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April 25, 2003

ATTACHED PREPARED TESTIMONY AND ACCOMPANYING SCHEDULES CONTAIN PRIVILEGED INFORMATION AND SHOULD NOT BE RELEASED

Honorable Magalie R. Salas
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E. Room 1A
Washington, D.C. 20426

Re: Reliant Energy Mid-Atlantic Power Holdings, LLC v. PJM Interconnection, L.L.C.,
Docket No. EL03-116-000

Dear Ms. Salas:

PJM Interconnection, L.L.C. ("PJM"), submits for its Answer to the Complaint of Reliant Energy Mid-Atlantic Power Holdings, LLC ("Reliant"), in the proceeding captioned above.

1. Request for Privileged Treatment of Documents

Pursuant to Section 388.112 of the Commission's regulations, 18 C.F.R. § 388.112, PJM requests that portions of the Prepared Direct Testimony of Joseph E. Bowring on behalf of PJM Interconnection, L.L.C., as well as Schedules JEB-1, JEB-2, JEB-3 and JEB-4 attached to that testimony (collectively designated and referred to here as "Exhibit PJM-1"), be treated as privileged and confidential and not be disclosed to the public. The privileged portions of Exhibit PJM-1 consist of data, and/or discussion and analysis of such data, regarding fixed and variable costs of certain generating units owned by the complainant, Reliant, in the PJM region and regarding revenues Reliant has received during selected periods from transactions involving those units in PJM's capacity, energy and ancillary services markets. This kind of information typically is kept confidential by individual market participants, and thus, pursuant to section 18.17.1 of the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. ("PJM Operating Agreement"), PJM maintains it as confidential. Public disclosure of this information is not in the public interest because such disclosure might cause competitive harm to Reliant.

In accordance with the Commission's Rule 213(c)(5)(i), 18 C.F.R. § 385.213(c)(5)(i), PJM submits the original and three complete copies of this transmittal letter, its Answer to the Complaint and all attachments, including an unredacted original and three unredacted copies of Exhibit PJM-1. The first page of the Answer and the cover pages of each component of Exhibit PJM-1 (Mr. Bowring's testimony and Schedules JEB-1, JEB-2, JEB-3 and JEB-4) boldly indicate that PJM's submission and each pertinent component thereof contains privileged information that should not be released. In addition, the information for which PJM seeks privileged treatment is identified within the unredacted original and each unredacted copy of Mr. Bowring's testimony; PJM seeks privileged treatment of each of Schedules JEB-1, JEB-2, JEB-3 and JEB-4 in its entirety, so the unredacted originals and copies of those documents do not include such shading. As further required by 18 C.F.R. § 385.213(c)(5)(i), PJM also submits 11 copies of this transmittal letter, its Answer to the Complaint and all attachments, including redacted copies of Exhibit PJM-1 that exclude all privileged material.

Pursuant to 18 C.F.R. § 388.112(b)(1)(iv), PJM designates the following person to be contacted regarding the request for privileged treatment of the identified portions of Exhibit PJM-1:

Barry S. Spector
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2. <u>Request for Waiver Regarding Proposed Confidentiality Agreement</u>

In connection with the above request for privileged treatment of portions of the enclosed material, PJM requests that the Commission waive its Rule 213(c)(5)(ii), 18 C.F.R. § 385.213 (c)(5)(ii), that requires a respondent that submits an answer with a request for privileged treatment of confidential material to serve with the redacted copy of its pleading a proposed form of protective agreement. As noted above, the material for which PJM is seeking privileged treatment is data, and/or discussion and analysis of such data, regarding fixed and variable costs of certain generating units owned by the complainant, Reliant, in the PJM region and regarding revenues Reliant has received during selected periods from transactions involving those units in PJM's capacity, energy and ancillary services markets. Because this kind of information typically is kept confidential by individual market participants, PJM maintains it as confidential information pursuant to section 18.17.1 of the PJM Operating Agreement.

PJM seeks waiver of the requirement to tender a proposed protective agreement because PJM lacks authority to enter into an agreement to disclose confidential information of or regarding one of its Members to third parties, including other Members. Specifically, paragraph (b) of section 18.17.1 of the PJM Operating Agreement prohibits PJM from disclosing such confidential information. Accordingly, it would be inappropriate for PJM to offer, through a proposed protective agreement, to disclose the confidential information included in its Answer when it serves its pleading. PJM therefore requests that the Commission waive Rule 213(c)(5) in this instance to the extent that it would require PJM to tender a proposed protective agreement to the parties to this proceeding.

PJM wishes to advise the Commission, however, that since all of the confidential material in Exhibit PJM-1 for which PJM herein seeks privileged treatment relates only to the complainant, Reliant, PJM today is delivering to counsel for Reliant an unredacted copy of Exhibit PJM-1. PJM's request for waiver of Rule 213(c)(5) therefore will not limit Reliant's access to all information that PJM has submitted to the Commission.

Respectfully submitted,

Barry S. Spector
Michael J. Thompson

Counsel for
PJM Interconnection, L.L.C.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Reliant Energy Mid-Atlantic Power Holdings, LLC, Complainant,	)	
v.	)	Docket No. EL03-116-000
PJM Interconnection, L.L.C., Respondent.	)	

ANSWER OF
PJM INTERCONNECTION, L.L.C.
TO COMPLAINT OF
RELIANT ENERGY MID-ATLANTIC POWER HOLDINGS, LLC

Pursuant to Section 206 of the Federal Power Act ("FPA"), 16 U.S.C. § 824e (1994); Rules 206 and 213 of the Commission's Rules of Practice and Procedure, 18 C.F.R. §§ 385.206, 385.213 (2002); and the Commission's notices in this proceeding of April 7 and April 18, 2003, PJM Interconnection, L.L.C. ("PJM") submits its answer to the complaint filed on April 2, 2003, by Reliant Energy Mid-Atlantic Power Holdings, LLC ("Reliant"). For the reasons explained below and in the attached, supporting testimony of Joseph E. Bowring, Manager of PJM's Market Monitoring Unit ("MMU"), the complaint is without merit, and the Commission should deny the relief Reliant seeks and dismiss the complaint with prejudice.

I. Introduction

Reliant's complaint alleges that PJM's present caps on offers to sell by "must-run" generating units, i.e., units with local market power that are dispatched out of economic merit order to ensure reliability of service, are unjust and unreasonable because, according to Reliant, they provide Reliant with "insufficient" revenues from operation of 10 particular combustion turbine generating units owned by Reliant. Reliant further asserts that the present offer caps do not provide proper price signals to potential investors in new generation resources. Reliant asks the Commission to establish a new offer cap for the identified Reliant units, based on a modified version of the "proxy CT" that ISO New England has implemented. Reliant proposes that this new offer cap be made effective on June 1, 2003, and remain in effect until an existing PJM stakeholder group develops, and PJM implements, long-term changes to PJM's current offer caps for must-run units.

The Commission should deny the complaint in its entirety. Most remarkably, even though Reliant's claim of "insufficient" revenues for the 10 named units is the principal foundation of its complaint, Reliant conspicuously omits even the tiniest shred of information about the units' actual costs or revenues. For these and other reasons explained below and in Mr. Bowring's accompanying testimony, Reliant has failed to carry its initial burden under Section 206 of the Federal Power Act[1] of proving that PJM's existing offer caps are unjust and unreasonable. Therefore, Reliant cannot prevail and the Commission should dismiss the complaint with prejudice. Even assuming that Reliant somehow could establish that PJM's existing offer caps are unjust and unreasonable, its complaint still fails to justify the alternative, proxy CT offer cap that it proposes. At the very least, the relief Reliant proposes presents genuine issues of material fact, with respect to both propriety of, and the validity of the cost assumptions used in,

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[1] 16 U.S.C. § 824e.

Reliant's proposed proxy CT formula. Therefore, even if the Commission were to reach the question of remedy (which it should not), it should convene an evidentiary hearing to resolve relevant factual issues before ordering any remedy.

II. Correspondence And Communications

Correspondence and communications with respect to this filing should be sent to, and PJM requests that the Secretary include on the official service list, the following:

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III. Background

A. Local Market Power Mitigation in the PJM Region

Section 6 of Schedule 1 of the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. ("Operating Agreement") prescribes rules applicable to generation resources in the PJM region that have or may have local market power, i.e., reliability must-run units. These provisions apply to units on which construction commenced prior to July 9, 1996, and which, "as a result of transmission constraints, [PJM] determines, in the exercise of Good Utility Practice, must be run in order to maintain the reliability of service in the PJM Control Area and PJM West Region."[2] Section 6.4 of Schedule 1 provides that, at any time that PJM determines that such a unit must be dispatched out of economic merit order "to maintain system reliability as a result of limits on transmission capability," the prices offered by such resources for sale of their

2 PJM Operating Agreement, Schedule 1, Section 6.1.

energy shall be capped. Section 6.4.2 states that the offer cap for each such unit must be one of three specified amounts:

> (i) The weighted average Locational Marginal Price at the generation bus at which energy from the capped resource was delivered during a specified number of hours during which the resource was dispatched for energy in economic merit order, the specified number of hours to be determined by the Office of the Interconnection and to be a number of hours sufficient to result in a price cap that reflects reasonably contemporaneous competitive market conditions for that unit;
>
> (ii) The incremental operating cost of the generation resource as determined in accordance with Schedule 2 of this Agreement and the PJM Manuals, plus 10% of such costs; or
>
> (iii) An amount determined by agreement between the Office of the Interconnection and the Market Seller.

It is only when transmission constraints, in the absence of the offer cap, would allow the unit to exercise local market power that the cap limits the price the generator is paid. Even then, however, units that are subject to the offer caps are paid the <u>higher</u> of their capped offer price or the market-determined locational marginal prices ("LMP"). Therefore, if market conditions lead to prices above a must-run unit's offer cap, the unit is paid the prevailing market price.

These provisions have been part of the Operating Agreement since it was initially filed with the Commission in 1997 as part of PJM's request for approval as an independent system operator. <u>See</u> <u>Atlantic City Elec. Co.</u>, 86 FERC ¶ 61,248, at 61,898-99, 61,902-04, <u>order on reh'g</u>, 88 FERC ¶ 61,039, at 61,092 (1999). Therefore, the offer caps that apply today to the Reliant units are the same caps that have always applied to these units and were in place when Reliant purchased the units from Sithe Energy in 2000. See Complaint at 2.

As Mr. Bowring explains in his testimony, the purpose of the offer caps is to restrain the exercise of local market power by generators whose units must be dispatched out of economic merit order when transmission constraints require running the units to ensure reliability of service to customers. In the absence of the offer caps established by the Operating Agreement, when transmission in a portion of the system is constrained, generation resources in the affected load pocket could extract monopoly profits because the transmission constraint requires PJM to call upon the units to operate in order to maintain reliable service in the affected area. Bowring testimony at 2-3.

B. Mitigation Applicable to Reliant's Units

Reliant's complaint addresses 10 of approximately 29 combustion turbine generating units in the PJM region that Reliant purchased in 2000 from Sithe Energy. These 10 units are frequently dispatched out of economic merit order, and at such times each of them is subject to an offer cap equal to its incremental operating cost plus 10%.

As noted, the same offer cap applied to each of the 10 units when Reliant purchased them. In November 2000, however, Reliant approached PJM to discuss concerns about the offer caps applicable to its units. Mr. Bowring asked Reliant to identify the particular units to which its concerns related and to provide the MMU with information to support Reliant's assertion that it was not receiving adequate compensation related to the units. Reliant never provided such information. Bowring testimony at 9-10. This information gap continues. Reliant's complaint studiously avoids revealing anything about Reliant's actual costs or actual revenues for the 10 units that it claims require relief from their longstanding offer caps.

PJM's discussions with Reliant subsequently migrated to consideration of certain units that were subject to environmental conditions that restrict the number of hours they may operate each year. Reliant's concern was that, when PJM calls on these units to run out of economic merit order during winter months, Reliant is denied the opportunity to run the units (under economic dispatch, based on the units' offer prices) during summer months, when market prices generally are higher. Bowring testimony at 10.

To address this concern, the MMU entered into an agreement with Reliant in August 2001 that increased the offer cap applicable to the environmentally-restricted Reliant units. The agreement added an opportunity cost component to the incremental cost plus 10% offer cap for those units. The opportunity cost factor was based on an option valuation model that Reliant developed and to which the MMU, after review and some mutually acceptable modifications, agreed. Although Reliant indicated to Mr. Bowring that the calculated option value underlying the opportunity cost adder was smaller than Reliant had anticipated, it nevertheless did not dispute that the adder was correctly determined. The August 2001 agreement, remained in effect until Reliant unilaterally terminated it a few days before it filed its complaint in this proceeding. Bowring testimony at 10-11. Thus, all 10 of the units that are the subject of Reliant's complaint are again subject to the incremental cost plus 10% offer cap when they are dispatched out of economic merit order.

