or otherwise inhibit PJM's long-term market price signals for the renewal of supply and the optimal allocation and location of new system investments.

The Market Monitor respectfully asks that the Commission confirm that the TPS test is a just, reasonable and non-discriminatory test for relaxing mitigation because it allows for the maximum reliance on competition to set prices and minimally interferes with the ability of the local market power rules to limit the exercise of the market power, and, moreover, that it does so in accordance with the Commission's tests for market power in other contexts and the Commission's preference that the organized markets employ wherever possible transparent, automatic, and non-discretionary market rules.

The Market Monitor seeks to address a more general concern that some perceive mitigation rules in the organized markets more as an afterthought than an essential component of a sound market design or merely as a short-term tool to carry the markets forward until they have fully matured. The more accurate view is that the electric industry remains a regulated industry, and the purpose of the Commission's reforms are to harness the forces of competition to spur the pursuit of greater efficiency and innovation and to lower wholesale electricity prices in fulfillment of its statutory mandates. It is important to recognize that under the conditions that will prevail in the energy markets for the foreseeable future, the potential exercise of market power, regardless of why it is exercised, is a serious threat to both of those objectives and must be vigorously contained. In order to ensure that the correct incentives are in place for new investment, it is necessary to ensure that all of the essential components of the overall design are in place and working well. Reliance on some "workable" or "tolerable" level of market power to do the job that the overall market design must accomplish is not a sustainable approach to market design.

# I. BACKGROUND

## A. The Goals of Industry Restructuring

In the approximately three decades that the Commission has pursued its reform of the electric industry, the Commission's principal rationale for its effort has been the promise that the forces of competition can improve efficiency in the industry and lower prices for wholesale electric power.[5] The Commission's goal is not to deregulate, or to

[5] *See Entergy Services, Inc.*, 58 FERC ¶61,234 at 61,753 (approving market-based rates for large wholesale power sales because rates set through competitive forces will result in cost savings to ratepayers); *Public Service Company of Indiana, Inc., Opinion No. 349*, 51 FERC ¶61,367 at 61,224–25 (stating that

free market participants to conduct themselves as though they operated in an unregulated industry.[6] It follows that to any extent that market power rather than competitive forces are permitted to set the wholesale price of electricity, anywhere or for any time, it compromises the fundamental objective of restructuring for competition.[7]

Few have stated this goal as powerfully as Chairman Kelliher in a speech delivered earlier this year:

> Our goal is perfect competition, textbook competition, competition that is so beautiful it would make an economist weep.
>
> I accept that we may not achieve that goal, and that perfect competition may not exist outside the textbook. In our pursuit of perfect competition we may fall short. But if so we will at least have achieved more perfect competition.
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> …
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> It is important to appreciate that U.S. wholesale competition policy was not inadvertent. It was a deliberate choice reflected in three major federal laws enacted over the past 30 years. The U.S. consciously embraced competition policy after the comprehensive

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competitive pricing improves efficiency by creating incentives for full utilization of existing capacity and innovation), cited by Joseph T. Kelliher, "Market Manipulation, Market Power, and the Authority of the Federal Energy Regulatory Commission, ENERGY L. J., Vol. 26, No. 1 at 9 n.40 (2005).

6 *See* Kelliher, Market Manipulation at 11 (2005) ("It is important to note that the Commission's policy was never intended to deregulate wholesale power markets. Notwithstanding great debates that have taken place in the United States over deregulation, our economic markets are not truly unregulated in the sense that they are completely free from rules.").

7 *Cf. Tejas Power Corp. v. FERC*, 908 F.2d 998, 1004 (D.C. Cir. 1990) ("In a competitive market, where neither buyer nor seller has significant market power, it is rational to assume that the terms of their voluntary exchange are reasonable, and specifically to infer that price is close to marginal cost, such that the seller makes only a normal return on its investment.")

> failure of traditional regulation to assure security of supply at reasonable cost.[8]

The Commission is correct to rely upon the forces of competition to achieve its goals of lower wholesale electric power costs because competitive markets impose discipline upon suppliers.[9] To prosper in this environment, a supplier must eliminate inefficiency and strive for continual innovation and improvement. In a competitive market, life is hard at the margin, and, from time-to-time, a competitor will fail. On the other side, many competitors will thrive.

The test of competition is not whether any particular resource is able to fully recover its costs. Competitive pricing does not guarantee that any or all suppliers will recover their costs for every investment and some suppliers may experience losses. Even cost-of-service regulation does not guarantee investors full recovery of costs. The only means to recover costs and earn profits is to become a more efficient supplier and take advantage of the opportunity posed by scarcity when it occurs. To the extent that market power is tolerated, consumers are denied the promise of the lowest long-run cost of electricity and the incentives for innovation and increased efficiency are muted. If, as in

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8 Statement of Chairman Joseph T. Kelliher State of US Competitive Wholesale Power Markets CERAWEEK 2008—Quest for Security: Strategies for a New Energy Future (February 15, 2008).

9 *See* ALFRED E. KAHN, THE ECONOMICS OF REGULATION: PRINCIPLES AND INSTITUTIONS at 326 (John Wiley & Sons, Inc. 1971) ("In a competitive industry, firms are motivated to produce efficiently—to find ways to cut production costs—by the hope of increased profits and by the fear that failure to keep costs low will cause more efficient firms to capture their customers by lowering price. In a regulated industry, the stick is usually unavailable.").

the case of the organized wholesale electricity markets at issue here, the Commission intends to "rely on the interaction of supply and demand in all instances to ensure that prices are competitive and thus just and reasonable,[10] then the preservation of competition and the attainment of just and reasonable prices are indistinguishable.

There has been some handwringing about the need to define "market power," and it appears from review of the discourse to date that the purpose of the discussion is to excuse the limited exercise of market power by imposing a formulation inapt to the structural issues that the electricity markets present.[11] The Commission has already defined market power correctly and succinctly as "the ability to raise price above competitive levels."[12] Notably, the Commission's formulation was in the context of its goals for the organized wholesale markets and, respecting that context, lacked temporal restrictions and irrelevant assumptions regarding lost sales.[13] A seller cannot make offers

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10 *See Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Design*, Notice of Proposed Rulemaking, 100 FERC ¶61,138 at P 390 (2002) ("Market Design Order").

11 *See* The Brattle Group, "Review of PJM's Market Power Mitigation Practices in Comparison to Other Organized Electricity Markets" at 15–19 (2007) ("Brattle Report").

12 Market Design Order at P 393. *See also* Steven Stoft, POWER SYSTEM ECONOMICS: DESIGNING MARKETS FOR ELECTRICITY at 317 (John Wiley & Sons, Inc., 2002) ("Market power is the ability to profit by moving the market away from the competitive level. According to economics, any ability to do this, no matter how fleeting or minimal, is still market power.").

13 Market Design Order at 393Indeed, the Commission took pains to distinguish its definition of market power with respect to electricity market design from that used in the context of natural gas pipelines, where it considered a "company's ability to raise prices significantly above a competitive level for a sustained period." *Id*. at 393 n.195. "In the Electric Industry," the Commission explained, "electricity price can spike for one hour or a few hours in ways that are less likely for natural gas pipeline transportation and storage rates, and the consequences can be quite different." *Id*.

above its incremental operating costs in the teeth of competition and expect to prosper. No useful purpose is served, and there is much mischief in, trying to redefine market power to excuse a failure to achieve the most competitive markets possible.[14]

The suggestion that it is the responsibility of regulators to understand the incentives of market participants when they are exercising market power would require an impossible and irrelevant task. The incentive clearly is to obtain higher prices than competitive conduct would otherwise obtain. Whatever the reason, motive or non-motive for an exercise of market power, only consumers' interest in competitively priced energy is compromised because market power will enable the supplier to reap the reward that competition would deny. For this reason, all discussion seeking to distinguish "abuse" of market power and its exercise is beside the point. The Commission's rules against market manipulation, the antitrust laws and the "citizen's watch" aspect of the market monitoring function, are all intended to combat the problem of abusive behavior. What is needed in real time are ex ante, automatic corrections to market power that require no accusation, apology or penury.

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14 See for example, PJM's characterization (at 4) of the TPSTF's agreement that "the ability to increase/decrease the market clearing price above/below competitive price level" may be the "simplest and clearest definition by which to evaluate potential market power mitigation mechanisms" but a definition that excused the exercise of market power for certain duration and/or magnitude would enable PJM to achieve "workably competitive" as opposed to almost "perfectly competitive" markets.

No one has explained why the PJM market design must accommodate anticompetitive behavior in order to obtain correct incentives. PJM concludes that under the alternative tests it has considered, "offers may escape mitigation but nonetheless be well above marginal-cost-based offer standard of competitive market behavior" and acknowledges that such tests "may provide suppliers a mechanism to gradually increase their offers above marginal costs but below the thresholds that would trigger mitigation," yet PJM is reluctant to defend the mitigation tool that PJM successfully developed and implemented precisely in order to avoid those anti-competitive results.[15] In an environment where RTOs increasingly are called upon to demonstrate their value to consumers in securing lower energy prices, RTO rules should be designed to ensure that the maximum power of competition is permitted to ensure that energy prices are as low as possible.[16]

PJM has a single market clearing price that pays all suppliers in a market the same price, whatever their own costs. In the context of a single market clearing price, the implications of the suggestion that some market power is acceptable are multiplied. Regulatory intervention in a competitive market aimed at ensuring that a relatively

15 Report of PJM Interconnection, L.L.C. filed in Docket No. EL08-47-000, et al. at 18–19 (September 5, 2008) ("PJM Report").

16 *See, e.g.*, Electricity Restructuring: FERC Could Take Additional Steps to Analyze Regional Transmission Organizations' Benefits and Performance, GAO Report to Committee on Homeland Security and Government Affairs, U.S. Senate (September 2008).

inefficient competitor is permitted to exercise market power will have consequences that affect all competitors, including the highly efficient ones who may already be quite profitable, and all customers. This is plainly uneconomic, socially costly and creates inappropriate and inefficient pricing signals for new investment. The concern about over-mitigation in the energy market is unsupported and misplaced. The Commission cannot properly rely upon competitive principles to set prices and then intervene in the market to ensure that certain marginal competitors recover their long-run costs, especially if that means continued neglect of other components of the market design, such as better scarcity pricing.[17]

In the case of local market power mitigation rules in PJM, the starting point is simplicity and accuracy, erring on the side of allowing market power of as much as ten percent. With the existing market power test, the rules impose substantially competitive results, no more, and perhaps less than desirable. Relaxation of the market power test will only increase the level of market power tolerated.

Although the purpose of the local market power rules is the prevention of the exercise of local market power, some have asserted that these rules have unintended consequences for the operation of the energy markets, including the suppression of incentives for investment, termed over mitigation.

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17 *See* 117 FERC ¶61,331 at P 77 citing *Devon Power, LLC*, 103 FERC ¶61,082 at P 29 (2003).

Over mitigation means either forcing a competitive outcome in the absence of market power or failing to provide appropriate incentives for investment by preventing generators from recovering their costs. If there is mitigation for local market power when it is not necessary, participants are forced to behave competitively. Thus, the cost of this mitigation is zero or very close to zero, so long as scarcity signals are not suppressed. Scarcity signals are not suppressed under the current market design. With the current RPM design, scarcity revenues are provided in the capacity market and to some extent, via the scarcity pricing provisions in the energy market.

There is no evidence of over mitigation in PJM markets. The introduction of the TPS test has resulted in less offer capping in the energy market. Participants can and do pass the TPS test when the test fails to find the presence of structural market power. The risk of under mitigation is substantially larger.