C. Ongoing PJM Stakeholder Process

Under PJM's rules, Reliant at any time, with the support of just four other members of PJM, could have established a User Group of PJM's Members Committee to address Reliant's apparent concerns with PJM's prevailing offer caps for must-run units.[3] Reliant did not initiate any such effort. Nevertheless, PJM's market monitor on his own

[3] See PJM Operating Agreement, Section 8.7.

initiative established PJM's Local Market Power Mitigation Working Group ("LMPMWG") in September 2002 to evaluate the existing offer caps and to consider changes to them. Bowring testimony at 12.

The LMPMWG has met approximately biweekly since its initial meeting on September 26, 2002. The group includes representatives of all stakeholder segments and has undertaken a close examination of the complex issues that local market power presents, including presentations by speakers from outside PJM and preparation and discussion of a variety of issue papers and presentations. Id. at 12-13.

As the group's work progressed, it became apparent that it would be unable to develop a permanent, new framework for mitigating local market power in time for implementation for the 2003 summer peak season. The group therefore developed and, on April 14, 2003, agreed to an Interim Solution to be implemented in 2003. The Interim Solution includes the following terms:

For any unit that:

Was cost capped in 2002 more than 80% of its operating hours;
Was cost capped in 2002 more than 50% and less than 80% of its operating hours;
Operated more than 200 hours in 2002;
Was required for reliability; and
Did not cover its fixed costs with other revenues,

The Market Monitoring Unit will negotiate modified cost caps to include:

An adder of \$40 per MWh for any unit that was cost capped more than 80% of its run hours during 2002 and operated for more than 200 hours in 2002; or
An adder of \$20 per MWh for any unit that was cost capped more than 50% of its run hours and less than 80% of its run hours during 2002 and operated for more than 200 hours in 2002; or
An adder based on 200 hours for any units that was cost capped more than 50% of its run hours and ran less than 200 hours; and
An agreement that the owner of the unit will maintain the unit consistent with good utility practice.

See Bowring testimony at 14-15; Ex. PJM-2.

The Interim Solution will be implemented by agreements with generators pursuant to Section 6.4.2(iii) of Schedule 1 of the PJM Operating Agreement. The LMPMWG further has agreed that it will develop a long-term solution for mitigating local market power by the end of 2003 and that, should the group fail to reach an agreement, the MMU will file a proposal for permanent mitigation measures for resolution by the Commission.

On April 16, 2003 the PJM Energy Market Committee, by a vote of 29 in favor and 4 opposed, with 14 abstentions, endorsed the Interim Solution. Bowring testimony at 13. By letter dated April 22, 2003, the MMU advised all PJM members of the terms of the Interim Solution and invited any generators interested in entering into agreements to take advantage of the Interim Solution's modified offer caps for 2003 to contact the MMU.[4]

IV. Reliant's Complaint Is An Unjustifiable Attempt To Circumvent The PJM Stakeholder Process.

PJM has offered Reliant, for all of its offer-capped units, the same terms that are now included in the Interim Solution. However, Reliant declined to accept those terms and instead has filed its complaint in this proceeding. Bowring testimony at 11. Reliant claims that it is pursuing the complaint because the LMPMWG was unable to develop a new offer cap approach that could be implemented for the 2003 summer season. Reliant Transmittal at 4. However, on March 29, 2003 -- before Reliant filed its complaint -- the LMPMWG discussed the final version of the Interim Solution and, based on the substantial support for the proposal, decided to take a final vote on the measure at its next

4 A copy of the MMU's April 22 letter regarding the Interim Solution is attached to this answer testimony as Exhibit PJM-2.

meeting on April 14. Reliant knew when it filed the complaint that the Interim Solution was forthcoming and that it would be available for the upcoming summer.

Reliant no doubt is disappointed that its views have not prevailed in the LMPMWG's deliberations (at least not with respect to the short-term Interim Solution). Nevertheless, its complaint's principal premise -- that the LMPMWG could not develop a revised must-run offer cap for 2003 -- is erroneous. In fact, contrary to Reliant's claims, the LMPMWG, after several months of studying and debating the relevant issues, has developed and approved an interim modification of PJM's present offer caps that applies throughout the PJM region.

The Interim Solution is the result of an open process in which the views of all stakeholders, including Reliant, were heard and considered. It has widespread support, as indicated by the EMC vote on April 16. Reliant does not even claim, much less demonstrate, that even PJM's current offer caps, let alone the Interim Solution's higher caps, are not compensatory or that Reliant cannot keep its units in operation without the immediate, far more generous relief that it demands. Indeed, as noted, Reliant carefully has avoided telling the Commission (or PJM) anything about the costs or revenues of Reliant's units. Moreover, the LMPMWG is committed to developing a new long-term mitigation approach prior to November 30, 2003. Reliant's complaint, therefore, is premature at best and its attempt to circumvent PJM's stakeholder process is wholly unjustified.

Stakeholders' incentives to participate actively in regional working groups and committees will be substantially diminished if the Commission permits disgruntled parties to obtain customized exceptions to the outcome of such processes. The damage will be especially great if such parties can obtain special relief, as Reliant hopes here, even before an ongoing regional process is finished.

While the Commission retains ultimate authority to review all terms and conditions affecting jurisdictional services, the importance of regional stakeholder forums in resolving the myriad operational and administrative issues that arise in the ongoing evolution of ISOs and RTOs and the markets they administer should not be underestimated. To allow a single party to obtain from the Commission more favorable, individualized terms than it was able to achieve through stakeholder deliberations, as Reliant seeks through the present complaint, would undermine independent regional entities' stakeholder processes. The Commission therefore should deny Reliant's complaint as a precipitate and unwarranted effort to circumvent the PJM stakeholder process and the LMPMWG's Interim Solution.

IV. Reliant Fails To Prove That PJM's Must-Run Offer Caps Are Unjust And Unreasonable.

Section 206 of the FPA imposes a two-pronged burden of proof on those who seek to change a utility's approved tariff provisions or other terms of service. See 16 U.S.C. § 824e; W. Res., Inc. v. FERC, 9 F.3d 1568 (D.C. Cir. 1993). Accordingly, Reliant's threshold requirement is to demonstrate that the rate or practice that it challenges is unjust and unreasonable, unduly discriminatory, or otherwise unlawful under the Act. Reliant has failed to carry this burden.

A. Reliant Provides No Foundation For Its Claim Of "Insufficient" Revenues.

Reliant contends that PJM's current offer caps are unjust and unreasonable because, according to Reliant, must-run generators are unable to obtain sufficient revenues to afford them an opportunity to earn a reasonable return on their investments.

In support of this assertion, however, Reliant principally relies on its representation that it received only $5 million of revenue net of fuel costs for the disputed units in 2002. See Reliant Transmittal at 5. Even if Reliant's revenue allegations are accepted (they cannot be without investigation), Reliant's position nevertheless is untenable.

The fact that Reliant may have had poor results on some of its units in one particular year does not of itself establish a flaw in PJM's local market power mitigation rules. Reliant offers no information (not even on a confidential basis) regarding either its operating costs (other than fuel) or its undepreciated capital investment for its 30-year-old units. Nor does it explain why the Commission should even consider only the (undocumented) performance of the 10 units Reliant chose to include in its complaint rather than Reliant's overall financial results from all of the 29 units that it bought together from Sithe in 2000. Moreover, even assuming that Reliant's $5 million in 2002 revenues in excess of fuel costs for the disputed 10 units did not provide a reasonable return for those units for that one year, Reliant never even asserts, much less explains, why the Commission should consider that single year's experience either to be representative of Reliant's results in other years (past and future) or, more importantly, sufficient of itself to satisfy Reliant's Section 206 burden of proof. To the contrary, Reliant's own admission that the PJM capacity and energy markets were depressed in 2002 relative to previous years (Reliant Transmittal at 3) underscores the lack of merit of Reliant's claims.

In fact, Mr. Bowring demonstrates that prices for both capacity and energy in PJM markets in previous years were substantially higher than in 2002. Reliant's 2002 revenues from the 10 units in question would have been significantly greater if 2002 capacity and energy prices had held close to their 2001 levels. Bowring testimony at 26-

27. Reliant itself admits that it expected to receive reasonable revenues under its 2001 agreement with the MMU, but, Reliant asserts, lower market prices for energy and capacity created a "unique problem" for it in 2002. Reliant Transmittal at 3.

What Reliant describes, however, is simply market risk. As Mr. Bowring explains, all generators in PJM realized lower revenues in 2002 than in previous years. Such a downturn in the market is simply that – and certainly not an indication of a flaw in PJM's offer caps for must-run units. See Bowring testimony at 25-27. Moreover, contrary to what its complaint seems to suggest, Reliant has no right to earn any particular amount of revenue from any of its units and certainly has no right to higher prices for its must-run hours of operation in order to obtain some, self-prescribed, minimum return on investment or to replace revenues that the generally lower market prices in 2002 may have prevented it from earning.

The development of the Interim Solution further underscores Reliant's failure of proof. The Interim Solution would add $40 per MWh to operating costs to determine the offer caps for most of Reliant's units during must-run hours. Therefore, even if 2002's depressed energy and capacity prices continue through 2003, entering into a must-run agreement based on the Interim Solution would provide Reliant with significantly more revenue than it obtained in 2002. The availability of such immediate relief, combined with Reliant's failure to provide any evidence to support its revenue "insufficiency" claim, compels the conclusion that Reliant has not demonstrated that the offer caps available to it under the Interim Solution are unjust and unreasonable.

B. Reliant's "Price Signal" Argument Also Is Unfounded.

Reliant's assertion that the present must-run offer caps do not provide accurate price signals likewise is unpersuasive. Contrary to Reliant's claim, PJM's offer caps do not interfere with scarcity pricing. In any event, there generally are no scarcity conditions when Reliant's 10 units operate under these offer caps. Bowring testimony at 35. Even must-run units are paid the higher of the market LMPs or their respective offer caps. PJM Operating Agreement, Sched. 1, § 6.4.1(c); Bowring testimony at 4. Therefore, aggregate market scarcity can lead to high LMPs, which in turn signal the need for, and the potential value of, new investment to the marketplace. The offer caps merely prevent must-run units from exercising the local market power that they enjoy due to transmission constraints. Bowring testimony at 3.

C. Contrary To Reliant's Assertion, The Commission Has Not Indicated Disapproval of PJM's Present Offer Caps.

Reliant also errs in suggesting that the Commission has declared that basing offer caps for mitigation of local market power on incremental cost plus 10% is "inappropriate." Reliant Transmittal at 4. Reliant takes out of context the passage on which it relies in paragraph 58 of Midwest Independent System Operator, Inc., 102 FERC ¶ 61,280 (2003) ("Midwest").

In the relevant portion of Midwest, the Commission addressed issues related to the Midwest ISO's proposed thresholds for establishing price caps to mitigate local market power in what the ISO calls "Broad Constrained Areas," or "BCAs." BCAs are not load pockets. Instead, the Commission explained, the Midwest ISO defines a BCA as:

> 'an electrical area in which sufficient competition usually exists even when one or more transmission constraints are binding, but in which a transmission constraint can result in substantial Locational Market Power under certain market or operating conditions.' According to the Midwest ISO, in the BCAs market power concerns would be episodic and related to particular load conditions, outages, or other system conditions that are likely to be difficult to catalog in advance.

Id. at P 48 (footnote omitted). The Midwest ISO proposed significantly less stringent thresholds for imposing market power mitigation in BCAs than those it proposed for load pockets, or "Narrow Constrained Areas." See id. at P 59-62.[5]

A group of intervenors calling itself the Midwest TDUs argued in Midwest that the BCA thresholds were too lax. The TDUs contended that the conduct thresholds "should be no higher than 10 percent above a properly calculated reference level" even for BCAs, the areas that "are anticipated to be competitive except for rare occasions." Id. at P 53, P 58. It was in response to the Midwest TDUs' position that the Commission made the statement that Reliant emphasizes in its complaint: "we agree with the Midwest ISO that implementing a variable cost, plus 10 percent, mechanism for all units in the Midwest ISO footprint would upset the balance between the need to mitigate market power and the need to avoid unwarranted market intervention." Id. at P 58 (emphasis added). However, Reliant's suggestion that this statement supports its complaint is mistaken.

Reliant overlooks that the Commission only held that a simple offer cap, "for all units in the Midwest ISO footprint," was inappropriate. Imposing bid caps of variable cost plus 10% for all units in any region certainly would tip the scales unreasonably toward "unwarranted market intervention." But PJM does not employ incremental cost plus 10% for that purpose. Instead, PJM relies on that formula only to establish offer caps to mitigate local market power of units that are dispatched out of economic merit order

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5 As defined by the Midwest ISO, "A Narrow Constrained Area (NCA) or load pocket is ... an area in which resources capable of relieving a binding [transmission] constraint are owned or controlled by a limited number of suppliers, defined initially as fewer than three suppliers." Id. at P 59 (footnote omitted).

due to transmission constraints. This is significantly different from the Midwest TDUs' proposed threshold that the Commission rejected in Midwest and, equally important, is an approach that the Commission has reviewed and approved for the PJM region. See PJM Interconnection, LLC, 86 FERC at 61,898-99. Therefore, contrary to Reliant's suggestions, nothing in paragraph 58 of Midwest supports Reliant's contention that PJM's present offer caps based on incremental cost plus 10% are unjust and unreasonable.

What is more, Reliant purchased units included in its complaint in 2000 fully aware of PJM's offer caps. That Reliant may not have realized its revenue projections in 2002 due to declining market prices simply is no reason for the Commission to change PJM's rules.

V. Even If PJM's Current Offer Caps Could Be Found Unjust And Unreasonable, Reliant Fails To Establish That Its Proposed Proxy CT Remedy Is Just And Reasonable.

The second prong of the dual burden of proof prescribed by Section 206 of the FPA requires a proponent of change to prove that the rate or practice that it advocates to replace the existing terms of service is just and reasonable. Reliant's failure in this case to carry its initial burden, as described in Section IV above, renders moot in this case the second portion of the Section 206 inquiry. But even if Reliant had justified a finding that PJM's present offer caps for must-run units are unjust and unreasonable (which it has not), its complaint still would fail. Reliant has not demonstrated that its proposed alternative offer cap, its modified version of ISO New England's proxy CT formula, is just and reasonable.

A. Reliant Unjustifiably Disregards The Conditions For Which The Commission Has Approved The Proxy CT Formula.

Reliant disregards several aspects of the Commission's recent approvals of proposals by ISO New England and by the Midwest ISO to base their price caps for mitigation of must-run generators' local market power on the estimated capital costs of a new combustion turbine generator, a so-called "proxy CT."[6] Reliant simply discards criteria for application of the proxy CT formula that were important, limiting components of the proposals the Commission approved. The absence of these elements is fatal to Reliant's proposed relief.

For example, Reliant does not even mention that both ISO New England and the Midwest ISO apply the proxy CT formula as mitigation for local market power only in formally defined, chronically congested areas.[7] In both regions, such areas must be identified and defined through stakeholder processes and, in New England, the Commission also required a filing for its approval of not only the definitions of the Designated Congestion Areas, but also the proxy CT thresholds that the ISO calculated for each of those areas. Nevertheless, Reliant includes no such criteria or procedures in its proposal.[8]

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6 See New England Power Pool, 100 FERC ¶ 61,287, at P 30-46, order on reh'g, 101 FERC ¶ 61,344, at P 14-21 (2002) ("New England"); Midwest, at P 58-73.

7 ISO New England refers to these as "Designated Congestion Areas," while Midwest ISO calls them "Narrow Constrained Areas." See New England, 100 FERC ¶ 61,287 at P 32; Midwest at P 59.

8 For reasons explained below, adding such elements would not salvage Reliant's proxy CT alternative in any event. There are no areas in PJM where must-run units would be eligible for proxy-based offer caps under the terms described in either New England or Midwest.

Reliant thus establishes neither any basis for the Commission to disregard, with respect to PJM or Reliant's units, the conditions for application of proxy-based offer caps that it previously approved, nor that Reliant's units satisfy those criteria. Reliant likewise does not demonstrate that its units operate in defined, chronically congested areas comparable to ISO New England's DCAs or the Midwest ISO's NCAs. Nor could it.

First, such a showing is not possible because there are no chronically congested areas in PJM that would trigger application of proxy-based offer caps in any event. See Bowring testimony at 32-33. Second, Reliant errs in its contention that its units' proportionally high offer capped run hours in 2002 alone demonstrate that the units are located in areas of chronic congestion. To the contrary, as Mr. Bowring shows in his testimony, most of the offer-capped hours in 2002 for the Reliant units were not due to chronic congestion. Instead, they were attributable to the destruction by fire of the Hunterstown 500/230 kV transformer in August, 2002 and other local transmission upgrades reduce congestion in the area. Bowring testimony at 17-18. Replacement of that transformer, as well as upgrading of another, 230/115 kV transformer in the same area, will remedy that situation by approximately mid-2003. Id.

Rather than grappling with the critical facts, Reliant simply grabs for the brass ring, urging the Commission to approve new offer caps in amounts ranging, by Reliant's own calculations, from \$193 to \$214 per MWh, that would apply to all 10 of the units Reliant included in its complaint during all of their offer-capped run hours. The arbitrary relief Reliant advocates would unjustifiably insulate its units from market risk and would permit it to exercise its local market power to extract substantial monopoly rents from consumers in the PJM region.

B. Reliant Does Not Demonstrate That The Proxy CT Approach Is Warranted For The PJM Region.

Reliant further errs by disregarding important differences between the PJM region and the ISO regions for which the Commission has accepted the proxy CT methodology. For example, ISO New England recently filed with the Commission a proposal to designate areas encompassing approximately one-third of all load in its region as DCAs. PJM has no areas comparable to ISO New England's DCAs. In addition, overall market revenues in New England generally have been inadequate to provide reasonable returns to generators, so the ISO has entered into RMR contracts with numerous generators to ensure that they do not retire or mothball generation capacity. Circumstances in the PJM region are much different. PJM's market monitor has concluded, based on a Net Revenue Test, that generators in PJM consistently have obtained market revenues sufficient to sustain operations and provide return on investment. Bowring testimony at 25-26, 33.

The Midwest ISO, for its part, does not propose to have a capacity market when it commences market operations, so generators within its footprint apparently will not realize capacity-related revenues. Using the proxy CT method to provide higher offer caps for units with local market power therefore is arguably more appropriate in the Midwest ISO than in PJM, where there is a well-established capacity market that has historically been a significant source of revenue for generators of all types.

These important differences between PJM and ISO New England and between PJM and the Midwest ISO highlight the baselessness of Reliant's attempt simply to stamp on PJM the proxy CT approach that ISO New England and the Midwest ISO use. Reliant's disregard for such material differences among regional markets demonstrates again that it has not met its Section 206 burden of proof.

C. Reliant Does Not Establish That The Cost Elements Of The Proxy Formula Are Reasonable.

The proxy CT formula that the Commission accepted for ISO New England was premised on estimated capital costs for a new combustion turbine generator. ISO New England obtained this estimate from its consultant, e-Acumen, Inc., which, in turn, developed it from information it gathered regarding the costs of four projects in the New England area that obtained financing in 2001.[9] Reliant unquestioningly employs the same cost information in the proxy CT formula that it advocates here for its units. Reliant provides no evidence, however, that the costs underlying the e-Acumen estimates are valid today or are valid in the PJM region. These omissions further undermine Reliant's contention that its proposed proxy CT offer cap is a just and reasonable alternative to PJM's current caps.

Two of the most important factors in e-Acumen's derivation of the estimated cost of a new combustion turbine in 1991 were the installed cost per kW of capacity and the cost of financing for the debt portion of the assumed project capital structure. According to e-Acumen's report to ISO New England, the average installed (capital) cost of the four 2001 projects for which it obtained information was $413/kW and the annual rate of interest on bank debt for the projects ranged from 8.5% to 9.1%. For purposes of its complaint, Reliant assumes, but offers no evidence to support the premise, that the factors e-Acumen used in its analysis of 2001 costs remain reasonably representative of current costs.

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9 See e-Acumen, Inc., Final Report – June 11, 2002 at 3-6 (Attachment 5 to New England Power Pool and ISO New England, Inc. – NEPOOL Standard Market Design, Vol. I of II, Docket No. ER02-2330-000 (July 12, 2002)).

This omission is a significant defect in Reliant's proposal. It seems reasonable, for example, to believe that prices for gas combustion turbines, and perhaps the cost of debt as well, are materially lower today than they were even two years ago, when the projects that e-Acumen reviewed were financed. It is general knowledge that the credit crisis in energy markets since the demise of Enron Corporation has significantly reduced the pace of development of new generation resources. Since most new generation plants use gas-fired combustion turbines, cancellations and deferrals of projects, according to numerous trade press reports, have significantly reduced overall demand for gas-fueled turbines. See Ex. PJM-3. Such lower demand clearly supports the view that turbine prices have fallen since e-Acumen gathered the 2001 cost information it used in its report.

Although circumstances affecting this factor are less clear, there likewise is reason to believe, as Mr. Bowring further testifies, that the cost of debt financing available to generation developers is lower than that reflected in e-Acumen's estimates. Certainly, prevailing interest rates today are significantly lower than in 2001; for example, data published by the Federal Reserve Board and presented in Exhibit PJM-4 submitted with this answer show that the prime rate charged by major U.S. banks declined from approximately 7% in 2001 to around 4.25% currently. However, the effects of other factors are less discernible. For example, the well-publicized financial problems of many merchant generators and other energy-related companies, as well as generally lower prevailing electricity prices, may lead banks to perceive somewhat greater market risk in financing power plants today than they anticipated in 2001.

Reliant's disregard for market changes such as these is unexplained, unjustified, and reveals that there is foundation for its contention that offer caps for its PJM units based on the e-Acumen 2001 proxy cost estimates for New England would produce just and reasonable prices for energy produced by those units during offer-capped hours. Accordingly, even if the Commission had to reach the second prong of the Section 206 test for Reliant's complaint (which it does not), it would have to reject Reliant's proxy proposal.

D. The Proxy CT Formula Is Flawed.

Reliant likewise overlooks several important defects of the ISO New England proxy CT approach on which Reliant bases its proposed relief. As Mr. Bowring explains in his testimony, these inherent flaws in the proxy CT offer cap methodology undermine Reliant's proxy proposal. Although it appears that no party pointed out these defects in the New England or Midwest proceedings, they nevertheless further illustrate that Reliant has not justified its proposal.

Reliant's proposed proxy CT formula calculates the fixed cost component of a must-run unit's offer cap by a fraction, the numerator of which is the unit's fixed costs, net of revenues from sales of capacity and other services, and the denominator of which is a number of hours. Mr. Bowring explains that there are defects in both factors that undermine the validity of Reliant's formula for establishing offer caps for units that have local market power in PJM.

The numerator used in calculating the proxy formula's fixed cost component is overstated in two respects. First, it does not take account of the "insurance," or hedging, value to a generator of holding some of its units out of day-ahead markets (i.e., by submitting offer prices that are intended to exceed the market-clearing price). Bowring testimony at 30. Second, because the formula relies on average prices in capacity markets to estimate generators' revenues from those sources, it may understate the capacity revenues that the generator actually receives if it has entered into a long-term contract. Id. at 30-31. For example, until very recently, Reliant had a long-term capacity contract for some of its units at prices considerably higher than recent years' prices in PJM capacity markets. Id. Disregarding such factors inflates for some units the net fixed costs included in the numerator of the proxy CT formula's fixed cost component, yielding a higher offer cap than would apply if such units' actual revenues were used.

Mr. Bowring also identifies a defect in the denominator used in the Reliant proxy formula's fixed cost component. Reliant advocates setting the denominator equal to the greater of a unit's three-year average total run hours or 500 hours. Either of these factors, however, inherently overstates the fixed cost component of the proxy offer cap. Because of its highly efficient heat rate relative to existing units (particularly relative to 30-year-old units like Reliant's), a new CT would expect to run for considerably more than either an older unit's three-year average run hours or 500 hours each year. See Bowring testimony at 22. A new unit therefore could accept lower hourly contributions to recovery of fixed costs than the proxy formula postulates. Using unrealistically low operating hours as the denominator in calculating the proxy formula's fixed cost component artificially inflates the offer cap produced by the formula and, concomitantly, permits units with local market power to collect unnecessarily high prices during their offer-capped run hours.

Accordingly, just as it does not carry its initial Section 206 burden of proving that PJM's existing offer caps are unjust and unreasonable, Reliant also fails to establish that its proposed proxy CT offer cap would be a just and reasonable alternative to the status quo. Thus, even if Reliant had satisfied the initial prong of its burden of proof, it still would not be entitled to the relief it seeks. The Commission, therefore, should dismiss the complaint with prejudice.