Local market power is always going to be an issue in the markets for wholesale electricity that exist in the context of transmission networks where constraints regularly create local markets with concentrated ownership. The Commission is well aware that the transmission system was not built to eliminate such constraints and that the infrastructure to support adequate participation of demand is not in place.[18] Mitigation is

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18 *See, e.g.*, *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, FERC Stats. & Regs. ¶31,241 at P 58 (2007), *order on reh'g*, Order No. 890-A, FERC Stats. & Regs. ¶31,261 (2007); *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008) (""The legacy systems constructed by vertically-integrated utilities prior to the adoption of Order No. 888 support 'only limited amounts of

a necessary and permanent feature of appropriately designed markets. The continuing need for mitigation is not symptomatic of any shortcomings in the design of PJM's markets and is an essential component of the Commission's goal to rebalance the use of regulation and competition in favor of increased reliance on competitive forces. It is not possible to achieve the Commission's objectives without sufficient mitigation in place.

### B. A Holistic View of PJM Markets

The design of PJM's markets must promote competitive outcomes. One of the Market Monitor's fundamental responsibilities is to identify actual or potential flaws in the market design.[19] The Market Monitor seeks to ensure that all of the disparate parts of PJM market design, including its mitigation component, will evolve together and produce the most efficient, integrated market design possible for the PJM Region.

Despite the conceptual attraction to some of an "energy-only" market for capacity, the energy market cannot, without a significant administrative component to its design, serve as the sole source of revenue to suppliers in a competitive energy market that is also subject to regulatory mandates for resource adequacy. In most industries, a temporary shortage of a product can be tolerated for a time as the market returns to equilibrium. In the electricity industry, a shortage of electric power supply is

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inter-regional power flows and transactions. Thus, existing systems cannot fully support all of society's goals for a modern electric-power system.'").

19 See OATT Attachment M § IV.B.2–4.

akin to a natural disaster, ostensibly not tolerated more than once in ten years, and in reality, never. Once a significant shortage occurs it could be months or years until the problem is rectified with new investment. Consequently, regulators demand a buffer amount of supply to be available significantly in excess of the total amount expected to be dispatched on even the peak days of the year. This reserve margin is, in effect, a mandated oversupply in the market that necessarily suppresses the price of energy below the equilibrium level that would prevail in its absence. Consequently, consumers must procure another product, capacity, the price of which is linked to but not identical to the price of energy.

The energy markets, including energy and associated markets for ancillary services, therefore, cannot be expected to provide a complete recovery of costs, and the stream of revenues available from the energy markets must be considered in conjunction with revenues received from the capacity market.

Many of the complaints about inadequate revenues from the energy markets have been misdirected. The problems were really with other components of PJM's market design. With the implementation of RPM, an augmented revenue stream sufficient to attract new investment and retain existing investment is now in place and mostly needs some tweaking in order to ensure, among other things, the accurate calculation of the net Cost of New Entry, the amplification and rationalization of locational pricing signals, and protection of the integrity of the capacity product. The scarcity pricing mechanism is the primary area still requiring additional reform, but the issue is the allocation of revenues between the RPM market and scarcity pricing rather than an issue of overall revenue adequacy, which has been addressed by the introduction of RPM.

The Commission should consider the reform of PJM's capacity market and the impending reform of the scarcity pricing rules as it evaluates the merits of the arguments raised against the inclusion of appropriate mitigation in the energy market. To the extent that the complaints about "over mitigation" were motivated by shortfalls in net revenue, even though not the result of mitigation, these complaints have been directly addressed by other reforms to PJM's market design.

### C. Procedural History

#### 1. Complaint Alleging Inadequate Compensation

The impetus for PJM to develop a local market power test was a complaint filed by Reliant Energy Mid-Atlantic Holdings, LLC ("Reliant"), on April 2, 2003. Prior to filing its complaint, Reliant had discussed with the MMU the development of a negotiated alternative cap, but Reliant did not provide any information on costs versus revenues for the ten units that it claimed were under compensated.[20] Eventually, the discussions turned instead to environmental policy based restrictions on its operations

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[20] Exhibit No. PJM-1 in Docket No. EL3-116-000 (Prepared Direct Testimony of Joseph E. Bowring) at 9 *l*.21–11 *l*.22 (filed April 28, 2003).

that limited the opportunity of Reliant's units to run during the more lucrative summer months. To address this issue, Reliant and the MMU agreed to an increased offer cap, which added an opportunity cost component to the otherwise applicable incremental operating cost plus ten-percent.[21] The agreement remained in effect from August 2001 to March 2003, when Reliant unilaterally terminated it before filing its complaint a few days later.[22]

During this time prior to the complaint, PJM established a Local Market Power Working Group ("LMPWG") to evaluate the existing rules and consider changes. The LMPWG developed an interim measure that provided, among other things, a $40 per MWh adder for any unit that was cost capped more than 80 percent of its run hours and operated for more than 200 hours.[23] Although this interim measure was never implemented, it was the genesis of the later proposal affording similar treatment to frequently mitigated units, discussed at greater length *infra* Section I.C.4.

Reliant did not limit the complaint to its own circumstances, but rather alleged "a significant design flaw in the existing PJM markets that results in a failure to appropriately reflect and compensate the Facilities that provide reliability service … in areas of PJM subject to chronic transmission constraints." Reliant sought to obtain from

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21 *Id*.

22 *Id*.

23 *See*, *e.g.*, July 9th Order at PP 5, 33.

the Commission approval of a special Formula Price Cap Mitigation Proposal (Proposal) that would increase revenues to its own facilities immediately.[24]

The Commission denied the complaint, finding that Reliant had not shown that "its units in PJM are not recovering fixed and variable costs," or that the local market power rules in PJM did not afford "a reasonable opportunity" to recover those costs, or that those rules "provide insufficient revenues … for new entry."[25] The Commission noted, however, the recognition of PJM and its MMU that "current provisions may not be the most appropriate mechanism for providing recovery to [must-run] units, particularly as they relate to scarcity pricing."[26] It therefore directed PJM to ensure that its rules provided appropriate compensation for units dispatched out of merit order and file by September 30, 2003, either appropriate revisions to its tariff or an analysis justifying its existing provisions.[27] The Commission also directed PJM to include detailed analysis of which plants are actually necessary for reliability and how it operated units such as Reliant's to support reliability in PJM.[28] Finally, the Commission urged PJM to take a holistic analytical approach in evaluating its market design and whether, taken

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24 Request for Approval of a Formula Proxy CT Methodology for Certain Reliant Energy Mid-Atlantic Power Holdings, LLC at 1, filed in Docket No. EL03-116 .

25 *Reliant Energy Mid-Atlantic Power Holdings, LLC v. PJM Interconnection, L.L.C.*, 104 FERC ¶61,040 at P 28 (2003) ("July 9th Order").

26 *Id*. at P 34 & n.14.

27 *Id*. at P 34.

28 *Id*. at P 37.

together, they satisfy the Federal Power Act's requirement that rates be just and reasonable. The Commission noted its particular interest in, taken as a whole, the market design resulted in "adequate incentives to attract and retain needed investment as well as rates that were not excessive," and that PJM should include such an analysis in each of its future State of the Market reports.[29] As explained *infra* Section F, the Commission has since approved PJM initiatives addressing each of these concerns.

**2. PJM Files Revisions to Local Market Power Rules**

After an extensive PJM stakeholder process that commenced in the LMPWG, the result was a stalemate. PJM filed pursuant to Section 206 of the Federal Power Act and in compliance with the July 9th Order a proposal to revise its local market power mitigation procedures and policies. In that filing, PJM emphasized that "[t]he existing offer cap mechanism provides adequate compensation to [capped] units."[30] The only exception was if resources became scarce in portions of its system.[31] PJM explained that no such scarcity conditions existed, but conceded that they could develop in the future and relief from offer capping might, in such circumstances, be appropriate. PJM proposed to continue to address local market power in the PJM region by capping offer prices of

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29 *Id*. at P 38.

30 PJM transmittal letter initiating Docket No. EL03-236 at 9 (September 30, 2003).

31 *Id*. at 10.

generation resources that are dispatched out of economic merit order to maintain reliability, but proposed four modifications:

(1) A Local Market Auction to procure the lowest cost option among transmission, generation and demand response upon a determination by the MMU that long-term scarcity conditions existed in a constrained market area.

(2) Application of a TPS test that would if passed, in conjunction with a determination by the MMU that sufficient competition exists, suspend the offer capping of units run out of merit order.

(3) Removal of exemptions from mitigation for units constructed after July 9, 1996.

(4) Addition of requirements that owners of generation located in the PJM region become members of PJM or otherwise agree to abide by all rules and procedures pertaining to generation and transmission in the PJM region in order to ensure uniformity of treatment of generators and to allow PJM to better manage reliability during emergencies.

PJM's proposal was to strengthen PJM's local market power rules while limiting the application of mitigation to periods when the market structure failed an explicit market structure test and provided a specific mechanism for allowing scarcity pricing.

### 3. Order on Competition Screen and FMUs

By order issued May 6, 2004, the Commission established a Reliability Compensation Issues policy and applied it to PJM's filing.[32] The Commission found that PJM's existing offer cap mitigation rules for units that are required to run are just and

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[32] *PJM Interconnection, L.L.C.*, 107 FERC ¶61,112 ("May 6th Order").

reasonable for most units.[33] The Commission accepted PJM's three pivotal supplier test, subject to PJM's providing additional justification of the standard and clear procedures as to when PJM would apply the standard.

However, the Commission found the application of those rules unjust and unreasonable when applied to a unit (i) for "80 percent or more of their run hours" and (ii) such units are "not recovering their costs."[34] The Commission required PJM to provide a process by which such units could recover at least their going forward costs, to adopt a policy concerning the retirement of generating units and to consider "the use of pricing or mitigation revisions that would recognize operating reserve deficiencies in its market design" and to file a report on its investigation of this issue.[35]

The Commission rejected, but later accepted on rehearing, PJM's proposal to remove the existing exemption from mitigation for post-1996 generating units.

The Commission rejected PJM's proposal for a Local Market Auction to address long-term scarcity, should it arise, because it lacked sufficient detail. It also rejected PJM's proposal that owners and lessees of generating units become members of PJM or otherwise agree to abide by PJM rules for generation and transmission, inviting PJM to

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33 *Id*. at P 36.

34 *Id*. at P 39.

35 *Id*. at PP 40, 42 & 83.

refile the proposal if it could "address its applicability and effect … on existing interconnection agreements, behind-the-meter generating units, and governmental entity generators." [36]

#### 4. Provisions for FMUs and Investigation of TPS Test

Included among the proposals submitted by PJM in compliance with the May 6th Order, was (i) the TPS test and (ii) a proposal to modify the mitigation rules to allow frequently mitigated units ("FMUs"), defined as units which are offer capped 80 percent or more of their run hours, to add the $40 or their unit-specific going forward costs to their SRMC, and to allow such offers to set the prevailing Locational Marginal Price (LMP). On rehearing, issued January 25, 2005, the Commission accepted the TPS test but instituted an investigation to determine whether the test is "too restrictive" and would "impose mitigation even in markets that are workably competitive." [37] The Commission also reaffirmed its prior holdings and accepted PJM's proposals concerning alternative compensation for FMUs and the retirement of units and found adequate PJM's investigation of scarcity pricing.[38]

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36 *Id*. at P 79.

37 *PJM Interconnection, L.L.C.*, 110 FERC ¶61,053 at P 84 (2005).

38 *Id*. at PP 2–3.

### 5. Settlement Resolves Competition Screen

On March 4, 2005, PJM submitted a Declaration prepared by the Market Monitor explaining the TPS test.[39]

By order issued July 5, 2005, among other things, the Commission set for hearing its investigation of the TPS test.[40] The Commission expanded the scope of the hearing in the Docket No. EL03-236-006 to include the relationship between PJM's mitigation measures, "including the appropriate test for determining whether to apply offer caps, and the ability of prices in load pockets to increase appropriately during periods of scarcity."[41] The Commission directed (at PP 120–122) that issues related to whether "prices in PJM, particularly prices received by mitigated generators, appropriately reflected scarcity prices" be set for hearing.

The parties reached a settlement at the end of 2005 endorsing the TPS test "resolving all issues set for hearing in Docket Nos. EL03-236-006 and EL04-121-000."[42] Those issues included the implementation of the TPS test, the establishment of new scarcity pricing rules set forth in a new section 6A of Schedule 1 of the OA, and an

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[39] Compliance filing of PJM Interconnection, L.L.C. in Docket No. EL03-236-006.

[40] *PJM Interconnection, L.L.C.*, 112 FERC ¶61,031 at P 119 (2005).

[41] *Id*. at Ordering Para. (C). *See supra* footnote no. 4 for list of issues. The Commission also consolidated to this proceeding the issues regarding PJM's proposal to exempt the APS South Interface from PJM's offer capping rules and to conduct annual competitive analyses to determine whether additional exemptions from offer capping are warranted (Docket No. EL04-121).

[42] Settlement Agreement at 1, filed in Docket No. EL03-236-000, et al. (November 16, 2005).

exemption from offer capping of the APS South Interface, subject to periodic review by the Market Monitoring Unit. The Commission accepted the settlement on January 27, 2006, without ruling on the merits, and made it effective the same day.[43]

### 6. Application of TPS Test to the Capacity Market

Contemporaneously with the proceedings on mitigation in Docket No. EL03-236, PJM initiated a major reform of its capacity market. In developing its proposal, PJM recognized that it needed to include provisions to protect the capacity market against the potential exercise of market power. PJM included the TPS test with exactly the same logic and mechanics as the TPS test used in the energy markets. The Commission approved the contested settlement for RPM on December 22, 2006, "find[ing] that the Settlement's provisions for market power monitoring and mitigation are reasonable."[44] The Commission required some changes, however, in order to provide for the administration of objective criteria specified in the tariff rather than rely upon discretionary judgments.[45]

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43 *PJM Interconnection, L.L.C., et al.*, 114 FERC ¶61,076.

44 *PJM Interconnection, L.L.C.*, 117 FERC ¶61,331 at P 100–01 (2006); *order on reh'g and clarification*, 119 FERC ¶61,318; *order on reh'g*, 121 FERC ¶ 61,173 (2007).

45 *Id*. at Ordering Para. (D). PJM subsequently filed the required changes regarding discretion, which the Commission approved. *PJM Interconnection, L.L.C.*, 122 FERC ¶61,264 (2008), *order accepting compliance filing, PJM Interconnection, L.L.C.*, 124 FERC ¶61,065 (2008).

The TPS test has been successfully applied in each RPM auction. The results of those auctions have been competitive. There have been no claims of over mitigation in the RPM market.

## II. LOCAL MARKET POWER RULES IN PJM

### A. Default Mitigation of Must-Run Units

When PJM implemented market-based locational marginal pricing ("LMP") for the PJM Interchange Energy Market on April 1, 1999, it included at Section 6 of Schedule 1 of the revised Operating Agreement provisions capping sell offers for generators at any time the generator is dispatched out–of-merit order because of a system constraint.[46] PJM had included substantially similar rules in its filing to transform itself from a power pool into an Independent System Operator.[47]

PJM filed and the Commission accepted the rules on local market power on the basis of an economic analysis performed by Paul Joskow and Rodney Frame. Their study explained the issue of local market power as follows:

> The nature of the potential local must run problem is that those who own or otherwise control specific generators, or small groups of generators, that must be run for reliability purposes under certain demand and supply conditions could, if unconstrained by contract or regulation, extract monopoly profits in world where the supply of generation services of all kinds is unregulated. The owners of such must-run generation could bid very high prices for

46 See Atlantic City Electric Co., et al., 86 FERC ¶61,248 (1999).

47 *See Pennsylvania-New Jersey-Maryland* Interconnection, et al., 81 FERC ¶61,257, at pp. 62,270–71 (1997).

> their output, and the ISO would be forced to call on them to operate for reliability reasons even if the energy which they provide could be replaced by much cheaper source absent the must run constraints.[48]

The rules governing the exercise of local market power recognize that when transmission constraints are binding, units in those local markets could extract monopoly profits, in the absence of explicit rules to address market power.

### B. Offer Caps at Competitive Levels

The local market power rules do not apply any offer cap to a unit dispatched in overall merit order (although the $1,000 per MWh system offer cap applies).[49] In PJM, there is no mitigation in the aggregate energy market when there are no binding transmission constraints and no mitigation in the unconstrained portions of the energy market when there are binding transmission constraints. The local market power rules establish a clear and non-discretionary process for offer capping that limits such offer capping to times when transmission constraints exist and such constraints create local markets that are not structurally competitive and create the conditions for the successful exercise of market power.

Offer capped units receive the higher of the market price or their offer cap. Thus, an efficient unit with a low marginal cost and a low offer cap will receive the higher

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[48] Supporting Companies' Report on Horizontal Market Power Analysis," Paul Joskow and Roger Frame (July 14, 1997).

[49] OA Schedule 1 § 1.10.1A(d)(viii) .

market price. In the unconstrained portions of the energy market, PJM has not imposed any cap on offers other than the system offer cap of $1,000 per MWh,[50] and prices have only rarely reached this level.

Although the Market Monitor consistently has determined that "the PJM aggregate Energy Market remains reasonably competitive,"[51] this is clearly not a conclusion that the PJM aggregate Energy Market is perfectly competitive. Some residual market power remains. The State of the Market Report provides a measure of markup in PJM, the difference between market clearing prices established by units on the margin and the marginal cost of those units. Mark up is a reasonable measure of market power in PJM. The Market Monitor has found that markup contributed 9.5 percent to average prices in 2007.[52]

### C. <u>The Offer Capping Rules</u>

Section 6.4.2 of Schedule 1 of the OA allows a Market Seller to determine the offer cap that will be applicable to its units by any of three alternative means: (1) the incremental operating cost of the generation resource plus 10 percent of such costs, (2) the weighted average locational marginal price at the generation bus, or (2) an amount

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50 *Id*.

51 *See*, *e.g.*, PJM 2007 State of the Market Report at 10.

52 PJM 2007 State of the Market Report at 64. Note that "costs" for purposes of this analysis included both the ten-percent adder to SRMC (*see infra* Section II.F) and the FMU adder.

determined by agreement between PJM and the Market Seller, subject to appeal to the Commission.[53] With only one exception, Market Sellers have used the marginal cost option. Offer capping in PJM has relied solely upon marginal costs (including marginal costs agreed to under the third option) and has never used the tariff provision that permits the use of average prices during competitive conditions. That tariff provision, to the extent that it could be accurately implemented, would simply produce the same results as the use of marginal costs. If units are offering competitively, they are offering at their own defined marginal cost and there is no reason for the additional tariff provision. The third method has been used once by one market participant, but the agreement was abrogated by the participant just prior to a filing seeking special relief from the local market power rules.

Some have raised concerns about the alternatives to calculating incremental operating costs because they involve the exercise of some discretion by the Market Monitor. The Market Monitor does not consider either alternative critical to retain and the Commission could safely remove them and thus remove concerns about discretion.[54]

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53 OA Schedule 1 § 6.4.2 (i),(ii)&(iv).

54 *See* Hon. Sudeen Kelly, et al., "The Subdelegation Doctrine and the Application of Reference Prices in Mitigating Market Power, ENERGY L. J., Vol. 26, No.2 at 324 (2005) ("[I]n PJM, … the market monitoring unit is allowed wide discretion to choose the number of hours that represent competitive conditions under the PJM estimate method for calculating reference prices.").

### D. Relationship to Order No. 697's Market Power Tests

The Commission has stated that the relationship between the TPS test and the market tests used by the Commission in other contexts and their relative effectiveness in ensuring proper pricing signals should be addressed.[55] The TPS test is derived directly from the Commission's market based rates tests and the TPS test relies upon the same fundamental economics as the Commission's market based rates tests. The TPS test is an automated and non-discretionary variant of the Commission's analysis that is applied in real time as actual market conditions vary.

The TPS test is derived from the principles of the Commission's order in *AEP Power Marketing, Inc.* ("AEP Order"),[56] which the Commission has since substantively codified into its rules and regulations in Order No. 697.[57] The differences between the TPS test and the Commission's test for authorization of market-based rates are required for the practical adaptation of the Commission's tests for use in real time. In addition to its consistency with approved analytical approaches, the TPS Test is also in accord with the Commission's policy preference for transparency and minimal reliance on

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55 112 FERC ¶61,031 at P 119; *See also California Independent System Operator Corporation*, 116 FERC ¶61,274 at P 1,032 (2006). *See supra* footnote no. 4.

56 107 FERC ¶61,018 (2004), *order on reh'g*, 108 FERC ¶61,026 (2004); *see also Wisvest Corp.*, 101 FERC ¶61,066 at P24 (2002).

57 18 CFR § 35.37, codified by *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Pubic Utilities*, Order No. 697, FERC Stats. & Regs. ¶31,252 (2007) ("Order No. 697"), *clarified*, 121 FERC ¶61,260 (2007), *order on reh'g*, Order No. 697-A, FERC Stats. & Regs. ¶31,268 (2008), *clarified*, 124 FERC ¶61,055 (2008).

administrative discretion.[58] The TPS test is a logical extension of the Commission's market power tests to a real-time application. Although no perfect test is available, the TPS test for local market power strikes a reasonable and practical balance between the requirement to check structural market power and the desire to minimize intervention in markets when competitive forces can be relied upon.

### 1. Market Power Analysis for Market-Based Rate Authorization

In Order No. 697, the Commission adopted two indicative market power screens and the more dispositive Delivered Price Test (DPT) for market power in the context of its evaluation of applications for authorization to charge market-based rates. With reference to the Delivered Price Test, the Commission stated:

> Using the economic capacity for each supplier, sellers should provide pivotal supplier, market share and market concentration analyses. Examining these three factors with the more robust output from the DPT will allow sellers to present a more complete view of the competitive conditions and their positions in the relevant market.[59]

The Commission's Delivered Price Test for market power appropriately defines the relevant market, and using that defined market, determines whether a supplier is

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58 *See*, *e.g.*, 117 FERC 61,331 at P 115 ("The Commission's regulations governing Market Monitors require that the regional transmission organization provide for objective monitoring of the markets it operates or administers… We are concerned that the Market Monitor may have excessive discretion as proposed in the Settlement.")

59 Order No. 697 at P 107. The Commission found that "a single market with Commission-approved market monitoring and mitigation and transparent prices provides added protection against a seller's ability to exercise market power but cannot replace the generation market power analysis." *Id*. at P 290.

pivotal, whether a supplier has a high market share and whether a supplier operates in a concentrated market.

The Commission defines the relevant market under the Delivered Price Test "by identifying potential suppliers based on market prices, input costs, and transmission availability, and calculates each supplier's economic capacity for each season/load condition." The Commission defines the relevant market to include suppliers with "costs less than or equal to 1.05 times the market price," i.e. those "suppliers that could sell into the destination market at a price less than or equal to 5 percent over the market price."[60] Thus, the relevant market includes all supply that is potentially competitive with the supplier and excludes supply that is not potentially competitive with the supplier.

The Commission's market based rates analysis then applies the components of the Delivered Price Test to the relevant market. A supplier fails if the supplier is pivotal (one pivotal supplier test), if it has a market share greater than or equal to 20 percent, or if the Herfindahl-Hirschman Index ("HHI") in the relevant market is greater than or equal to

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60 AEP Order at App. F; *see also Inquiry Concerning the Commission's Merger Policy Under the Federal Power Act: Policy Statement*, Order No. 592, FERC Stats. & Regs. ¶31,044, *mimeo* at 6 (1996), reconsideration denied, Order No. 592-A, 79 FERC ¶61,321 (1997) ("Merger Policy Statement"); Revised Filing Requirements Under Part 33 of the Commission's Regulations, Order No. 642, FERC Stats. & Regs. ¶31,111 (2000), *order on reh'g*, Order No. 642-A, 94 FERC ¶61,289 (2001); Order No. 697 at P 108.