VI. Response to Specific Allegations of the Complaint.

In accordance with the Commission's Rule 213(c)(2), 18 C.F.R. § 385.213(c)(2), PJM states as follows with respect to the allegations set for in Reliant's complaint:

PJM admits that it is the transmission provider under, and that it administers, the PJM Tariff. PJM further admits that the 10 units included in Reliant's complaint are, in accordance with Section 6 of Schedule 1 of the PJM Operating Agreement, subject to offer caps when they are dispatched out of economic merit order due to transmission constraints. PJM admits that the offer cap presently applicable to each of the 10 units included in Reliant's complaint is that described by Section 6.4.2(ii) of Schedule 1 of the PJM Operating Agreement, i.e., each unit's incremental operating cost, plus 10%.

PJM admits that representatives of Reliant and PJM have met and discussed issues related to PJM's offer caps for must-run generating units on various occasions and in various forums, including the LMPMWG, from approximately November 2000 through the present. PJM admits that Reliant and PJM entered into an agreement on August 3, 2001, to modify the offer caps applicable to certain of the units included in Reliant's complaint and that such agreement remained in effect until Reliant unilaterally terminated it shortly before it filed its complaint in this proceeding. PJM admits that Reliant has participated in the LMPMGW.

PJM denies all other allegations of the complaint.

CONCLUSION

The Commission should dismiss the complaint in its entirety, with prejudice. Reliant has not satisfied its initial burden under Section 206 of the Federal Power Act of proving that PJM's existing offer caps for must-run generating units are unjust and unreasonable. Morever, even if Reliant had established that PJM's existing offer caps are unjust and unreasonable (which it has not), Reliant fails to justify the alternative, proxy CT offer cap that it proposes. Therefore, Reliant is entitled to no relief.

In the alternative, should the Commission, despite the errors and defects in Reliant's complaint described in this answer, find that PJM's present offer caps for Reliant's units (i.e., those available under the LMPMWG's Interim Solution) are unjust and unreasonable, and decline to dismiss Reliant's deeply flawed proxy CT proposal, then there are genuine issues of material fact regarding the proxy CT approach, as described in Section V of this answer, that must be resolved through an evidentiary hearing before the Commission may rule on the merits of Reliant's proposed relief.

Respectfully submitted,

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Dated: April 25, 2003

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Privileged Material Redacted

Exhibit

PJM-1

EL03-116-000

Exhibit No. PJM-1

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Reliant Energy Mid-Atlantic Power Holdings, LLC,	)	
Complainant,	)	
v.	)	Docket No. EL03-116-000
PJM Interconnection, L.L.C.,	)	
Respondent.	)	

PREPARED DIRECT TESTIMONY OF
JOSEPH E. BOWRING
ON BEHALF OF PJM INTERCONNECTION, L.L.C.

APRIL 25, 2003

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Joseph E. Bowring. My business address is 955 Jefferson Avenue, Valley Forge Corporate Center, Norristown, Pennsylvania 19403.

Q. BY WHOM AND IN WHAT CAPACITY ARE YOU EMPLOYED?

A. I am employed by PJM Interconnection, L.L.C. ("PJM") as Manager of the Market Monitoring Unit.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. My testimony addresses the Complaint filed by Reliant in this proceeding. Reliant seeks an increase in the level of the offer cap applied to certain Reliant generating units that have local market power, pursuant to Schedule 1, Section 6 of the PJM Operating Agreement.

II. BACKGROUND

Q. PLEASE SUMMARIZE YOUR TESTIMONY IN THIS PROCEEDING.

A. This testimony explains the local market power issue in PJM, describes and explains the current rules governing generation offer capping for local market power in PJM, explains the meaning of reliability in PJM as it affects the application of offer capping to address local market power, reviews the experience with offer capping in PJM, explains the current Member-based process that is addressing local market power issues and responds to the specific issues raised in Reliant's complaint.

I use the term "offer cap" in this testimony rather than "cost cap" or "price cap" because the PJM Operating Agreement caps the offers of generating units that have local market power. The PJM Operating Agreement does not cap the price that such a unit can receive from the market, in that such a unit always receives the higher of its offer cap or the prevailing market price. The PJM Operating Agreement does not cap generators' variable costs, but in fact caps units' offers to sell energy, when they have local market power, at variable cost plus 10 percent, as described in the PJM Operating Agreement, Schedule 1, Section 6.4.2..

Q. PLEASE EXPLAIN WHY THERE ARE RULES GOVERNING LOCAL MARKET POWER IN PJM.

A. The rules governing the exercise of local market power were incorporated in the PJM Operating Agreement when it was first filed with the Commission in 1997. The rules on local market power were included in the Operating Agreement based on an economic analysis by Paul Joskow and Rodney Frame that was also the basis for the Commission's acceptance of market-based rates for PJM markets. These rules are, and have been, an essential part of the PJM markets from their inception on April 1, 1999.

The Joskow-Frame 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 a 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 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 sources absent the must run constraints.

The rules governing the exercise of local market power recognize that units in certain areas of the system would be in a position to extract monopoly profits, but for these rules. The owners of such units could choose to offer their output at prices exceeding competitive offers thus ensuring that the units would not be dispatched in economic merit order. If, because of a transmission constraint, PJM requires the operation of that unit, the unit would then be in a position to exercise local market power. This type of bidding behavior is easier to implement in areas where it is well known that a transmission constraint will result when certain units are not operating.

Q. PLEASE EXPLAIN THE RULES GOVERNING LOCAL MARKET POWER IN PJM AND HOW THEY ARE IMPLEMENTED.

A. The rules governing the exercise of local market power can be found in Schedule 1, Section 6 of the Operating Agreement.

Section 6 provides that a unit will be offer capped when the unit, "as a result of transmission constraints, the Office of the Interconnection determines, in the exercise of Good Utility Practice, must be run in order to maintain the reliability of service in the PJM Control Area and PJM West Region."

Units are offer capped only if they must be dispatched out of economic merit order. Units are not offer capped when their operation is required to relieve the Western, Central and Eastern reactive interface limits because it was determined that there is sufficient competition in the areas defined by these limits to effectively preclude the exercise local market power.

Section 6.4.2 of Schedule 1 provides for three offer capping options:

(i) The weighted average Locational Marginal Price at the generation bus at which energy from the capped resource was delivered during a specified number of hours during which the resource was dispatched for energy in economic merit order, the specified number of hours to be determined by the Office of the Interconnection and to be a number of hours sufficient to result in a price cap that reflects reasonably contemporaneous competitive market conditions for that unit;
(ii) The incremental operating cost of the generation resource as determined in accordance with Schedule 2 of this Agreement and the PJM Manuals, plus 10% of such costs; or
(iii) An amount determined by agreement between the Office of the Interconnection and the Market Seller.

Finally, units that are offer capped receive the higher of their offer cap or the market-established locational marginal price (LMP). Thus, if aggregate PJM market conditions cause the unconstrained system price to rise above the level of a unit's offer cap, the unit is paid that higher system LMP. The result is that units may receive significant additional energy market revenues even when they are offer capped. It is important to note that the offer capping data frequently shows the units as offer capped even when the system LMP is greater than the unit's offer cap, if the system LMP rises during a period when a unit is offer capped. Thus, when the data (used by Reliant and the MMU) show the referenced Reliant units as capped for a specific number of hours, those data may include hours during which the units were paid a market-clearing LMP greater than the units' respective offer caps.

Q. PLEASE EXPLAIN THE MEANING OF RELIABILITY IN THE CONTEXT OF THE LOCAL MARKET POWER RULES.

A. The rules governing the exercise of local market power apply when a unit is not operating as a result of economic dispatch but is required to run in order to maintain the reliability of service. This means that, in order to meet PJM's operational reliability criteria, the specific unit must be operating and providing energy to the grid.

PJM's reliability criteria require that PJM operate the system so that transmission facility loadings will be within defined limits, immediately following any single potential malfunction or failure. These potential malfunctions or failures are termed contingencies. Contingencies include the sudden and unplanned loss of a generating unit, transmission line or transformer and are, more generally, any event that would result in the loss of one or more bulk power transmission facilities.

To comply with the reliability criteria, PJM may require the operation of units as one means to control for the possible failure of facilities rather than in response to the actual failure of facilities. After PJM has exhausted the other means of controlling the system, including adjusting PARS, adjusting imports and exports, switching transmission facilities in/out of service and switching reactors in/out of service, PJM will redispatch generation units to control for a contingency.

The significance of this, with respect to the local market power rules, is that PJM may require a unit to run to control for the potential loss of a facility, if that unit is the most cost-effective means of addressing that contingency, even if that unit would not otherwise operate as the result of economic dispatch. Thus, requiring a unit to run out of economic merit order to maintain reliability does not mean that the unit is required in order to prevent the loss of load but only that it is needed in order to ensure that, if a facility were lost, that the system would continue to operate within transmission facility limits. The particular unit that PJM requires to run to solve the contingency may not be the only unit that could serve that purpose but it is the most cost-effective unit.

Q. ARE THERE ANY AREAS WITHIN THE PJM REGION WHERE THERE ARE RELIABILITY ISSUES DUE TO INADEQUATE GENERATION?

A. No. PJM regularly performs a series of tests to determine reliability within PJM and in subareas defined by transmission constraints within PJM. The results of those tests currently indicate that there are no areas within PJM where there are reliability issues due to inadequate generation.

Q. PLEASE EXPLAIN THE MEANING OF SCARCITY IN THE CONTEXT OF LOCAL MARKET POWER.

A. It is frequently assumed that scarcity exists whenever a unit is offer capped under the local market power rules. That is not correct. There can be, and frequently is, more than enough generation in an area to serve local load when units are offer capped.

For example, consider an area with 500 MW of load and 1,000 MW of generation, all owned by a single company. If the market clearing price is $40 per MWh and transmission facilities into the area limit imports to 400 MWh, then units in the area will be required to run and they will be offer capped if their price offers are in excess of $40 per MWh. These units would have local market power because 100 MW is required to run to meet the load and all generation is owned by a single company. In the absence of rules governing the exercise of local market power, the units could charge any price up to $1,000 per MWh (the overall PJM offer cap) and would be paid that price. To prevent such an exercise of local market power in such a situation, the units would be offer capped and paid the higher of the market price or their offer capped rate.

In this situation, there is clearly no scarcity of generation in the relevant area. There is 1,000 MW of generation and only 100 MW of load that cannot be met by imports. Accordingly, there is no need for scarcity pricing in this situation.

To extend the example, if some of the generation in the area has marginal costs of $30 per MWh yet submits price offers of $80 per MWh, the reason that the generation will not run is because it has offered its energy at uneconomic levels, i.e. it has withheld the energy economically. If the same units had offered their energy at marginal cost, they would have been dispatched in merit order and received the market clearing price of $40 per MWh. In such a case, no units would be offer capped.

It would clearly be inappropriate, in this case, to implement a high offer cap based on scarcity or the need to provide an incentive for entry. There is no reason to provide an artificial signal for entry or to pay the existing units in excess of market prices. Generation adequacy is not the issue in this example. This example represents the actual facts in many cases of offer capping in PJM, including most cases of offer capping for the Reliant units at issue in this proceeding.

Q. CAN GENERATION SCARCITY BE AN ISSUE IN CASES OF LOCAL MARKET POWER?

A. Yes. While generation scarcity does not always exist in cases of local market power, it can exist at times. Local scarcity exists when there is inadequate generation and transmission import capability to serve the load in an area. In the example just presented, there would be local scarcity if the local generation were 100 MW or less. While there are no situations in PJM where there are reliability issues and thus no situations where local scarcity is expected, scarcity could arise, for example, if load were greater than expected or if a transmission or generation facility were lost unexpectedly.

Q. DOES OFFER CAPPING GENERALLY CAUSE FINANCIAL HARM TO UNITS THAT ARE CAPPED?

A. No. Units that are offer capped receive the higher of the market price or their capped offer. When a unit receives the market price, it may receive a margin above its marginal costs plus ten percent, depending on market conditions. If a unit receives its cost-based offer, it receives full compensation for marginal costs plus a 10 percent margin. In effect, units that are offer capped are running during hours when they would not otherwise have run based on economic dispatch and are assured of a margin over incremental costs for operating during each of those additional hours. Units that have a high proportion of offer capped run hours (like the referenced Reliant units) would have run very little if they were not required to run by PJM and offer capped. The result is that offer capped units are generally better off than comparable units for which hours of operation are entirely a function of economic dispatch. I present an example of this below for specific Reliant units.

III. NEGOTIATIONS WITH RELIANT

Q. PLEASE DESCRIBE PJM'S NEGOTIATIONS WITH RELIANT CONCERNING OFFER CAPPING FOR LOCAL MARKET POWER.

A. Reliant approached PJM to discuss the status of certain offer capped units in November 2000. The discussions were general and served to communicate

Reliant's general concerns with the rules for offer capping to address local market power. At the conclusion of the discussions, I requested that Reliant indicate exactly which of its units it was concerned about and that Reliant provide unit specific data to support any claims that the units were not being adequately compensated under the rules for local market power. Reliant never provided any data to support their claims about unit specific financial impacts due to offer capping for local market power, although some data was provided at our final negotiation meeting.