2500.[61] A supplier is pivotal under the market power test if demand in the relevant market cannot be met without its supply (one pivotal supplier test).

The Commission recognizes the interactions among the multiple analyses under the Delivered Price Test and "encourages the most complete analysis of competitive conditions in the market as the data allow."[62]

For example, passing a single-pivotal supplier test does not end the inquiry because market participants can coordinate their behavior with other suppliers and can do so without overt interaction. The Commission has stated:

> Concentration statistics can indicate the likelihood of coordinated interaction in a market. All else being equal, the higher the HHI, the more firms can extract excess profits from the market. Likewise a low HHI can indicate a lower likelihood of coordinated interactions among suppliers and could be used to support a claim of a lack of market power by a seller that is pivotal or does have a 20 percent or greater market share in some or all season/load conditions. For example, a seller with a market share of 20 percent or greater could argue that … it would be unlikely to possess market power in an unconcentrated market (HHI less than 1000)."[63]

**2. The Delivered Pricing Test Derived for Use in Real Time**

The TPS test is an explicit derivation of the Delivered Price Test that is applied in real time. In the case of offer capping for local market power, PJM needs to apply a

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[61] Order No. 697 at P 111.

[62] *See* Order No. 697 at PP 111–117; AEP Order at PP 111–12.

[63] Order No. 697 at P 111.

market structure test in real time that measures actual market conditions as defined by actual system conditions as they change dynamically in response to changing load, generation and transmission system conditions.

The TPS test incorporates a balance of considerations in a real-time, dynamic setting, consistent with the Commission's market power tests, but avoids the application of judgment, the balancing of results of multiple analyses, and the possible need for additional inquiry. In real time, the test must be automated.

It is a strength of the TPS test, rather than a compromise, that it operates in real time and is based on real time system conditions. The Commission's tests must rely, for example, on analyses of historical data that focus on defined sets of hours in an effort to reflect the range of system conditions. The TPS test, by definition, reflects the actual system conditions as the operators of the system see them. The TPS test is based on actual, dynamic markets as they change in real time and does not depend on assumptions about system conditions. As a result, the need for the application of judgment is removed.

The use of only one component of the Delivered Priced Test, a one pivotal supplier test, does not address all of the considerations that lead the Commission to find the need for multiple, complementary analyses. The TPS test captures the balance inherent in the Delivered Price Test in a single test that can be used formulaically and automatically in real time. The Commission grants authorization to charge market-based rates under Order No. 697 on the basis of tests applicable for all market conditions and market-based rates remain effective for three years. The Commission has recognized that in the PJM real-time context, where all loads pay a single clearing price based on the highest accepted generation offers, the market power test needs to be applied in real time to reflect changing market conditions.[64] The TPS test can identify market power and trigger mitigation for a period and then, on the same day, identify the absence of market power and avoid mitigation for another period for the same constraint. The determination must be based on actual market conditions, based on transmission constraints which define more limited geographic markets, and the actual potential to exercise market power in real time, or in specific hours of the Day-ahead Energy Market. A finding that a market is not structurally competitive for one period of time does not mean that it will not be found to be competitive when market conditions change. The PJM TPS test does not result in offer capping when local markets are competitive.

The TPS test is also consistent with the Commission's Delivered Price Test in that it tests for the interaction among attributes of individual participants and features of the market structure. The TPS test is an explicit test for the potential ability to profitably engage in unilateral action as well as coordinated action that accounts simultaneously

64 May 16th Order at P 48 ("We agree with Maryland PSC and the MMU that market conditions, and thus, the ability to exercise market power, can change from hour-to-hour as demand, supply, and transmission availability change…").

for market shares and the balance of supply and demand in the market. The TPS test focuses on competitive conditions at the margin, where the market price is determined.

### 3. The TPS Test Broadens the Definition of the Relevant Market

The Delivered Price Test defines the relevant market to include all suppliers with marginal costs less than or equal to 1.05 times the market price, but PJM's TPS test includes suppliers with marginal costs less than or equal to 1.50 times the market price. The TPS test includes substantially more competitors.

### 4. Relaxation of Local Market Power Rules

The TPS test represents a significant relaxation of the PJM local market power rule, in place from April 1, 1999 through March 2006, which required offer capping whenever a local market was created by a transmission constraint, without consideration of market structure.

### 5. Inelastic Demand

The TPS test explicitly incorporates the relationship between supply and demand in the definition of pivotal. The TPS test provides a clear test for whether excess supply is adequate to offset other structural features of the market and result in an adequately competitive market structure. The greater the competitive supply relative to demand, the less likely that three suppliers will be jointly pivotal, all else being equal.

The design of TPS test, like the Delivered Price Test, reflects the context of the elasticity conditions present in wholesale electric power markets. As the Commission stated: "it must be recognized that demand elasticity is extremely small in electricity markets; in other words, because electricity is considered an essential service, the demand for it is not very responsive to price increases."[65] The fact that electricity markets exhibit very low price elasticity of demand is an important variable in determining whether a particular market structure is likely to result in a competitive outcome. It is essential that market power tests (and evaluations of market power tests) neither ignore elasticity nor make counterfactual elasticity assumptions. As the Commission states, "[i]n markets with very little demand elasticity, a pivotal supplier could extract significant monopoly rents during peak periods because customers have few, if any, alternatives."[66] The Commission also stated, in reference to dominant firm models of behavior:

> In both of these models, the lower the demand elasticity, the higher the mark-up over marginal costs, it must be recognized that demand elasticity is extremely small in electricity markets; in other words, because electricity is considered an essential service, the demand for it is not very responsive to price increases. These models illustrate the need for a conservative approach in order to ensure competitive outcomes for customers because many

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65 AEP Order at P 103; *see also* Order No. 697 at P 89.

66 *Id.* at P72.

> customers lack of the key protections against market power: demand response."[67]

As recognized by the Commission, the market structure tests identified in the market based rates orders must be interpreted jointly. In the context of a market with an extremely inelastic demand curve, the existence of two jointly pivotal suppliers, regardless of the amount of excess capacity available, does not provide a market structure that will result in a competitive outcome. The 20 percent market share and the HHI screen are also weak screens for structural market power on a stand-alone basis. A market share in excess of 20 percent does not demonstrate market power if the holder of that market share is not jointly pivotal and is unlikely to be able to affect the market price. A market share less than 20 percent does not demonstrate the absence of market power if the holder of that market share is jointly pivotal and is likely to be able to affect the market price. An HHI in excess of 2500 does not demonstrate market power if the relevant owners are not jointly pivotal and are unlikely to be able to affect the market price. An HHI less than 2500 does not demonstrate the absence of market power if the relevant owners are jointly pivotal and are likely to be able to affect the market price.[68]

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[67] *Id*. at P 10.

[68] For detailed examples, see Joseph E. Bowring, PJM market monitor. "MMU Analysis of Combined Regulation Market," PJM Market Implementation Committee Meeting (December 20, 2006).

### 6. TPS Results Consistent with FERC Market Power Tests

Analysis of the various measures of market structure show that the combination of factors that typically cause a failure of pivotal supplier tests also result in failing the market share and/or HHI tests. The characteristics of markets that pass the TPS test correlate better with competitive levels of HHI and market share.

The TPS test, as implemented, is consistent with the Commission's sophisticated, multilayered market power tests. The TPS test explicitly incorporates the impact of excess supply and implicitly accounts for the impact of the price elasticity of demand in the market power tests. In addition, the three pivotal threshold requires a minimum of four competitors to pass the test, similar to the 2500 HHI and 20 percent market share screens used by FERC in conjunction with its single pivotal supplier screen.

Although it is consistent with the Commission's market power screens, the TPS test is different. The TPS test can show the existence of structural market power when the HHI is less than 2500 and the maximum market share is less than 20 percent. The TPS test can also show the absence of market power when the HHI is greater than 2500 and the maximum market share is greater than 20 percent. The TPS test is more accurate than the HHI and market share tests because it focuses on the relationship between demand and the most significant aspect of the ownership structure of supply available to meet it.

A one pivotal supplier test by itself (meaning two jointly pivotal suppliers are considered competitive) is not an adequate market structure test because it rules out only the extreme case of structural market power (monopoly) in power markets with inelastic demand. When there is one pivotal supplier, it has the ability to unilaterally increase the price. Even when there are multiple suppliers in a load pocket, a single pivotal supplier has monopoly power at the margin. A single pivotal supplier is a monopolist facing a perfectly inelastic residual demand curve. This is an extreme case of local market power.

A two pivotal supplier test (three jointly pivotal suppliers are considered competitive) is not an adequate market structure test because markets that pass this test exhibit market structure conditions that fail the Commission market power tests including HHI and market share, show significant markups under Cournot competition and facilitate various forms of unilateral or parallel behavior that can result in prices significantly greater than the competitive level.

In a market that passes the two pivotal supplier test but fails the TPS test, substantial structural market power exists. For example, there is a load pocket with three suppliers, each with 1,000 MW of capacity, and load is 1,000 MW. In this case, the market would pass the two pivotal supplier test but fail the TPS test. However, the market structure would fail market structure tests under the Commission's market based rates approach. The lowest possible HHI in this market is 3333, assuming that all suppliers have equal marginal costs and each serves equal amounts of load. HHI's of 3333 fail the Commission's market power test and are generally considered inconsistent with a competitive market, even with relatively elastic demand. In this case, three suppliers are jointly pivotal. This market would appropriately fail the TPS test.

A TPS test is the minimum acceptable test because it is associated with HHI levels within the competitive range, it will result in lower mark-ups under Cournot competition models, and it will make parallel behavior more difficult. This test does not perfectly match the Commission's test. A market could, under certain circumstances, pass the TPS test but fail the Commission's market power tests. For example, a market with four equally sized suppliers could pass the TPS test, but fail the Commission's market power tests.

The TPS test explicitly accounts for the relationship between supply and demand while the HHI and market share tests alone do not.

### E. The TPS Test

PJM developed and successfully implemented a test for local market power (the TPS test) that removes offer caps in conditions where a unit dispatched out of merit order due to a constraint faces sufficient competition to substantially limit the exercise of market power.

### 1. Allows Maximum Reliance on Market Structure to Produce Competitive Outcomes

PJM markets are designed to promote competitive outcomes. Market design is the primary means of achieving and promoting competitive outcomes in the PJM markets. One of the Market Monitor's primary goals is to identify actual or potential market design flaws.[69] PJM's and the Market Monitor's market power mitigation goals have focused on market designs that promote competition (i.e., a structural basis for competitive outcomes) and on limiting market power mitigation to instances where market structure is not competitive and thus where market design alone cannot mitigate market power. In the PJM Energy Market, this occurs only in the case of local market power. When a transmission constraint creates the potential for local market power, PJM applies a structural test to determine if the local market is competitive, applies a behavioral test to determine if generator offers exceed competitive levels and applies a market performance test to determine if such generator offers would affect the market price. Where this multipart test is failed, the participant's offers can be capped to the participant's cost offer.

### 2. The TPS Test: Basic Concept

The structural test for implementing offer capping set forth in the PJM Amended and Restated Operating Agreement (OA) Schedule 1, Sections 6.4.1(e) and (f) is the TPS

[69] PJM. "Open Access Transmission Tariff (OATT)," "Attachment M: Market Monitoring Plan," Third Revised Sheet No. 452 (Effective July 17, 2006).

test. The TPS test is applied by PJM on an ongoing basis in order to determine whether offer capping is required for any binding transmission constraint. The TPS test defined in the OA represents a significant evolution in accuracy because the test is applied in real time using the actual data used by the dispatchers to dispatch the system including transmission constraints and the real-time details of incremental generator availability.

As a result of PJM's implementation of the TPS test in real time, the actual competitive conditions associated with each binding constraint are analyzed in real time as they arise. The TPS test replaced the prior approach which was to offer cap all units required to resolve a binding constraint. The application of the TPS test has meant a reduction in the application of offer capping. As a result of the application of the TPS test in the energy markets, offer capping is applied only at times when the local market structure is not competitive and only to those participants with structural market power.

For example, if there are five suppliers in an area, each with 100 MW of generation capability and the load in the area is 500 MW, all five suppliers are individually and jointly pivotal. If load is 400 MW, no single supplier is pivotal, but two suppliers are jointly pivotal. If the load is 300 MW, no single supplier is pivotal, but three suppliers are jointly pivotal. The measure of pivotal is: (Total Supply – Participants' Supply)/Total Load. When the measure is less than 1.0, the relevant participants are pivotal. A pivotal supplier(s) has market power because load cannot be met without its supply and load is extremely price inelastic in real time.

It is not enough to consider a supplier acting alone, as sophisticated market participants have detailed information about system conditions, can monitor their competitors' behavior and can adjust without the overt collusion contemplated by the antitrust laws.

### 3. The TPS Test: Mechanics of Application

The TPS test measures the degree to which the supply from three generation suppliers, as defined by PJM's market solution software, is required in order to meet the demand to relieve a constraint. Two key variables in the analysis are supply and demand. The supply consists of the incremental, effective megawatts of supply available to relieve the constraint, with a distribution factor (DFAX) greater than, or equal to, the DFAX used by PJM in operations.[70] The demand consists of the incremental, effective megawatts of supply required by PJM dispatchers to relieve the constraint. Both supply

[70] A unit's contribution toward effective, incrementally available supply is based on the DFAX of the unit relative to the constraint and the unit's incrementally available capacity over current load levels. Effective, incrementally available MW from an unloaded 100 MW 15-minute start combustion turbine (CT) with a DFAX of 0.05 to a constraint would be 5 MW relative to the constraint in question. Effective, incrementally available MW from a 200 MW steam unit, with 100 MW loaded, a 50 MW ramp rate and a DFAX of 0.5 to the constraint would be 25 MW. The TPS test automatically uses the same incremental supply, including any distribution factor ("DFAX") cutoff, used by PJM in actually operating the market.

and demand are defined for the test exactly as PJM dispatchers define them. The TPS test is rooted in accurate, real-time market facts.

The supply included in the TPS test consists of the incremental, effective MW of supply that are available at a price less than, or equal to, 1.5 times the clearing price ($P_c$) that would result from the intersection of the incremental demand and the incremental supply available to resolve the constraint. The effective cost and MW pairs from a particular participant are based on the lesser of the participant's cost or price schedule, if the unit is offline, or the current operational (price or cost) schedule if the unit is already being dispatched by PJM. This measure of supply is termed the relevant effective supply ($S$) in the market for the relief of the constraint in question. In every case, incrementally available supply is measured as incremental effective MW of supply, as shown in Equation II-1, and the clearing price ($P_c$) is defined as shown in Equation II-2:

**Equation II-1 Incremental effective MW of supply**

$$MW \bullet DFAX$$

**Equation II-2 Price of clearing offer**

$$P_c = \frac{Offer_c - SMP}{DFAX_c}.$$

To be part of the relevant supply, the effective offer of incremental supplier $i$ must be less than, or equal to, 1.5 times $P_c$:

**Equation II-3 Relevant and effective offer**

$$P_{ie} = \frac{Offer_i - SMP}{DFAX_i} \leq 1.5 \cdot P_c .$$

Where the relevant, effective incremental supply of supplier *i* is a function of price:

**Equation II-4 Relevant and effective supply of supplier *i***

$$S_i = MW\left(P_{ie}\right) \bullet DFAX_i .$$

Where $S_i$ is the relevant effective supply (relevant, incremental, effective supply) of supplier *i*, total relevant effective supply (total relevant, incremental and effective supply) for suppliers *i*=1 to n is shown in Equation II-5:

**Equation II-5 Total relevant, effective supply**

$$S = \sum_{i=1}^{n} S_i .$$

Each effective supplier, from 1 to n, is ranked, from the largest to the smallest relevant effective supply, relative to the constraint for which it is being tested. In the first iteration of the test, the two largest suppliers are combined with the third largest supplier, and this combined supply is subtracted from total relevant effective supply. The resulting net amount of relevant effective supply is divided by the total relief required (*D*). Where *j* defines the supplier being tested in combination with the two largest suppliers (initially the third largest supplier with *j*=3), Equation II-6 shows the formula for the three pivotal supplier metric, i.e., the three pivotal residual supplier index (RSI3):

**Equation II-6  Calculating the TPS test**

$$RSI3_j = \frac{\sum_{i=1}^{n} S_i - \sum_{i=1}^{2} S_i - S_j}{D}.$$

Where $j$=3, if $RSI3_j$ is less than, or equal to, 1.0, then the three largest suppliers in the market for the relief of the constraint fail the TPS test. That is, the three largest suppliers are jointly pivotal for the local market created by the need to relieve the constraint using local, out of merit units. If $RSI3_j$ is greater than 1.0, then the three largest potential suppliers of relief MW pass the test and the remaining suppliers ($j$=4..n) pass the test. In the event of a failure of the three largest suppliers, further iterations of the test are needed, with each subsequent iteration testing a subsequently smaller supplier ($j$=4..n) in combination with the two largest suppliers. In each iteration, if $RSI3_j$ is less than 1.0, it indicates that the tested supplier, in combination with the two largest suppliers, has failed the test. Iterations of the test continue until the combination of the two largest suppliers and a supplier $j$ result in $RSI3_j$ greater than 1.0. When the result of this process is that $RSI3_j$ is greater than 1.0, the remaining suppliers pass the test.

If a supplier fails the test for a constraint, units that are part of a supplier's relevant effective supply with respect to a constraint can have their offers capped at cost plus 10 percent, or cost plus relevant adders for frequently mitigated units and associated units. Offer capping only occurs to the extent that the units of this supplier's relevant, effective supply are offered at greater than cost plus 10 percent, are actually dispatched to contribute to the relief of the constraint in question and would therefore have affected the market clearing price but for offer capping.

#### 4. Definition of the Relevant Market

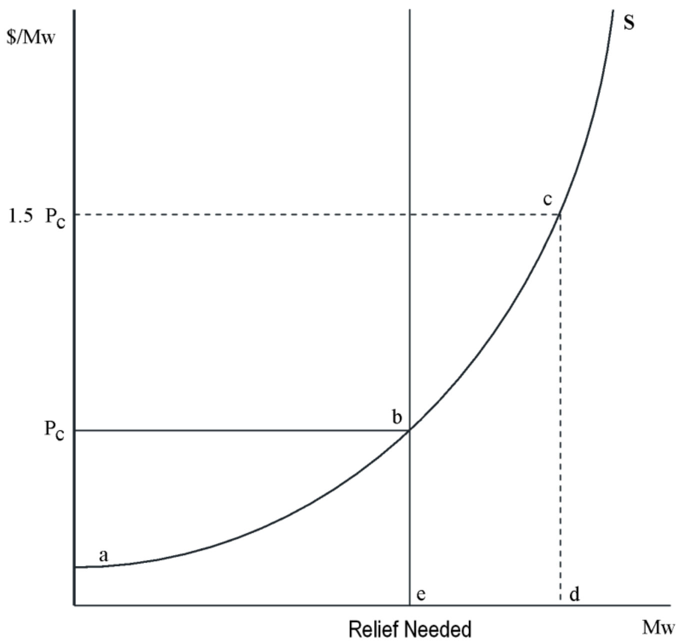
The goal of defining the relevant market is to determine those producers that are actual competitors, potential providers of substitute output, to the units that clear in a market. The existence of market power within that defined market depends on the ability of the firm to raise price while continuing to sell its output. A firm cannot successfully increase the market price above the competitive level if competitors would replace its output when it did so.

The TPS test is designed to analyze the relevant market. For example, in the case of the market for out of merit generation needed to relieve a constraint in real time, the TPS test examines the supply specifically available to provide that relief. The TPS test measures the degree to which the supply from three firms, as defined by PJM's market solution software, is required in order to meet the demand to relieve a constraint. The market demand consists of the incremental, effective MW required to relieve the constraint. The market supply consists of the incremental, effective MW of supply available to relieve the constraint. For purposes of the test, incremental effective megawatts of supply are attributed to specific suppliers on the basis of their control of the associated assets. Generation capacity controlled directly or indirectly through affiliates or through contracts with third parties is attributed to a single supplier.

The supply directly included as relevant to the market in the TPS test consists of the incremental, effective MW of supply that are available at a price less than, or equal to, 1.5 times the clearing price ($P_c$) that would result from the intersection of demand (constraint relief required) and the incremental supply available to resolve the constraint. This measure of supply is termed the relevant effective supply ($S$) in the market for the relief of the constraint in question. In every case, incrementally available supply is measured as incremental effective megawatts of supply, as shown in Equation II-1, and the clearing price ($P_c$) is defined as shown in Equation II-2 above.

Figure II-1 illustrates the interaction between the relief requirement and the effective supply available, as recognized by PJM's market solution software. The clearing price ($P_c$) is generated at the point of intersection of the relief required (D) and relevant effective supply (S). The effective cost and MW pairs from a particular participant are based on the lesser of the participant's cost or price schedule, if the unit is offline, or the current operational (price or cost) schedule if the unit is already being dispatched by PJM. Theoretically, the relief requirement can be fully met at the point of intersection (b) of (D) and (S) by the effective megawatts of supply available at $P_c$ (e). However, as indicated above, the market defined for the test also includes potentially effective megawatts of supply in excess of what is needed to clear the market (d), defined as the effective megawatts of supply available at a price less than, or equal to, 1.5 times the clearing price ($P_c$).

**Figure II-1**




As noted, the TPS test uses a more inclusive definition of potential competitors (potential suppliers of substitute output) in its definition of the relevant market than the Commission's Delivered Price Test. The Commission's Delivered Price Test defines the relevant market to include all offers with costs less than, or equal to, 1.05 times the market price, while the TPS test includes all offers with costs less than, or equal to, 1.50

times the clearing price for the local market. The Commission definition means that, if the marginal unit were to clear the market and set the clearing price based on an offer of $200 per MWh, all units with costs less than, or equal to, $210 per MWh would be considered reasonable competitive substitutes for the suppliers that did clear in the market, and would have a competitive effect on the offer of the marginal unit. These units are all defined to be meaningful competitors in the sense that it is assumed that their behavior constrains the behavior of the marginal and inframarginal units.

The TPS test definition means that, if the marginal unit sets the clearing price based on an offer of $200 per MWh, all units with costs less than or equal to $300 per MWh have a competitive effect on the offer of the marginal unit. While units available at a cost less than or equal to $200 are all that is needed to relieve the constraint, the current implementation of the TPS test would includes all units available for $300 or less as meaningful substitutes in the market to relieve the constraint in question. These units are all defined to be meaningful competitors in the sense that it is assumed that their behavior constrains the behavior of the marginal and inframarginal units. Clearly, the TPS test incorporates a definition of meaningful competitors that is at the extremely high end of inclusive. It is questionable whether a $300 effective offer meaningfully constrains the effective offer of a $200 unit.