The MMU also engaged in discussions with Reliant regarding an adder to the marginal cost plus ten percent offer caps for specific Reliant units where run hours are constrained by conditions in environmental (air quality) permits. Such environmentally constrained units can operate for only a limited number of hours each year. The rationale for the proposed cost adder was that when PJM required such units to operate for hours during the non-summer period, the units were denied the opportunity to operate for the same number of hours during the summer when prices are generally expected to be higher.

These discussions culminated in August 2001 in an agreement between the MMU and Reliant under which a defined level of opportunity cost was added to the costs for each such unit. The opportunity cost adder was based on an option valuation model proposed by Reliant and agreed to, after review and some mutually acceptable modifications, by the MMU.

As it turned out, the market derived calculations of the option value of the affected units' non-summer operating hours was quite modest. Although Reliant indicated to me that it had expected the adder to be larger than it was in fact, Reliant never challenged the results. Contrary to Reliant's implication in its Complaint, the MMU never indicated that we would develop a model that would support larger opportunity cost adders for Reliant's units. Reliant unilaterally, and without prior warning, cancelled this 2001 agreement several days prior to filing the present complaint with the Commission.

The MMU has had more recent discussions with Reliant about options for modifying PJM's offer caps. Reliant approached PJM in a meeting on February 11, 2003 and proposed that PJM accept a modified version of the proxy method. PJM indicated that the proxy method is not a reasonable approach to mitigating the local market power of must run units in PJM.

The MMU also continued informal discussions with Reliant in the context of the PJM's Local Market Power Mitigation Working Group (LMPMWG) meetings. The MMU also met separately with Reliant to try to develop an approach to local market power. Ultimately, Reliant was not willing to accept the approach adopted by the LMPMWG (Interim Solution). PJM's MMU explicitly offered to modify Reliant's offer caps on the same terms included in the Interim Solution adopted by the LMPMWG, but Reliant declined and instead filed its Complaint.

Q. DO YOU HAVE ANY INFORMATION ON WHETHER RELIANT CONTINUES TO MAINTAIN ITS OFFER CAPPED UNITS IN ACCORDANCE WITH GOOD UTILITY PRACTICE?

A. Yes. A representative of Reliant has indicated to me on several occasions that Reliant is not maintaining its offer capped units because Reliant is not satisfied with the offer capping rules for mitigating local market power. Shortly thereafter several Reliant units, including one of the offer capped units named in Reliant's Complaint, tripped off line due to a ground fault **REDACTED** sent two engineers to the unit to investigate but they could not determine whether there was inadequate maintenance or whether inadequate maintenance contributed to the problem at the unit. The MMU intends to require Reliant to show that it is maintaining its units consistent with good utility practice. This raises a potential issue of physical withholding.

IV. <u>LOCAL MARKET POWER MITIGATION WORKING GROUP</u>

Q. PLEASE EXPLAIN THE HISTORY AND ACTIVITIES OF THE LOCAL MARKET POWER MITIGATION WORKING GROUP.

A. I formed the Local Market Power Mitigation Working Group (LMPMWG) in September 2002 to address the ways in which local market power is limited in PJM as the result of concerns expressed by a number of generators and load representatives in different venues. The first LMPMWG meeting was held on September 26, 2002 and the group has met approximately biweekly from September through the present. My purpose in forming the group was to create a forum for a focused discussion of the issues surrounding the limitation of local market power via offer capping among stakeholders representing all perspectives in the marketplace. Generators, industrial customers, small customers, public utility commissions and transmission owners were all represented. There were generally about 50 attendees at the LMPMWG meetings. Outside speakers were invited to make presentations on various aspects of the issues. Issues papers and presentations were exchanged and discussed.

As the LMPMWG's discussion evolved, it became clear that there would not be adequate time prior to the 2003 summer season to create a long term solution that participants believed would adequately address the complex issues associated with local market power. The group supported the MMU's position to put an interim solution in place for the summer of 2003 and to commit to completing, with the concurrence of the MMU, a long term solution by the end of 2003. The PJM MMU indicated its commitment to the members to develop a long term solution prior to the end of 2003.

Q. DID THE LOCAL MARKET POWER MITIGATION WORKING GROUP SUPPORT AN INTERIM SOLUTION FOR THE SUMMER OF 2003?

A. Yes. The LMPMWG supported an Interim Solution at its meeting of April 14, 2003. That agreement was supported by a large majority in the Energy Market Committee meeting on April 16, 2003. The Interim Solution will be in place only until implementation of the long term solution that will be developed by the end of 2003.

Q. PLEASE DESCRIBE THE LOCAL MARKET POWER MITIGATION WORKING GROUP'S INTERIM SOLUTION.

A. The LMPMWG's Interim Solution has several key elements. The Interim Solution identifies two thresholds for increased generator offer caps: units that were offer capped more than 80% of their run hours and that operated for more than 200 total hours in 2002 and units that were offer capped more than 50% but less than 80% of their run hours and that operated for more than 200 total hours in 2002. The Interim Solution also provides for the inclusion of units operating less than 200 hours in 2002; the adder will be adjusted to reflect 200 hours of operation. The Interim Solution provides an adder of $40 per MWh to marginal costs for the 17 units meeting the first threshold and an adder of $20 per MWh to marginal costs for the additional 11 units meeting the second threshold.

The Interim Solution provides that the specified amounts will be added to the marginal costs of the defined units to replace the current 10 percent adder, that these bids will affect dispatch decisions, that these bids will be used by PJM's LMP algorithms and that therefore these bids will be reflected in LMPs. The Interim Solution also provides that any unit receiving the specified adder must agree that the unit will be maintained consistent with good utility practice.

Finally, the Interim Solution commits the LMPMWG to developing a long term solution by November 30, 2003. This solution would be filed with the Commission. If the LMPMWG does not reach agreement by that date, that is acceptable to the MMU, the MMU will file a proposed solution with the Commission prior to the end of 2003.

Q. PLEASE EXPLAIN HOW THE INTERIM SOLUTION WILL BE IMPLEMENTED.

A. The PJM MMU will implement the Interim Solution consistent with the PJM Operating Agreement, Schedule 1, Section 6.4.2 (iii) which permits offer caps in "An amount determined by agreement between the Office of the Interconnection and the Market Seller." The MMU sent a letter to PJM's Members on April 22, 2003 advising them that it is willing to negotiate an agreement for revised offer caps as provided by the Interim Solution with the owner of any generating unit that meets the agreed upon thresholds and to implement such terms for specific units upon the signing of a specific agreement pursuant to Schedule 1, Section 6.4.2 (iii) of the Operating Agreement.

V. <u>THE RELIANT UNITS</u>

Q. WHY ARE THE REFERENCED RELIANT UNITS OFFER CAPPED?

A. The Reliant units referenced in its Complaint are offer capped because they have local market power. Units have local market power when PJM requires them to operate, and they are not otherwise dispatched in economic merit order, to control for a contingency on the PJM system. Reliant units are frequently offer capped because their generation offers were too high to result in economic dispatch. That is precisely the intent of the local market power mitigation rules. But for the offer caps imposed by Section 6.4.2 of the Operating Agreement, Reliant would be able to exercise the local market power of these units to obtain monopoly profits during such hours.

It is important to recognize that the number of hours a unit is offer capped is not a measure of the unit's contribution to system reliability or an indication that a unit is in a chronically transmission constrained area. A significant determinant of the number of hours a unit is offer capped is the relationship between a unit's price offers and its actual costs of operation. The Reliant units would have been offer capped for fewer hours and operated for substantially more hours under economic dispatch had they offered the units to the system at competitive prices.

The bidding behavior of units also affects the proportion of run hours that are offer capped. If a unit regularly offers its energy at above market rates with the result that it is offer capped whenever local generation is needed, the data will show a high proportion of run hours offer capped. This is the result of bidding behavior and does not necessarily indicate anything about the adequacy of local generation or need for the particular unit.

One of the concerns in designing a method for mitigating local market power is the potential creation of incentives to be cost capped more frequently. If a method of offer capping were adopted that compensates units significantly better than comparable units subject to economic dispatch, an incentive is created to be offer capped. The Reliant proxy method is such a method. Some units have the ability to directly affect the number of hours that they are offer capped via their bidding strategy. There are other units on the PJM system that could offer their units so as to produce a large number of offer capped hours.

Q. PLEASE DESCRIBE THE TEN REFERENCED RELIANT UNITS.

A. The ten Reliant units, referenced in the Reliant Complaint, are simple cycle combustion turbines with a nominal capacity of about 20 MW each. Total capacity of the ten units is about 198 MW. The units are General Electric Frame 5N industrial combustion turbines. Five of the units were installed and became operational in 1971 while the remaining five units were installed and became operational in 1972. The average heat rate of the units is 15,138 BTU/KWh while the unit heat rates range from 13,703 BTU/KWh to 15,464 BTU/KWh. Four of the units use only No. 2 fuel oil, one unit uses natural gas only while the remaining five units are capable of using either oil or natural gas. See Schedule JEB-1 for complete, unit-specific details.

Nine of the ten referenced Reliant units are in Pennsylvania, in an area of the Metropolitan Edison (Met Ed) zone referred to as West Met Ed. The remaining unit, Blossburg, is on the 69KV system near East Towanda, in the Penelec zone, also in Pennsylvania.

Q. WHY WERE THE REFERENCED RELIANT UNITS OFFER CAPPED IN 2001 AND IN 2002?

A. Reliant units were offer capped for more hours in 2002 than in 2001 but for a approximately the same proportion of total run hours in 2002 as in 2001. In both

2001 and 2002, the Reliant units in the Western Metropolitan Edison area were cost capped in significant part because of temporary transmission issues. These issues were more significant and longer lasting in 2002. These transmission issues have been addressed via upgrades in the area and new transmission investments continue.

In 2001, the Hunterstown 230/115 kV transformer was out of service for two weeks in August due to equipment failure.

In 2002, in the Western Metropolitan Edison area, the Hunterstown 500/230 KV transformer was destroyed in a fire on August 2. This transformer was a key source of import capability into the area where 9 of the 10 referenced units are located. The destroyed 500/230 KV Hunterstown transformer is being replaced with an in-service date in July 2003. First Energy also replaced the Hunterstown 230/115 kV transformer with a higher rated bank, completing the work on January 2, 2003. In addition, the Transmission Owner, First Energy, reconductored a local 115 kV bus, completing the work in May 2002. First Energy also upgraded the river crossing and drop legs of the Middletown Junction-Collins-Cly-Newberry (975) 115 kV circuit, completing the work in June 2002. All of these events resulted in a short term reduction in import capability into the area. As a direct result of the reduced import capability associated with these events and the interaction between market prices and the offers of the Reliant units, the Reliant units in the area were called to operate out of merit order more often in 2002 than in 2001.

Additional transmission upgrades are in progress that will further reduce the need to offer cap Reliant generation in this area. These projects include the installation of 18 MVAR of capacitance at Round Top 115 kV, with an expected completion date in June 2003, the construction of the Otter Creek 230 kV station, with an expected completion date in June 2004 and the upgrading of the Middletown Junction-Zions View 115 kV line, with an expected completion date in June 2005.

Q. WILL THE REFERENCED RELIANT UNITS BE OFFER CAPPED LESS IN THE FUTURE?

A. Yes. As the result of transmission upgrades in both areas at issue in this matter, it is expected that the referenced Reliant units will be offer capped less frequently. As noted, in the West Met Ed area, key upgrades are being made and an existing 230/115 KV transformer, fed by the Hunterstown transformer, has been upgraded to a higher rating. The result of the upgrades to the system is expected to be a significant increase in import capability to the area and a reduction in the levels of offer capping.

In addition, the 10th unit, Blossburg CT, will be favorably affected by an ongoing transmission upgrade. A second 230/115 KV transformer is being installed at North Meshoppen. The installation of this transformer is expected to alleviate some of the transmission issues in the Towanda area and reduce the need for running Blossburg out of merit order.

VI. FINANCIAL PERFORMANCE OF THE RELIANT UNITS

Q. PLEASE EXPLAIN HOW YOU EVALUATED THE FINANCIAL PERFORMANCE OF THE REFERENCED RELIANT UNITS IN 2002?

A. The MMU evaluated the financial results for the Reliant units in several ways including the results based on our estimate of unit costs and actual revenues, the results based on our estimate of unit costs and dispatch based on competitive offers, the results based on the Reliant proxy method costs and actual revenues and the results based on the Reliant proxy method costs and dispatch based on competitive proxy offers.