There is an interaction between the TPS test and the 1.50 price multiplier in the market definition, relative to the interaction between a one pivotal supplier test and a 1.05 price multiplier in the market definition. For example, assume there are five suppliers, suppliers A through E, each with 250 MW of effective supply for the market in question. Assume further that supplier A has an effective cost of $100 per MW (the effective cost of one MW of supply delivered to the market from Supplier A is $100, accounting for DFAX), supplier B has an effective cost of $120, supplier C has an effective cost of $130, Supplier D has an effective cost of $140 and Supplier E has an effective cost of $150.

If the incremental relief required (demand) in the market were 200 MW, the market could be cleared with the output from any one supplier (250 MW > 200 MW). If dispatched in cost order, the market would clear with Supplier A providing 200 MW of output at an effective cost of $100. At a clearing price of $100, the single pivotal supplier test would define the market as encompassing all supply that could be delivered at $105 or less ($100 x 1.05 = $105). Only Supplier A would meet that criteria, and Supplier A would, by definition, fail the Commission's one pivotal supplier test, as it would be the only supplier in the defined market. Using the 1.05 market definition, Supplier A would also fail the market share and the HHI screens (100 percent market share and a corresponding HHI of 10000).[71] Supplier A could raise its effective price for all, or part of its output, to $119 without suffering any loss of demand. Any portion offered over $120 could be lost to Supplier B, but any lower priced portion of Supplier A's output would clear at $120.

Using a market definition of 1.50 would include the potential effective megawatts of supply from all five suppliers ($100 x 1.50 = $150). Using this definition of the market would allow each of the suppliers, including Supplier A, to pass the single pivotal supplier test. If 1.50 were used as the cutoff for the market share and HHI screens, suppliers A, B, C, D and E would each have a market share of 20 percent and the HHI would be 2000. This would constitute a failure of FERC's market share test but a passing score on the HHI screen by the suppliers in the market.

When the TPS test is applied to the defined market, all five suppliers A through E would pass. This illustrates the fact that the TPS Test can result in a finding of no structural market power when the Commission delivered price test would be failed and when a participant does have structural market power. The market definition, including a multiplier of 1.5, includes potential suppliers that do not providing meaningfully competitive substitutes for Supplier A's output.

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71 It is important to note that the correct measure of market share, and resulting HHI scores, would only examine the proportional output of participants that would actually clear (actually produce output) in the market, not the proportional share of uncleared capacity.

If the incremental relief required (demand) in the market were instead 450 MW, the market could be cleared with the output from any two suppliers (500 MW > 450 MW). If dispatched in cost order, the market would clear with Supplier B providing 200 MW of output at an effective cost of $120. At a clearing price of $120, the single pivotal supplier test would define the market as encompassing all supply that could be delivered at $126 or less ($120 x 1.05 = $126). Only Supplier A and B would meet that criterion. Supplier A and B would individually fail the one pivotal supplier test, as both Supplier A and B are necessary, within the defined market, to meet the demand. Both supplier A and supplier B have the unilateral ability to affect price via economic or physical withholding. If Supplier A were to raise its effective price to $129, it would potentially lose 50 MW of output to B, but it would increase the market clearing price from $120 to $129 on the remaining 200 MW of its output. Supplier B could raise its price to $129 for all of its output without sacrificing any of its 200 MW of sales. Any portion offered over $130 would be lost to Supplier C.

Within the context of the 1.05 market definition, Supplier A and Supplier B would also fail the market share and the HHI screens (Supplier A and B would each have 50% of supply available in the defined market, with a corresponding HHI of 5000).[72] Using a market definition of 1.50 would include the potential effective MW from all five

72 It is important to note that the correct measure of market share, and resulting HHI scores, would only examine the proportional output of participants that would actually clear (actually produce output) in the market, not the proportional share of uncleared capacity.

suppliers ($120 x 1.50 = $180). Using this definition of the market would mean that all of the suppliers, including Supplier A, pass the single pivotal supplier test. If 1.50 were used as the cutoff for the market share and HHI screens, supplier A, B, C, D and E would each have a market share of .20 and the HHI would be 2000. This would constitute a failure of FERC's market share screen by the suppliers in the market. A failure of the screen would be appropriate for Supplier A and B. But note that the market share and HHI results are not sensitive to the change in the relationship between supply and demand. Applying the TPS test to the defined market, each supplier, from a Supplier A to Supplier E would pass (1250 – 250 – 250 – 250)/450.

### F. Calculation of Short-Run Marginal Costs

The PJM tariff requires that all generation owners submit marginal cost-based offers every day. The market power mitigation rules provide for offer caps at short-run marginal costs ("SRMC"). In addition, generation owners may submit price-based offers. There are detailed rules governing the definition of the submitted costs. Despite the appearance of complexity, the definition of marginal cost is quite straightforward. Marginal costs are fuel cost times unit heat rate, plus variable operating and maintenance expense, plus emissions costs, plus relevant opportunity costs if any, plus ten percent. The cost development process and rules predated the introduction of PJM markets and the ten percent adder was defined by generation owners to recognize that there is some variability in the costs of combustion turbines within a day. The ten percent adder was not designed to be a margin. Generation owners receive assurance that any error in their calculation of SRMC is likely to overestimate rather than underestimate marginal costs by the inclusion of a ten-percent adder over and above all documented incremental operating costs.[73]

Each Market Seller (not electing an alternative approach) has the responsibility to develop and support a calculation of its own SRMC, following the guidelines agreed upon by PJM stakeholders through the Cost Development Task Force ("CDTF").[74] The PJM tariff, by requiring the generation owners to submit their own costs, subject to agreed upon definitions, gives some deference to the knowledge that generation owners have of their own units. The market monitoring unit does not create, establish or estimate the marginal cost offers on behalf of generation owners. The Market Monitoring Unit does verify marginal cost offers in a variety of ways and ensures that the offers accurately reflect marginal costs. The role of the Market Monitoring Unit then and now has been to advise the CDTF on the appropriate guidelines and to verify that Sell Offers comport with those guidelines and are appropriately documented. Market Sellers have frequently consulted with the Market Monitor on how to handle their costs and from time-to-time, the Market Monitor has required appropriate documentation of costs. The

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73 OA Schedule 1 § 6.4.2(a)(ii).

74 The guidelines are included in PJM Manual M-15 (Cost Development Guidelines), which is posted on PJM's Website at: *http://www.pjm.com/contributions/pjm-manuals/manuals.html*.

Market Monitor has never contested a cost that was appropriately documented and neither the Market Monitor nor any Market Seller has ever referred a dispute over such costs to the Commission.

Some have questioned whether Market Sellers should be relied upon to make this determination,[75] but the experience of the Market Monitor has been that the process works. Allowing Market Sellers to calculate their own marginal costs subject to oversight does afford them significant procedural protection against the possibility of over mitigation that could result from an administrative process that would permit the market monitor discretion in determining a seller's marginal costs.

An accurate calculation of SRMC is equally important for a seller facing competition. A rational, competitive seller will want to cover its short-run marginal costs without missing a sale. The CDTF adds structure to a process in which successful suppliers facing competition would voluntarily engage. The Market Monitor has observed that sellers in PJM use sell offers calculated through the CDTF method when submitting market offers under competitive conditions.

Marginal cost offers in PJM markets accurately reflect actual marginal costs. That is an essential component of the PJM market power mitigation rules.

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75 *See* Kelly, "The Subdelegation Doctrine" at 324 ("[I]n PJM, the supplier is allowed to choose between the methods for calculating reference price").

## III. ISSUES

### A. The Overall Market Design Must Ensure Adequate Compensation

The energy market can and did function efficiently even when offer capping for local market power applied whenever transmission constraints created local markets.[76] From the standpoint of economic theory, there was nothing wrong with PJM's approach to offer capping based on SRMC. PJM could have continued to cap offers in the PJM Energy Market indefinitely without worry about harm to generation owners or economic efficiency. This does not mean, however, that PJM's overall market design was sound. The energy market is only one piece of the puzzle. In order to ensure appropriate incentives to Markets Sellers, it is also important to properly price capacity and to appropriately price energy in conditions of scarcity. It is important to understand that in the context of a correct overall market design, the PJM markets could function well and apply offer capping in all but scarcity conditions without the need for a test to determine when adequately competitive conditions are present.

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[76] The Commission is correct to observe that: "If the Three-Pivotal-Supplier Test is a poor indicator of market power, using the test to determine whether to mitigate generators (including those that are currently exempt from mitigation) could result in imposing offer caps more often than is justified." May 16th Order at P 59. But it is worth emphasizing that if (i) SRMC is calculated within a 10-percent margin for error and (ii) supply is not scarce, then the application of more mitigation than necessary does not result in "over mitigation" in the sense that a supplier would be paid too little. Indeed given the level of the adder, it is considerably more likely that load would remain exposed to a residual level of market-power based pricing.

### B. Over Mitigation

Although the purpose of the local market power rules is the prevention of the exercise of local market power, some have asserted that these rules have unintended consequences for the operation of the energy markets, including the suppression of incentives for investment.

Over mitigation means either forcing a competitive outcome in the absence of market power or failing to provide appropriate incentives for investment by preventing generators from recovering their costs. Type I error is a false positive and Type II error is a false negative. In the context of a designing a screen to detect market power, Type I error means that the screen detects market power where none exists. Type II error means that the screen has failed to detect market power where it exists.

The concern about over mitigation is that the current test is designed to minimize the effects of market power rather than to provide a balance between the Type I and Type II related costs.

Type I error results in participants being forced to behave competitively, that is offer at or close to marginal cost. Thus, the cost of Type I error is zero or very close to zero, so long as scarcity signals are not suppressed. Scarcity signals are not suppressed under the current market design. With the current RPM design, scarcity revenues are provided in the capacity market and to some extent, via the scarcity pricing provisions in the energy market. Type II error imposes considerable costs. If market power is not detected and it is not mitigated, the result is price distortion in the market, inefficient market signals and wealth transfers. As the costs of Type II error are positive and large while the costs of Type I error are non-existent in a properly designed market, it would be reasonable, from a policy perspective to design market power screens to minimize Type II error.

The TPS test was designed and introduced in order to reduce Type I error compared to the prior rule that imposed offer caps whenever there was a binding transmission constraint that required out of merit generation. At the time of the introduction of the TPS test to PJM markets, PJM markets were also undergoing a market redesign to include scarcity pricing and RPM that eliminated any concerns about Type I error. It would be reasonable to argue that the TPS test, with a 1.5 threshold for market definition, is too insensitive to market power (errs on the side of Type II error) given PJM's market design.

The introduction of the TPS test has resulted in less offer capping in the energy market. Participants can and do pass the TPS test when the test fails to find the presence of structural market power. The introduction of the TPS test has reduced the incidence of Type I error at a time when the potential issues with Type I error have been largely resolved through changes to the PJM market design. The concern should therefore be whether the TPS test permits an unacceptable amount of Type II error.

### C. <u>Conduct and Impact Tests</u>

The analysis of any market requires an examination of market structure, market behavior or conduct and market performance. This is fundamental industrial organization economics. The TPS Test incorporates all three analytical elements. The Commission's market based rates screens and tests also incorporate all three elements of market analysis. The TPS Test starts with a definition of the relevant market. The Commission's market based rates approach also starts with a definition of the relevant market.

What is termed the "conduct-impact" approach generally ignores market structure and focuses on the second and third elements of market analysis, the behavior of generation owners and the resulting impact on market performance.

The assertion that the conduct-impact approach represents an alternative to the TPS approach is thus based on misconceptions about both approaches. The TPS approach begins with the definition of the relevant market and the market structure of that market. If the market structure test is failed because there are three or fewer pivotal suppliers, the TPS approach considers the behavior of market participants. If the behavior test is failed because one or more of the relevant market participants is offering in a non-competitive manner, the TPS approach considers the impact on the market. If the unit fails the behavior screen and the unit is marginal, it also fails the market performance screen.