The basic components of total unit costs, regardless of method, include:

- Fuel costs per MWh that are the result of the direct cost of fuel and the heat rate of the unit
- Long run variable O&M costs based on the fact that the start up and operation of CTs produced expected wear and tear to the components of a unit that create a causal relationship between hours of operation and numbers of starts and the costs of inspections and overhauls.
- "To go" costs that include primarily labor, insurance and property taxes
- Fixed costs that include debt costs, rate of return on equity, taxes and depreciation and are a function both of the level of the investment and assumptions about key financial parameters

The basic components of unit revenues, regardless of method, include:

- Energy market revenues that are the direct result of the way in which the unit is dispatched. Energy market revenues for these units frequently exceeds the cost plus ten percent level
- Capacity market revenues
- Ancillary market revenues
- Black start revenues
- Operating reserve revenues

Q. WHAT WAS THE FINANCIAL PERFORMANCE OF THE REFERENCED RELIANT UNITS IN 2002 BASED ON ESTIMATED ACTUAL COSTS?

A. We first applied MMU costs estimates for the Reliant units, including fuel costs based on an index plus a basis adjustment, long run variable O&M costs based on manufacturers' data and information provided by Reliant, "to go" costs based on industry information obtained from independent contractors that are in the business of providing turnkey O&M services and fixed costs based on the last reported rate base values for the units and Reliant's proxy method financial assumptions about rate of return, depreciation and so on. On the revenue side, we used actual revenues from all sources and a full years worth of black start revenues to reflect expected results.

REDACTED

REDACTED

Q. WHAT WAS THE FINANCIAL PERFORMANCE OF THE REFERENCED RELIANT UNITS IN 2002 BASED ON RELIANT'S PROXY METHOD?

A. We evaluated the financial performance of the Reliant units based on Reliant's proxy method. The key elements of the Reliant proxy costs are fuel costs as a function of the proxy heat rate, the long run variable O&M set at $3.00 per MWh and "to go" and fixed costs per the proxy assumptions. It is important to note that the use of actual 2002 revenues for these units is not consistent with the basic proxy method logic. The reason is that the proxy heat rate is substantially lower than the actual unit heat rates, the fuel cost of the proxy unit is lower and therefore the proxy unit will be dispatched more often for a given level of prices and will earn more revenues.

REDACTED

REDACTED

Q. WHAT WAS THE FINANCIAL PERFORMANCE OF THE REFERENCED RELIANT UNITS IN 2002 BASED ON RELIANT'S PROXY METHOD INCLUDING DISPATCH BASED ON THE PROXY HEAT RATE?

A. We evaluated the financial performance of the Reliant units based on Reliant's proxy method, but included the revenues that result from dispatch using the proxy heat rate of 10,500 BTU/KWh rather than the actual unit heat rates that average around 15,100 BTU/KWh.

REDACTED

REDACTED

Q. WHAT HAS BEEN THE FINANCIAL IMPACT ON THE REFERENCED RELIANT UNITS OF OFFER CAPPING?

A. The Reliant units have received revenues from a variety of market sources that

REDACTED

Q. HOW DID THE FINANCIAL RESULTS OF THE REFERENCED RELIANT UNITS COMPARE TO THAT OF OTHER COMPARABLE UNITS OWNED BY RELIANT IN PJM IN 2002?

A. The MMU examined the performance of four of Reliant's Glen Gardner Combustion Turbines. These units were selected because they are the same technology and vintage as the units referenced in Reliant's complaint and because these units were offer capped for only about 20 percent of their run hours.

REDACTED

REDACTED

The detailed results are presented in the attached Schedule JEB-4. The same comparative results hold, regardless of the method of analysis.

Q. HOW DID THE FINANCIAL RESULTS OF THE REFERENCED RELIANT UNITS COMPARE TO THAT OF OTHER COMPARABLE UNITS IN PJM IN 2002?

A. As demonstrated in the PJM Interconnection State of the Market Report Net Revenue analysis, market conditions in 2002 resulted in lower net revenues for units across the range of operating costs than in prior years. In particular, a new combustion turbine (CT) earned less in 2002 than in prior years as the result of market conditions and would not have earned enough to cover all its fixed costs including a rate of return.

REDACTED

The Net Revenue calculations in the State of the Market Report showed that a new CT would have earned between $43,431 and $50,557 per MW in 2002.(PJM Interconnection State of the Market Report 2002, page 34.)

REDACTED

REDACTED

The overall Net Revenue results were quite different in 2002 than in prior years. The PJM Interconnection State of the Market Report includes the Net Revenue analysis each year. In 1999 net revenues were enough to more than cover the full costs of a new CT, in 2000 net revenues were approximately equal to the full cost of a new CT and in 2001 net revenues were enough to more than cover the full costs of a new CT in PJM.

Prices follow cycles in markets and 2002 was a relatively low price year in both the energy and capacity markets. Reliant's net revenues reflected that fact. It is important not to confuse the aggregate market impacts with the impacts of running units at their offer caps. It is clear that the results cited by Reliant are the direct result of aggregate PJM market conditions and not the result of PJM capping Reliant's offers.

Q. WHAT WERE THE PRIMARY DETERMINANTS OF THE FINANCIAL PERFORMANCE OF THE REFERENCED RELIANT UNITS IN 2002?

A. The primary determinants of the financial performance of the referenced Reliant units in 2002 were market conditions in the energy markets and in the capacity markets. As reported in the PJM Interconnection State of the Market Report, load weighted energy prices declined by 13.8 percent in 2002 over 2001 while capacity market prices declined by 65 percent.

The MMU has calculated financial results for the 10 referenced units under conditions equivalent to energy markets in 2001 and the three year average capacity market prices. The results show that the performance of the Reliant units is extremely sensitive to overall energy and capacity market conditions.

REDACTED

In other words, even using the Reliant proxy fixed costs, the 10 Reliant units would have more than covered their total costs under market conditions that are reasonably reflective of historical conditions in PJM if the units had offered their energy to PJM at cost plus the $3/MWh proxy variable O&M in every hour.

These calculations demonstrate that the performance of Reliant's units is extremely sensitive to market conditions, as one would expect for Combustion Turbines. The real issue in this matter is not offer capping but the fact that Reliant's CTs, like those of other generation owners, suffered low revenues in 2002 as the result of aggregate market conditions.

Reliant's filing can reasonably be seen as an effort to insulate the identified units from the risks associated with markets rather than as about real flaws in the system of market power mitigation.

RELIANT'S PROXY METHOD

Q. RELIANT HAS REQUESTED THAT A PROXY METHOD BE USED TO DETERMINE PAYMENTS WHEN A UNIT HAS LOCAL MARKET POWER. PLEASE EXPLAIN RELIANT'S PROXY METHOD.

A. The proxy method is a method for determining the payments that would be made to a unit that possesses local market power due to inadequate local competition.

The proxy method is designed to determine the total revenues required by a newly constructed CT in order to cover its variable costs and its fixed costs including the return on and of capital. The proxy method calculates the variable costs, including fuel costs, based on the heat rate of a new unit as specified by the manufacturer as well as the fixed costs based on the costs of the turbine and ancillary equipment and a set of financial assumptions including capital structure, rate of return on equity, debt costs, depreciation life, tax depreciation method and project life. The proxy method is, in effect, a generalized RMR (Reliability Must Run) approach.

The Reliant proxy method is designed to virtually ensure that all units with local market power recover 100% of the revenue requirement associated with a new unit. (The ISO-NE proxy method is not designed to ensure unit specific cost recovery and is designed based on area-wide congested hours rather than unit-specific offer capped hours.) This revenue requirement bears no explicit relationship to the actual revenue requirement of actual, existing units and can be expected to exceed the revenue requirement of the actual, installed CTs at issue in this complaint. The proxy method, applied to existing units, is equivalent logically to the application of a rate base – rate of return regulatory method using replacement cost rather than book cost.

Q. IS THE RELIANT PROXY METHOD A "MARKET-BASED" METHOD OF ADDRESSING LOCAL MARKET POWER?

A. No. The Reliant proxy method is a regulatory solution that would insulate affected units from most market-related risks. It is significantly less market-based than other means of addressing local market power. The Reliant proxy method is designed to virtually ensure the recovery of all the costs of a brand new CT and thus, in general, provide for recovery in excess of the actual costs of existing CTs. The fact that unit costs are based on a small number of actual observed CT purchases does not make the proxy method a market-based method.

Q. WHY DOES THE PROXY METHOD USE THE COSTS OF A NEW UNIT TO VALUE OLD UNITS?

A. The concept is that the use of a proxy method would provide an incentive to new units to enter the market by providing a level of cost recovery based on the costs of a new unit. It is unclear whether proponents of the proxy method believe that the new unit would be offer capped upon entry. If new units are offer capped and guaranteed cost recovery, it is inappropriate to use a proxy calculation that assumes a unit facing competitive risks including higher levels of equity in the capital structure, higher costs of capital and a short project life.

Q. DOES THE RELIANT PROXY METHOD IGNORE SPECIFIC SOURCES OF VALUE ASSOCIATED WITH UNITS?

A. Yes. The proxy method ignores the option value of holding CTs in a portfolio of generation assets. It is a common bidding strategy for a generator to offer some of its units into the day ahead market at a price higher than the price at which it expects the market to clear. The rationale for this approach is that the generation owner wants to hold units as insurance in the event that one of its units, that is financially committed in the day ahead market, trips in real time, thus requiring the owner to supply the energy from another source. Financial risk to the owner arises if such an unexpected outage were to occur when the spot market energy price in real time is high relative to the day-ahead price and the generation owner is required to provide the lost energy by purchasing from the real time spot market. Units held out of the day ahead market via high offers serve as insurance in such cases. The units serve as a hedge against high real time prices because the units can generate energy at a price determined by the cost of fuel and the heat rate of the unit. This limits the exposure of the owner in real time. This hedge function has value and would have to be paid for if purchased in the market. This value is ignored in the Reliant proxy approach and thus, even on its own terms, the Reliant proxy method overstates the required revenues.

The proxy approach also ignores bilateral contracts. If, for example, a generation owner has a long term bilateral arrangement to sell capacity and/or energy for a price that exceeds the current market price of capacity and/or energy, then the proxy method would over compensate the owner. In fact Reliant's filing indicates that they had such a bilateral capacity contract in prior years for at least some of the referenced units.

Q. ARE THERE OTHER ISSUES WITH RELIANT'S PROPOSED PROXY METHOD?

A. Yes. Reliant's proposed application of the proxy method is seriously flawed. For example, Reliant's proposed application of the proxy method uses the higher of recent actual run hours or 500 hours as the denominator of proxy costs in order to calculate the per MWh offer cap. Actual run hours are clearly a mismatch with the expected run hours of a proxy unit with its associated relatively low heat rate.

The heat rates of the Reliant units are substantially higher than the proxy heat rate, meaning that the variable costs or dispatch rates of the Reliant units would be substantially higher, meaning in turn that their expected run hours would be less than the run hours of a proxy unit. Thus, the annual run hours that Reliant used to calculate its proxy-based adder are unjustifiably low. Reliant's use of the lower actual run hours inappropriately inflates its calculated offer cap. The 500 hours is apparently intended to be based in some way on the ISO-NE proxy method where the denominator of proxy costs is constrained to be between 500 and 2,000 hours.

Reliant's proposed method relies upon CT costs derived from a study done in New England using data from units purchased in 2001 when the market for gas-fired turbines was very tight. Demand for turbines is lower today, indicating that the fixed equipment costs on which Reliant bases its proxy calculations, are overstated. Given changed conditions in the capital markets, the costs of debt and equity are also overstated in Reliant's calculations. In addition, the proxy method relies upon key financial assumptions premised on the unit being built and financed as a competitive, merchant unit without the protections afforded by the application of a proxy method. Thus, there is a relatively large amount of equity in Reliant's proxy capital structure and Reliant's assumed project life, over which all costs must be recovered, is relatively short. In fact, the application of the proxy method would effectively make these units regulated units and the financial assumptions should reflect the associated reduced level of risk.

Reliant's version of the proxy method, regardless of the broader issue with the proxy method, is fatally flawed and should not be implemented in PJM.

Q. RELIANT EMPHASIZES THAT THE COMMISSION HAS ACCEPTED THE PROXY METHOD FOR ISO NEW ENGLAND (ISO-NE) AND THE MIDWEST INDEPENDENT SYSTEM OPERATOR (MISO). DOES THIS ESTABLISH THAT THE PROXY METHOD IS APPROPRIATE FOR PJM?