The conduct-impact approach is applied more broadly than the TPS Test, in part because the TPS first applies a structural test. The conduct-impact approach permits mitigation for market power in the aggregate market even when the market is unconstrained and without an explicit definition of the relevant market. There is no comparable mitigation in PJM markets. The TPS Test is applied in PJM solely to local markets, solely for defining local market power and results in mitigation for such local markets only when the local market structure is not competitive, when a market participant's offer is greater than a competitive level and when there would be a market impact.

The conduct-impact approach, as applied, does not use dynamic definitions of markets and market supply and demand that are derived from the actual operations of the market systems. In a fully developed nodal pricing market, local markets are dynamic and the relevant supply and demand are correspondingly dynamic. Fixed definitions of the relevant constraints will miss key elements of markets.

The conduct-impact approach, as applied, also includes substantial discretion for market monitors. This discretion includes the setting of marginal costs or reference prices.

The conduct-impact approach, if applied in the PJM markets in the same manner as it is applied elsewhere, would permit substantial market power. While the actual conduct and impact thresholds are not based on any stated theory, the thresholds defined in actual tariffs are substantially in excess of marginal cost. In some limited cases involving predefined local markets where the market structure has identified issues, the actual offer caps are very similar to those that would apply under PJM rules in similar circumstances. The TPS test, because it relies first on a market structure test to determine if the market structure is competitive, can incorporate mitigation measures directly based on market outcomes.

### D. CAISO'S MRTU Adopts Mitigation Based on a TPS Test

The California Independent System Operator Corporation ("CAISO") has historically relied upon a conduct and impact type test, but determined in the course of adopting a market design employing LMP ("MRTU"), included local market power rules and an associated market power test similar to PJM's. The CAISO will apply the TPS test annually, and eventually seasonally, rather than dynamically in the Day Ahead and Real Time Energy Markets as in PJM. The California Public Utilities Commission and a Pacific Gas & Electric Company, among others, have supported that decision because they, like the Commission, are "mindful of the fact that the California energy crisis affected not only California, but also the entire Western Interconnection" and the MRTU, including enhanced measures for market power mitigation, "are intended to protect not only California, but also the entire West, from a repeat of that crisis."[77]

The Commission approved the CAISO's proposed approach to market power mitigation by order issued July 1, 2005,[78] and has since reaffirmed the CAISO's proposal, finding "that the Three Pivotal Supplier Test is reasonable." However, the Commission agreed with certain intervenors that "a Three Pivotal Supplier Test may be overly stringent" and directed the CAISO's Market Surveillance Committee to "examine whether an alternative competitive screen to identify market power opportunities for generation in load pockets should be considered" during the first year of implementation, and "to include its findings in the CAISO's quarterly, post-implementation performance reports."

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77 *California Independent System Operator Corporation*, 112 FERC ¶61,013 at P 122 at P 3 (2006); *See* Notice of Intervention, Limited Protest, and Comments of the California Public Utilities Commission on the California ISO's MRTU Tariff filed in Docket No. ER06-615-000 at 7 (April 10, 2006) ("The CPUC continues to strongly support the CAISO's reliance on a PJM-style LMPM proposal, as opposed to a conduct/impact approach, as was implemented in the NY ISO control area."); Reply Comments of Pacific Gas & Electric Company filed in Docket No. ER06-615-000 at 5 ("PG&E strongly supports the use of PJM–style local market power mitigation process ("LMPM") as part of MRTU, which will give California the assurance of stability that is needed for a successful market, and which is additionally justified by the revenue adequacy that the CPUC's RA program will provide.").

78 112 FERC ¶61,013.

The CAISO explains its decision to switch from the conduct-and-impact in order to better protect consumers:

> While other financial risks that LSEs face can be more easily managed, the market effects of local market power are not as easily hedged and may be pervasive, propagating excess costs on LSEs and ultimately ratepayers. A stringent and effective mechanism for mitigating the exercise of local market power is critical to ensuring efficient market dispatch and pricing.[79]

In particular, the CAISO did not believe market power at any level contributed to the performance of its markets:

> The concern with the bid conduct and market impact approach to LMPM is that whatever thresholds are used in the conduct and impact tests essentially define an acceptable level of market power (*i.e.*, units having local market power will likely bid a penny below the thresholds in order to avoid being mitigated). In contrast, the PJM-like approach provides no such thresholds and therefore provides more effective local market power mitigation. Under the PJM-like approach, units dispatched up to relieve congestion on non-competitive transmission paths are automatically mitigated. It is for this reason that the CAISO is currently only proposing the PJM-like approach for LMPM.[80]

The CAISO explained that its conservative approach reflects its recognition of the asymmetrical economic consequences of its proposed test rather than a preference for over- as opposed to under-mitigation:

> If adequate competition does exist, bid prices are expected by definition to be not too far off the competitive levels, which can be approximated through Default Energy Bids. So, incorrectly

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79 Prepared Testimony of Keith Casey, Exh. ISO-6 at 5 *ll.* 3–7, filed in Docket No. ER06-615-000 (2006).

80 *Id*. at 24 *l.* 17–25 *l.* 2.

> designating a competitive path as non-competitive should not have a significant impact on final prices. However, if adequate competition does not exist and the path is declared as competitive (*i.e.*, false positive), the pivotal supplier will be in a position to raise prices with no local market power mitigation in place. This would clearly have a much greater price distortion impact. [81]

CAISO's endorsement of this approach to mitigation relies in part upon the precedent set by its successful implementation in PJM.

### E. <u>The Performance of TPS Test</u>

The actual evidence about the application of market power mitigation in the PJM markets strongly supports the view that offer capping for local market power is tightly targeted and limited in scope. Despite arguments about how and why the three pivotal supplier test is expected to lead to excessive mitigation, the evidence strongly contradicts those arguments. The State of the Market Reports have documented the relatively small number of units and hours affected by market power mitigation. Levels of offer capping in PJM have been low.[82]

The result of the introduction of the three pivotal supplier test was to limit offer capping to times when the local market structure was noncompetitive and specific owners had structural market power. The analysis of the application of the three pivotal supplier test demonstrates that it is working successfully to exempt owners when the

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81 Prepared Testimony of Keith Casey, Exh. ISO-6 at 59 *l.* 22–60 *l.* 6, filed in Docket No. ER06-615-000 (2006).

82 2007 State of the Market Report, page 19.

local market structure is competitive and to offer cap owners when the local market structure is noncompetitive.

The three pivotal supplier test is applied by PJM on an ongoing basis in order to determine whether offer capping is required to prevent the exercise of local market power for any constraint not exempt from offer capping. The MMU analyzed the results of the three pivotal supplier tests conducted by PJM since its inception.

Overall, the results confirm that the three pivotal supplier test results in offer capping when the local market is structurally noncompetitive and does not result in offer capping when that is not the case. Local markets are noncompetitive when there is a small number of suppliers. The number of hours in which one or more suppliers pass the three pivotal supplier test and are exempt from offer capping increases as the number of suppliers in the local market increases. For example, the regional constraints have a larger number of suppliers and more than 59 percent of the three pivotal supplier tests have one or more passing owners. In contrast, more local constraints have only three or fewer suppliers and therefore are always structurally noncompetitive.

## F. The Completeness of PJM Markets

### 1. RPM

PJM implemented RPM, a significant change to the structure of PJM capacity markets, and the implications of RPM on the overall investment incentives for PJM markets should not be under-emphasized.[83]

The Commission appropriately recognized the implication of PJM's new capacity market design as well as the increasingly sophisticated approach to local market power mitigation.

> [T]he original exemption was predicated on our conclusion that the existing mitigation scheme was not providing just and reasonable compensation to generation.[footnote omitted] But since our July 5, 2005 Order continuing the exemption, improvements have been made to the PJM markets, and the PJM market has changed to such a degree, that our concern with mitigated generators not receiving just and reasonable compensation has been assuaged. The mitigation scheme itself is now more targeted. Generation dispatched during scarcity conditions is now exempt from mitigation and the mitigated bid caps have been increased for those generators that are frequently mitigated. Moreover, as MD PSC argues, the initiation of RPM provides all generators, including the previously construction-exempt generators with a new, additional source of revenue that was not available at the time the exemption was first permitted. PJM filed to propose RPM in 2005, and it was accepted by the Commission in 2006 to be implemented on June 1, 2007.[footnote omitted] Generators eligible for the construction exemption were built before September 30, 2003, prior to the date that RPM was proposed to the Commission. As such, they did not rely on RPM revenues in their decisions to enter the PJM market. In determining to remove the construction exemption, we are

[83] *See supra* footnote no. 45.

> balancing the exempt generators' reliance interest on the exemption as a source of revenue with the need to protect against the potential exercise of market power, and find that given the development of a capacity market, as well as the other changes that reduce the scope of mitigation, the balance has shifted in favor of mitigating these units on the same basis as all other generation in PJM.[84]

### 2. Scarcity Pricing

In conditions of ample supply, a perfectly competitive market consists of an auction among suppliers to meet demand at lowest cost. In conditions where supplies are inadequate, a perfectly competitive market instead becomes an auction to allocate scarce supply. In order for the market to ensure adequate supply over the long-run, it is necessary that suppliers have an opportunity to earn scarcity rents, such that even a marginal supplier has an opportunity to recover its fixed costs and receive a return on investment. Adequate total revenues can be obtained via scarcity pricing in the energy market, via the provision of scarcity revenues in the capacity market (RPM), or a combination of the two. While there is flexibility for market designers to choose among possible sources, PJM markets must provide appropriate opportunities for suppliers to recover scarcity revenues.

The RPM design reflects the recognition that the energy and ancillary services markets cannot by themselves produce adequate revenues for supply, especially in the energy markets lack adequate provisions for scarcity pricing, as is now the case. With the

[84] May 16th Order at P 44.

implementation of RPM, it is not strictly necessary that the energy markets make provision for scarcity pricing because the RPM design itself provides an alternative opportunity for resources to collect scarcity revenues. Because the design of RPM established the parameters of its demand curve based on the cost of new entry net of revenues earned in the energy and ancillary markets, it would also be possible to permit generation owners to recover scarcity revenues entirely from energy markets. A third possibility would be to allow for recovery through some combination of energy and capacity markets.

The development of the RPM design was based on the recognition that this incentive/revenue goal needed to be explicitly included in the capacity market design. The original daily capacity credit market design evolved from the need to have a transparent market mechanism where new retail competitors could obtain capacity in order to meet the requirements of all load serving entities under PJM rules and did not consider revenue issues.

The revenues in the capacity market are scarcity revenues. If the revenues collected in the RPM market are adequate, it is not essential that a scarcity pricing mechanism exist in the energy market. Nonetheless, it would be preferable to have a scarcity pricing mechanism in the energy market because it provides direct, market-based incentives to load and generation, as long as it is designed to ensure that scarcity revenues directly offset RPM revenues.

The energy market can and should be competitive. A competitive market clears based on the marginal cost of the highest cost unit that is producing energy, accounting for the possibility of multiple marginal units in the presence of transmission constraints.

There is no reason to build market power into the design of the energy markets. A complete market design will provide adequate revenues via scarcity revenues in an energy only market or via scarcity revenues provided in the form of capacity payments in a hybrid market design. It is the obligation of every unit that is a capacity resource to make an offer into the Day-ahead Energy Market. The offer into the day energy market should be required to be a competitive offer. The fundamental energy market design should assure all market participants that the outcomes are competitive. This works to the ultimate advantage of all market participants including existing and prospective load and existing and prospective generation. The market rules should explicitly require that offers into the day ahead energy market are competitive, where competitive is defined to be the short run marginal cost of the units. The short run marginal cost should reflect opportunity cost when and where appropriate.