A. No. There are significant differences between ISO-NE and PJM and between MISO and PJM. ISO-NE has significant, structural market issues that result from inadequate transmission infrastructure, that do not exist in PJM. Approximately one third of the total load in ISO-NE is in areas where transmission is chronically constrained, areas that ISO-NE terms Designated Congestion Areas (DCA). PJM has no areas that are equivalent to DCAs. ISO-NE has defined the threshold area congestion hours at 2,000. The West Med Ed area had 532 hours of congestion in 2001 and 653 hours of congestion in 2002, clearly well short of the ISO-NE definition of an area requiring application of the proxy method. ISO-NE has also signed numerous RMR contracts directly with generation owners because market revenues have not been adequate to ensure their viability. This has not been the case in the PJM markets where market revenues have been more than adequate, as measured by the Net Revenue Test. In addition, ISO-NE has a capacity market with very different features and functionality than the PJM capacity marketes. ISO-NE has indicated in its market rules that it would reconsider its proxy method when, for example, its capacity market is redesigned to include the deliverability features of the PJM capacity markets. The ISO-NE is explicitly using the proxy method as a way to make a transition to a more complete capacity market construct.

MISO does not at present have any energy markets whatsoever, so it is difficult to compare the functioning of the PJM markets with MISO markets. However, the conceptual design of MISO markets on which the proposed proxy method is presumably based, does not include a capacity market. The PJM market does have capacity markets that have been the source of significant net revenues in every year of PJM's competitive markets.

Q. HOW DO THE RESULTS OF THE APPLICATION OF ISO-NE'S PROXY METHOD COMPARE TO RELIANT'S PROPOSED PROXY METHOD?

A. The actual calculated adders in the ISO-NE market based on the application of the ISO-NE method are about $35 per MWh. This is dramatically less than Reliant's proposed adders **REDACTED** Equally significant, the actual proxy-unit based adders are less than agreed to by the LMPMWG and currently available to any generator in PJM meeting the criteria specified by the LMPMWG.

Q. PLEASE EXPLAIN THE "TO GO" METHOD ADOPTED AS THE INTERIM SOLUTION BY THE LOCAL MARKET POWER MITIGATION WORKING GROUP.

A. The "to go" method provides an assurance to existing units that they will recover the annual out of pocket expenditures required to operate their units ("to go" costs) and leaves recovery of the balance of unit costs to market forces. Revenues from the energy markets, from the capacity markets, from ancillary services markets, from black start and from operating reserves are market sources of revenue that contribute to the recovery of costs by all units, including units offer capped for reasons of local market power.

The MMU recognizes that the "to go" approach does not include an explicit method for scarcity pricing under scarcity conditions in local areas. This is one of the matters that will be addressed as we work to develop a long term solution for mitigating local market power.

Q. DOES THE PROXY METHOD PROVIDE APPROPRIATE SCARCITY PRICING?

A. No. The proxy method is designed to base offer caps on proxy units' full revenue requirements recovery and has nothing to do with scarcity pricing. The proxy method not only overstates the appropriate price for units with local market power but may also understate the appropriate price under actual scarcity conditions. To understand the appropriate method of addressing local market power, it is essential to understand the simple fact that requiring a unit to operate for reliability does not mean that scarcity conditions exist.

In fact, it is much more likely to be the case that generation is required for reliability due to transmission constraints but there is no scarcity. That is the generally the case for the referenced Reliant units. Reliant's units are in areas where the available generation in the constrained area generally exceeds load in that area. Nonetheless, when local load exceeds the transmission import capability, some of the generation in that area must run for reliability. There is no scarcity of generation, however. There is only the ability to exercise local market power by generation located in an area constrained by transmission.

In such cases, it would be inappropriate to implement the proxy method to provide scarcity pricing as an incentive for more generation entry. That would be exactly the wrong price signal.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Privileged Material Redacted

Schedule JEB-1

Privileged Material Redacted
(One Page)

Privileged Material Redacted

Schedule JEB-3

Privileged Material Redacted
(One Page)

Privileged Material Redacted

Schedule JEB-4

Privileged Material Redacted
(One Page)

State of Pennsylvania)
) SS
County of Montgomery)

AFFIDAVIT OF JOSEPH E. BOWRING

Joseph E. Bowring, being first duly sworn, deposes and says that he has read the foregoing "Prepared Direct Testimony of Joseph E. Bowring on behalf of PJM Interconnection, L.L.C.," in FERC Docket No. EL03-116-000, that he is familiar with the contents thereof, and that the material set forth therein are true and correct to the best of his knowledge, information and belief.

s/s Joseph E Bowring
Joseph E. Bowring

Subscribed and sworn to before me this 24th day of April, 2003.

s/s Renee L Doganieri
Notary Public

My Commission expires: August 25, 2003

Notarial Seal
Renee L. Doganieri, Notary Public
Lower Providence Twp., Montgomery County
My Commission Expires Aug. 25, 2003
Member, Pennsylvania Association of Notaries

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Exhibit

PJM-2

EL03-116-000

PJM

Market Monitoring Unit

April 22, 2003

Members Committee
Energy Market Committee
Local Market Power Mitigation Working Group

Dear Members:

RE: LMPMWG INTERIM SOLUTION IMPLEMENTATION

Based on recent votes of the Local Market Power Mitigation Working Group and the Energy Market Committee supporting an Interim Solution for offer capping for 2003, the PJM Market Monitoring Unit will agree to negotiate offer capping agreements with generation owners consistent with Operating Agreement, Schedule 1, Section 6.4.2 (iii), consistent with the following terms.

1. For any unit that:
   a. Was offer capped in 2002 more than 80% of its operating hours;
   b. Was offer capped in 2002 more than 50% and less than 80% of its operating hours;
   c. Operated more than 200 hours in 2002;
   d. Was required for reliability; and
   e. Did not cover its fixed costs with other revenues,
2. The Market Monitoring Unit will negotiate modified offer caps to include:
   a. An adder of $40 per MWh for any unit that was offer capped more than 80% of its run hours during 2002 and operated for more than 200 hours in 2002; or
   b. An adder of $20 per MWh for any unit that was offer capped more than 50% of its run hours and less than 80% of its run hours during 2002 and operated for more than 200 hours in 2002; or
   c. An adder based on 200 hours for any units that was offer capped more than 50% of its run hours and ran less than 200 hours; and
   d. An agreement that the owner of the unit will maintain the unit consistent with good utility practice.

These agreements will implement the Interim Solution for 2003 and will remain in effect, subject to review by the Market Monitoring Unit of experience under such arrangements, until implementation of a permanent local market power mitigation solution, to be developed by the Working Group or, should the group fail to produce an agreement, to be filed with FERC by the Market Monitoring Unit, by the end of the year.

Any interested generator should contact me to set up a schedule for negotiating a contract consistent with the terms outlined above.

Please let me know if you have any questions. You can reach me at 610-666-4536 or at bowrij@pjm.com.

Sincerely,

Joseph E. Bowring
Manager

JEB/vlf
DMS #208958v1

Exhibit

PJM-3

EL03-116-000

Platts Energy Business & Technology October, 2002

platts ENERGY BUSINESS & TECHNOLOGY

Platts Energy Business & Technology

October, 2002

SECTION: GENERATION; Vol. 4, No. 6; Pg. 35

LENGTH: 1128 words

HEADLINE: How bad is business? Terrible, some new numbers confirm

BYLINE: BY BILL HORTON; Bill Horton is a research analyst with Platts Research & Consulting, a unit of The McGraw-Hill Companies, and can be reached at bill_horton@platts.com.

HIGHLIGHT:
Battered by slumping wholesale prices, slashed debt ratings, liquidity problems, and major hurdles to new financing, power generators are tabling and canceling projects at a record pace

BODY:
As the latest boom cycle in power plant construction wanes, the winter months could usher in an acceleration of announcements as developers reassess when to attack markets. Reserve margins nationally have risen back to historical average levels, making opportunities more difficult to pinpoint. A result is that many companies are deferring their plans. This may have a backlash in a dramatic slowing of new operating capacity coming on line, further complicating the supply picture beyond 2004.

From January 2002 through July 2002, U.S. power generators' tabled capacity jumped 68% year to date over 2001 and canceled capacity increased 30% year to date over 2001. Nearly 90,000 MW were tabled and 87,000 MW were canceled (Fig. 1) between January 2000 and July 2002, according to an analysis using data from Platts' NEWGen power plant data base.

Compare those figures with what happened in 2001 and 2000. During 2001, 27,998 MW were tabled and 32,408 MW were canceled. During 2000, 17,969 MW were tabled and 12,049 MW canceled. The trend manifests at Atlanta-based General Electric Co.'s Power Systems division, which is currently forecasting an 80% decline in U.S. gas-fired **turbine** order and shipment volume, according to CEO John Rice. GE Power Systems recently decided to layoff 2,500 of its employees.

Declines are not only occurring in the U.S. Gas **turbine** deliveries worldwide are also affected, according to Siemens USA (Orlando, Fla.) executive Melanie Forbrick. Siemens' global gas **turbine** deliveries are forecast to drop 50% over the fiscal periods covered by

2002 and 2003. Specifically, Forbrick says Siemens anticipates **turbine** shipment reductions of 1% in 2002, 32% in 2003, and 57% in 2004. The numbers are reductions from last year's anticipated schedule. One bright note says Forbrick, is that some orders are being deferred rather than canceled outright.

Blame competition Power prices are not high enough to generate a return on capital and fixed costs -- in some regions, spark spreads are negative -- and excess capacity forecasts for the next several years all tend to put a damper on company construction plans, explains Peter Rigby, a director of Standard & Poor's, a unit of The McGraw-Hill Companies. Weaker credit ratings and falling equity prices are creating an atmosphere that discourages banks from lending for new projects. "Power contracts can mitigate risk; however, few load-serving entities want to commit to long-term obligations right now," Rigby says.

Changes in the number of projects tabled and canceled are not evenly spread across the U.S. (Fig. 2). For example, since December 2001, canceled projects within the Florida Reliability Coordinating Council (FRCC) jumped nearly 450%. FRCC had just 1,395 MW canceled between January 2000 and December 2001, but since the start of 2002 the figure has surged to 7,661 MW, indicating that even in fast-growth states like Florida developers are revisiting plant economics. Other regions with high levels of canceled projects include SPP, with a 325% increase so far this year; SERC, with a 272% jump; MAAC (266%); Ercot (143%); and NPCC (118%).

The figures for tabled projects are equally dramatic. MACC shows an 887% increase over 2001; SPP has seen a 634% rise; and the numbers for SERC, MAIN, and FRCC are 140%, 136%, and 106%, respectively. In general, most of the canceled projects are in the West; the WECC region has tabled 23,167 MW since January 2000. SERC comes in a close second, with shelved capacity of 17,292 MW over the same period.

A look at the data on a state-by-state basis (Fig. 3) reveals that California, which only two years ago experienced power outages and wild fluctuations in power prices, leads the country with more than 9,000 MW of tabled capacity and 9,692 MW of canceled capacity, for a total of 18,692 MW. Texas weighs in with 6,530 MW tabled and 7,549 MW canceled since January 2000. Illinois has tabled 6,435 MW of planned capacity and canceled more than 9,100 MW since January 2000.

Who's hurting most At the company level (Fig. 4), Mirant Corp., Atlanta, has tabled 7,800 MW since January 2000 -- 6,700 of them since December 2001. Reliant Energy, Inc., Houston, follows with nearly 6,500 MW tabled, 5,500 MW since December 2001. Houston-based Enron Corp., AES Corp., Arlington, Va., and Calpine Corp., San Jose, Calif., round out the top five with 6,304 MW; 4,190 MW; and 4,169 MW tabled, respectively, since January 2000.

Canceled projects by holding company have grown dramatically since January 2000. The holding company with the most canceled capacity is Calpine, with 6,671 MW, more than 3,800 MW since December 2001. However, Calpine officials maintain that 34 of the company's projects are on "hot standby," meaning decisions on their status are pending. In a statement, Calpine's CEO Peter Cartwright says the company postponed the projects to avoid a credit crunch. Duke Energy Corp., Charlotte, N.C., follows Calpine with more than 6,500 MW of canceled capacity since January 2000 -- 3,820 MW of it since December 2001. Constellation (Baltimore), Kinder Morgan, Houston, and PG&E Corp., San Francisco, round out the top five with 4,585 MW; 3,750 MW; and 3,579 MW canceled since January 2000.

Planned natural gas capacity represents 91% of all canceled capacity and 82% of tabled projects. That's not surprising since gas is the fuel for more than 97% of planned generation through 2050. Currently, natural gas powers about 36% of U.S. generating capacity.

Coal makes up 5.75% of the canceled and 6.77% of the tabled projects since January 2000. It fuels about 34% of existing U.S. generating capacity. If there are no more canceled or tabled projects until 2006 -- an unlikely event -- the gas/coal mix will shift to 48% gas and 28% coal.