An offer that exceeds short run marginal cost is not a competitive offer in the day ahead energy market. Such an offer assumes the need to exercise market power to ensure revenue adequacy. An offer to provide energy only in an emergency is not a competitive offer in the day ahead energy market. Such a unit should reflect an appropriate outage rather than its availability to compete in the energy market. Capacity market design should reflect the fact that the capacity market is a mechanism for the collection of scarcity revenues and thus reflect the incentive structure of energy markets to the maximum extent possible. For example, if a generation unit does not produce power during a high price hour, it receives no revenues from the energy market. It does not receive some revenues simply for existing, it receives zero revenues. The reason that the unit does not produce energy is not relevant. It does not receive revenues if it does not produce energy even if the reason for non performance is outside management's control. That is the basic performance incentive structure of energy markets. The same performance incentive structure should be replicated in capacity market design. If a unit that is a capacity resource does not produce energy during the hours defined as critical, it will receive no energy revenues for those hours. If a unit defined as a capacity resource does not produce energy during any of the hours defined as critical, it should receive no capacity revenues.

This approach to performance is also consistent with the reduction of administrative penalties associated with failure to meet capacity tests, for example. A hybrid market design can provide scarcity revenues both via scarcity pricing in the energy market and via the capacity market. However, if scarcity revenues are provided in the energy market, there must be an explicit mechanism to remove those revenues from capacity market revenues. This offset must reflect the actual scarcity revenues and not those reflected in forward curves or forecast by analysts from any organization. The absence of such a mechanism is likely to result in an over collection of scarcity revenues as such revenues are episodic and unlikely to be fully reflected in forward curves, even if such curves were based on a liquid market three years forward and reflected locational results, which they do not.

## G. Assessment of Recommendations

In the course of the recently concluded stakeholder process, PJM and other participants have recommended a number of modifications to the TPS test, none of which have merit.

### 1. Modify Screen to Apply Less Frequently

The suggestion that the TPS test is run too frequently misses the point that the TPS test, unlike other market power tests, runs when dictated by actual market conditions. The TPS test is the most sophisticated market power test in operation in large part because the test reflects actual market conditions as defined by the actual power markets. Running the TPS test on an arbitrary schedule rather than one dictated by the actual facts of the market will result in missing market power at times. There is simply no reason to run the TPS test less frequently. The suggestion to run the test less frequently would be similar to suggesting that LMP be defined less frequently. In a real-time LMP market where the LMP is defined every five minutes, it is critical that the market power test reflect the actual market conditions. The suggestion that the results of the TPS test vary or oscillate in some way that does not reflect actual market conditions is completely unsupported by any factual evidence.

### 2. Definition of the Relevant Market

Participants in the working group and PJM have suggested that, in some circumstances, the TPS test does not appropriately define the market for analysis. The suggestion is that the definition of supply in the TPS test may exclude some resources that are considered for potential relief of a constraint. PJM, for example, argues that the 1.5 times clearing price threshold may be too restrictive a definition of the market for purposes of examining the structure of the market.[85] This is their basis for suggesting that a 2.0 threshold may be more appropriate. The Brattle Group opines that geographic markets might more appropriately delineate potential markets than the actual dynamic supply and demand conditions recognized by PJM's market solution software.

Given that the supply directly included as relevant to the market in the TPS test consists of the incremental, effective megawatts of supply that are available at a price less than, or equal to, 1.5 times the clearing price ($P_c$) that would result from the intersection of demand (constraint relief required) and the incremental supply available

[85] PJM Report at 22–24.

to resolve the constraint, PJM's concern regarding the inclusiveness of the TPS test's definition of the market is ill-founded at best. The TPS Test is running as part of PJM's market software and the incremental supply available to solve the constraint is defined by the PJM market software. For PJM's position to be correct, PJM's market software would have to be operating incorrectly or PJM would have to be implementing the TPS test incorrectly. If correct, it would indicate that the some portion of the supply currently included as a potential market solution by the solution software (the point that determines the theoretical shadow price of the constraint ($P_c$) used by the solution software when it runs the TPS test) is either not actually available, is not available to the extent that the software is assuming, or has other bid parameters that should exclude it from consideration as a meaningful competitor in the market for provision of relief of the constraint in question. If this were true, PJM's implementation of the TPS test, and its solution software, would require significant review and modification. The effective supply used by the TPS Test incorporates all relevant supply considered by PJM dispatchers and is, based on the 1.50 multiplier, well in excess of what is needed to relieve the constraint.

It should also be clear that the Brattle Group's suggestion that the relevant market for the relief of constraint might be more accurately defined on the basis of geography, rather than on the basis upon which generation is dispatched in the context of the PJM market is singularly without merit. The TPS test makes explicit and direct use of the incremental, effective MW of supply available to relieve the constraint at a distribution factor (DFAX) greater than, or equal to, the DFAX used by PJM in operations.[86] Only the supply that can be considered relevant to the market in question is included in the TPS test, to the extent that it is incremental, effective megawatts of supply available at a price less than, or equal to, 1.5 times the clearing price ($P_c$) that would result from the intersection of demand (constraint relief required) and the incremental supply available to resolve the constraint. The use of geographic definitions of markets would be arbitrary at best and would bear no relationship to the actual markets in PJM. One of the advantages of the TPS test is that it captures the actual definitions of the markets extremely precisely because it relies on the PJM software that reflects the full electric network reality.

## IV. RECOMMENDATIONS

### A. Retain and Extend the TPS Test

#### 1. Retain the TPS for Local Market Power

Since the Commission allowed the TPS test to become effective on January 27, 2006, as a consequence of the settlement in Docket No. ER03-236-006, PJM has employed

[86] A unit's contribution toward effective, incrementally available supply is based on the DFAX of the unit relative to the constraint and the unit's incrementally available capacity over current load levels, to the extent that the capacity in question can be made available within an hour of the time the relief will be needed. Effective, incrementally available MW from an unloaded 100 MW 15-minute start combustion turbine (CT) with a DFAX of 0.05 to a constraint would be 5 MW relative to the constraint in question. Effective, incrementally available MW from a 200 MW steam unit, with 100 MW loaded, a 50 MW ramp rate and a DFAX of 0.5 to the constraint would be 25 MW.

the TPS test. The Market Monitor believes that it has performed, and has not compromised the competitive results of the PJM Interchange Energy Market.

Application of this test permits a significant degree of additional unfettered competition, but does not apply when there is enhanced risk of an exercise of market power. This test avoids a burdensome, difficult, intrusive and essentially pointless review of the intent of the seller and avoids an arbitrary and counterproductive inquiry into whether an identified exercise of market power has an impact on markets sufficient to arouse concern. The test is easily administered because it is built into the markets software, and requires no exercise of discretion on the part of the PJM or the Market Monitor. The Commission has recognized and appreciated, in particular, the precision afforded by this analytical approach:

> We conclude that because PJM can apply a market power screen on an hourly basis in real time, it is not just and reasonable for PJM to provide a blanket exemption for all hours on the four currently exempt interfaces. Tying the market power screen to a real-time application provides for more precise analyses.[87]

No alternative test has been shown to calibrate the appropriate degree of mitigation or to operate as free from the use of arbitrary, imprecise and theoretically unjustified reference numbers, administrative discretion and intrusive and pointless inquiry into the motivations of market participants.

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87 May 16th Order at P 47.

### 2. Exemptions

In the May 16th Order, the Commission correctly removed that exemptions for certain and generators constructed at a certain time. Allowing these exemptions meant that certain generators at certain locations or of certain vintage could receive returns based upon even extreme exercises of market power. In addition, because this market power set the single market clearing price, these returns also benefitted facilities with no exception based on vintage. The authorization of the units to charge market-based rates depended upon the Commission's expectation that competition or mitigation in the place of competition would produce just and reasonable rates (*see supra* Section IA). As the Commission has recognized, the implementation of RPM has adequately accounted for any failure in PJM's overall market design to ensure appropriate incentives for investment. No market participant yet has demonstrated an inadequate return from PJM markets even without RPM. The Market Monitor believes that the Commission has no obligation to recognize an investor's expectation that its returns will be set by any degree of exercise of market power regardless of the prevailing regulatory paradigm at any given time,[88] and certainly not where the Commission can have confidence that the returns available from the overall market design are sufficient.

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88 *See* Order No. 697 at P 5 ("the Commission may institute a section 206 proceeding to revoke a seller's market-based rate authorization if it determines that the seller may have gained market power since its original market-based rate authorization").

## B. <u>Reform Other Areas of PJM's Overall Market Design</u>

### 1. Retain RPM

The RPM construct should be maintained and improved as it provides scarcity pricing signals required by the markets.

The wholesale power markets, in order to be viable, must be competitive and they must provide adequate revenues to ensure an incentive to invest in new capacity. A wholesale energy market will not consistently produce competitive results in the absence of local market power mitigation rules. This is the result, not of a fundamental flaw in the market design, but of the fact that transmission constraints in a network create local markets where there is structural market power. The local market power mitigation rules reflect a recognition of the fact that local market power will exist in energy markets in a transmission network and needs to be addressed in order to ensure competitive outcomes.

A wholesale energy market will not consistently result in adequate revenues in the absence of a carefully designed and comprehensive approach to scarcity pricing. This is a result, not of offer capping, but of the fundamentals of wholesale power markets which must carry excess capacity in order to meet externally imposed reliability rules.

The RPM design reflects the recognition that the energy markets, by themselves and in the absence of a carefully designed expansion of scarcity pricing, will not result in adequate revenues. The RPM design provides an alternate method for collecting scarcity revenues.

Scarcity revenues to generation owners can come entirely from energy markets or they can come from a combination of energy and capacity markets. The revenues in the capacity market are scarcity revenues.

The development of the RPM design was based on the recognition that this incentive/revenue goal needed to be explicitly included in the capacity market design. The original daily capacity credit market design evolved from the need to have a transparent market mechanism where new retail competitors could obtain capacity in order to meet the requirements of all load serving entities under PJM rules and did not consider revenue issues.

### 2. Reform the Scarcity Pricing Provisions

If the revenues collected in the RPM market are adequate, it is not essential that a scarcity pricing mechanism exist in the energy market. Nonetheless, it would be preferable to have a scarcity pricing mechanism in the energy market because it provides direct, market-based incentives to load and generation, as long as it is designed to ensure that scarcity revenues directly offset RPM revenues.

The energy market can and should be competitive. A competitive market clears based on the marginal cost of the highest cost unit that is producing energy, accounting for the possibility of multiple marginal units in the presence of transmission constraints. There is no reason to build market power into the design of the energy markets. A complete market design will provide adequate revenues via scarcity revenues in an energy only market or via scarcity revenues provided in the form of capacity payments in a hybrid market design.

## V. CONCLUSION

The Market Monitor respectfully requests that the Commission afford due consideration to these comments as it completes its investigation of PJM's TPS test for local market power.

Respectfully submitted,


Joseph E. Bowring

Independent Market Monitor for PJM

President
Monitoring Analytics, LLC
2621 Van Buren Avenue, Suite 160
Valley Forge Corporate Center
Eagleville, Pennsylvania 19403
610-271-8051
*joseph.bowring@monitoringanalytics.com*

Jeffrey W. Mayes

Monitoring Analytics, LLC

General Counsel
2621 Van Buren Avenue, Suite 160
Valley Forge Corporate Center
Eagleville, Pennsylvania 19403
(610) 271-8053
*jeffrey.mayes@monitoringanalytics.com*


Dated: October 6, 2008

## CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Eagleville, Pennsylvania,
this 6th day of October, 2008.

Jeffrey W. Mayes

General Counsel
Monitoring Analytics, LLC
2621 Van Buren Avenue, Suite 160
Valley Forge Corporate Center
Eagleville, Pennsylvania 19403
(610) 271-8053
*jeffrey.mayes@monitoringanalytics.com*