Finally, one number provides another insight into the ongoing changes within the U.S. electric power industry. During 2001, for every 1,000 MW of tabled and canceled capacity, 980 MW of new capacity came online. The latter has since dropped to 600 MW for each 1,000 MW of tabled and canceled capacity. Fig. 5 shows that tabled/canceled capacity kept pace with new operating capacity through December 2001.

Future shock? To summarize, tabled and canceled capacity continue to rise quickly as companies weigh the need to build more against the need to firm up their balance sheets. This year, holding companies have seen their equity prices slide and their debt ratings slashed. Selling assets to raise cash seems to be their strategy paying down debt and repositioning themselves for the future. But cutting back may turn out to be a double-edged sword, if today's needs end up mortgaging tomorrow's demands.
URL: http://www.platts.com

GRAPHIC: Table, Illustration: Graph: Cumulative capacity by the year, 2000 thruogh July 2002 ; Illustration: Graph: Cumulative capacity by NERC region, January 2000 through July 2002 ; Illustration: Graph: Cumulative capacity, January 2000 through July 2002

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Energy User News July 1, 2002

Energy User News

July 1, 2002

SECTION: No. 7, Vol. 27; Pg. 10; ISSN: 0162-9131

IAC-ACC-NO: 89872294

LENGTH: 1002 words

HEADLINE: Searching for good news: energy providers shot themselves in the foot; Editorial; Brief Article

BODY:
Not so long ago, energy companies like Enron, Reliant, Calpine, and others were market darlings, well positioned to profit from a nearly insatiable demand for a product in short supply. California, it was thought, had botched deregulation, but energy providers there could profit anyway. In states like Texas, it was agreed, customers would soon line up to buy electricity from merchant providers; other states would follow. The Vice President of the United States even suggested that the nation's long-term energy strategy would require the building of at least one new power plant per week for the next 20 years. What greater endorsement could be had?

No one could explain the value of dot-corns, which were traded irrationally and exuberantly. These companies had no earnings, so old-fashioned frames of reference like P/E ratios could not be used to evaluate dot-com investments. Still the rising stock market seemed to lift all investment accounts.

In comparison, investors saw energy companies as safe investments, perhaps because of their conservative utility pasts or perhaps because of the record earnings these companies announced at regular intervals.

How could things have gone so wrong?

You know the gory details. The dot-coin bloom lasted most of a decade, and as the air went out of that balloon, investors also soured on the once-safe energy stocks, which were now perceived as tainted by the on-line energy-trading scandal. Enron was shown to be wearing no clothes. Being forced to restate its earnings downward for a number of quarters, led investors to lose confidence in the firm, which exacerbated a serious situation. The firm declared bankruptcy, but things only got worse at the scandal-engulfed company. Allegations that other firms had engaged in practices such as mark-to-market accounting, wash trades, and market manipulation left the whole energy industry standing naked and accused by the market.

Standard and Poors has wondered whether energy traders can ever be considered sufficiently creditworthy to conduct business. Skilling, Lay, McMahon of Enron are all gone. Other top executives have been forced out, and more than one person has taken his own life over the industry scandals. I fully expect that California will be getting energy rebates because of the conduct of utilities in that state during its energy crisis. FERC has threatened a number of energy marketers with loss of ability to compete in deregulated markets because of their failure to provide requested records.

The capital situation is so bad that merchant power providers have been **canceling turbines** ordered for plants needed to meet demand that may never materialize. Somewhere between 150,000-160,000 megawatts of capacity has been cancelled, postponed, or tabled. Investor confidence in these former media darlings couldn't be lower, which deprives merchant builders of the financing necessary for capital construction. Calpine's response has been typical; it is cutting capital costs by around $ 3 billion over the next two years. This may be a prudent step as some regions are forecasting overcapacity, in part due to overbuilding and in part due to lower than expected loads.

Only FERC's Pat Wood has been able to offer a defense of industry practice, and a tepid one of that, saying that some of the wash trades may be legitimately viewed as price hedges. He may be right, but no one is listening at this stage of the game.

Tom Boren, president and chief executive of PG&E National Energy Group, doesn't expect things to improve soon. At the Deutsche Bank Electric Power Conference held recently in New York City, he said that the power industry may be near the bottom of its business cycle and predicted that the trough would last at least three years, but no more than five. He also said that he believed that revelations related to the trading strategies and demise of Enron were hurting other players.

A few days after Boren's remarks, a jury found Enron's independent auditor, Arthur Anderson, guilty of obstruction of justice. The verdict makes it even more likely that Enron will face a vigorous prosecution, practically guaranteeing that the drip-drip-drip of energy industry revelations will continue for the foreseeable future.

The loss of capital and reduced stock ratings may force utilities and energy traders to pare operations even further. Investment-grade credit ratings are essential to the integrity of the trading operation, so reduced investor confidence and downgraded ratings could force some companies entirely out of the market. The ensuing lowered trading volumes, lack of liquidity in the market, and reduced number of counterparties could increase electricity price volatility, says FERC's Wood.

The energy industry may have booted away an historic opportunity to remake an entire sector of the American economy and lost an opportunity at great profit at the same time, but it has no one to blame but itself.

The market has always dealt harshly with this degree of corruption-and always will. The industry may soon face a shakeout among the largest electricity suppliers, as companies retreat from riskier endeavors or disappear entirely because of positions staked out in the halcyon years.

It is human nature to want to punish those who cheat and deceive us. For these reasons, companies that compete hard but fairly, while offering the best products or services at the best prices, do best in a free economy. They know that ethics are everything. The textbooks are full of examples of what happens when that lesson is forgotten. The recent energy industry scandals have already added more case studies to MBA * programs everywhere. More, I expect, will follow.

Let's resolve to learn from these sordid episodes and get back to competing to see who meets the market need for power and energy services best, and by our actions ensure that no one mistakes us for the bad actors who once plotted to dominate our industry.

IAC-CREATE-DATE: July 31, 2002

LOAD-DATE: August 01, 2002

Generation Week March 27, 2002

Generation Week

March 27, 2002

SECTION: Vol. 4, No. 13; Pg. 1

LENGTH: 1320 words

HEADLINE: Turbine makers work out deals with developers

BODY:
With billions of dollars of potential penalties at stake, turbine manufacturers have decided to lead with a conciliatory stance, negotiating deals with power plant developers rather than insisting that they pay penalties for the turbines they no longer need.

Manufacturers say they are willing to renegotiate deals because they do not want customers to cancel contracts that would be far more lucrative in the long run through development, service and replacement parts and upgrades than taking payment of penalties for contract **cancellations. Also, turbine** makers don't want to push their customers to a competitor. Developers are reworking deals to lessen what could be a significant financial hit should penalty clauses for cancelled equipment kick in.

The potential dollars under negotiation are staggering. According to a year-end 2001 estimate by Platts/RDI, publisher of Generation Week, some 90,000 MW of capacity has been deferred or canceled in North America. That figure has only increased within the last two months. Estimates are that the attendant turbine-generator sets needed to generate that now deferred or canceled capacity are worth more than $ 10-billion.

Over the past several years, the big players in the merchant energy industry bought up huge numbers of turbines to ensure that they would have enough equipment on hand to build out their development programs. Calpine Corp. bought or ordered at least 80 turbines in 2001. Calpine placed the orders with GE Power Systems, Siemens Westinghouse and Toshiba for delivery between 2002 and 2005.

PG&E National Energy Group bought 44 turbines, representing 13,700 MW, in 2001. Mirant -- Southern Energy International at the time -- bought 55 turbines from General Electric. And Entergy spent $ 1.9-billon for 4,000 MW of GE turbines.

Now, many firms are backtracking on those same deals. In the past two months, several merchant energy firms have canceled or deferred projects totaling 26,275 MW. Calpine had planned to have 70,000 MW in operation, under construction or in development by 2005, but put 34 projects totaling 15,100 MW on hold in February in response to poor market conditions.

Calpine has been finalizing agreements with equipment suppliers to adjust delivery timing and related payment schedules to reflect its revised development timetable.

Calpine has cancelled 34 turbine orders, at a cost of around $ 161-million, and deferred 81 more turbines. The San Jose, Calif.-based firm said it would save around $ 3-billion in capital expenditures, $ 1.2-billion in 2002 and $ 1.8-billion in 2003, as a result.

Commerzbank estimated that Calpine's capital expenditure prior to the latest announcement was about $ 5-billion for 2002 and 2003, so that the turbine cancellations would cut that total by more than half.

The deferred turbine orders have been re-worked with GE Siemens and Toshiba to adjust the timing of delivery and related payment schedules. Calpine said it would not incur any additional cash charges as a result of these revised arrangements.

Calpine now has 127 F-type gas turbines on order for delivery between 2002 and 2007. The company said it would not rule out the possibility of further delivery rescheduling, if market conditions required it.

The turbine plans are just one part of a larger strategy by Calpine to reduce spending and to raise liquidity through securing debt facilities and several asset sales. Calpine said March 12 that it had secured a new $ 1-billion credit facility and renewed a $ 400-million credit facility (GW 3/20).

Other major developers have downsized their development plans. They will likely have to follow Calpine's example and rely on turbine manufacturers to renegotiate contracts for payment and delivery in order to avoid millions of dollars in fines.

Entergy Corp. has contracts for 15 General Electric turbines slated for delivery by 2005. Failure to take delivery would result in penalties tied to the contracts and credit facilities in the $ 200-million to $ 250-million range.

If renegotiations fail, developers also are looking at taking delivery of units and warehousing them until conditions improve, marketing the new machines and/or the sites where projects were planned to others and, in some cases, possibly taking units planned for unregulated projects and repowering existing plants in a regulated utility.

Whatever the method of coping with oversupply, equipment orders are rapidly slowing. According to a recent J.P. Morgan report, worldwide orders for gas and steam turbines in 2002 will drop by 50,000 MW to 60,000 MW, equivalent to roughly 33% of 2001 volumes, due to the U.S. the market slow down.

While the options are many, industry watchers agree that negotiating is the least painful choice for all parties. "Manufacturers are bending over backwards to work with people so they don't cancel orders," said a small, West Coast-based developer who requested anonymity.

GE officials acknowledge that discussions are under way with several clients to save deals. "In some cases, we are pushing orders out or turning dollars into service annuities or service work; we're trying to accommodate our customers," said Dennis Murphy, spokesman for GE's Power Systems Division in Atlanta.

Turbines and attendant long-term service agreements are a major money maker for GE. Its Power Systems Division, of which turbines are a major component, in 2001 was the parent's second-largest source of both revenues and profits. Power Systems reported $ 20.2-billion in revenues in 2001 against $ 14.9-billion in 2000; and $ 5.2-billion in profits against $ 2.8-billion in 2000.

"The manufacturers are looking to delay terms, restructure deals with the solid clientele, the developers they know will be there for a long time, the FPLs, the Dynegys, the Calpines, the Mirants," said Joseph Umberto, vice president of business development for the engineering-construction firm Burns and Roe, Oradell, N.J.

"They [manufacturers] know that when confidence is regained in the economy, when Enron is finally out of the news, that things will happen [in the generation industry]." Still, accommodate to GE doesn't mean capitulate, according to Donald O. Swenson, senior consultant with Black & Veatch, Overland Park, Kan.

"It all depends on how well the buyer can renegotiate its deal," Swenson said. "GE contracts are pretty tight."

Some companies forego renegotiating deals, instead taking delivery on schedule and placing units in cold storage, like Mirant Corp., which on Jan. 30, announced it was suspending construction on two plants and warehousing turbines for two additional projects.

Rather than warehouse for its own use at a later date, a company might consider selling its new turbine to a domestic player, which might have an attractive site, but be short the hardware, or even ship that equipment out of the country, possibly to Mexico, Canada, Taiwan, or Brazil, Umberto said.

Another option for developers with regulated utilities is to take the new units and repower an existing facility -- provided the idea can get through the affected state's public utility commission.

New Orleans-based Entergy's Chief Executive J. Wayne Leonard raised some eyebrows when he told analysts one option for at least some of his company's 15 soon-to-be delivered turbines was to repower facilities at regulated sites.

Leonard, sources said, hinted that Entergy was getting pressure from personnel at the Louisiana Public Service Commission to make up capacity shortfalls by repowering rather than buying power.

Earlier this year, Leonard admitted that with the large amount of merchant capacity under construction in Entergy's territory, it might even prove more economic for the company to purchase power rather than to repower units and place the units in ratebase.
URL: http://www.platts.com

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Exhibit

PJM-4

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Private securities
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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 Washington, D.C. this 25th day of April, 2003.

Michael J. Thompson

Counsel for
PJM Interconnection, L.L.C.