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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.	)	**Docket Nos. EL05-148-000**
	)	**and ER05-1410-000**

COMMENTS OF
PJM INTERCONNECTION, L.L.C.
ON TECHNICAL CONFERENCE

PJM Interconnection, L.L.C. ("PJM"), in accordance with the Commission's April 20, 2006 order[1] and May 1, 2006 notice in these proceedings, submits its comments on the June 7-8, 2006 technical conference ("Technical Conference") regarding the details of alternative methods for satisfying capacity obligations under PJM's proposed Reliability Pricing Model ("RPM"). The record developed through the Technical Conference underscored that PJM's proposal for the shape and parameters of the RPM auction's downward sloping variable resource requirement ("VRR") curve is reasonable and well-supported. The Technical Conference also showed that the Commission must be very careful in developing the details of the long-term fixed resource requirement alternative to ensure that load-serving entities ("LSEs") participating in that alternative commit resources on a comparable basis to LSEs participating in the RPM auctions, and under no circumstances are allowed to double-commit their resources: once by long term plan to serve their own loads and again by sale into the RPM auction to serve other loads.

I. LONG-TERM FIXED RESOURCE REQUIREMENT ALTERNATIVE

The Technical Conference revealed a significant degree of consensus on the core elements of the long-term fixed alternative, with most controversy focused on the extent

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1 PJM Interconnection, L.L.C., 115 FERC ¶ 61,079 (2006) ("April 20 Order").

to which parties that elect to remove their loads from the RPM auctions may still sell their resources into those auctions. Broadly speaking there was consensus among the panelists at the technical conference that LSEs electing this alternative should:

- Commit to the alternative for a term of at least five years (with many arguing for a longer commitment, or one triggered only by a change in state regulatory regimes);
- Adhere to the same locational and operational reliability obligations as LSEs that participate in the RPM auctions;
- Serve load for which that LSE has an established long-term relationship during the term of the election, based either on state law or franchise, or a long-term contract;
- Pay a penalty for non-compliance of twice the Cost of New Entry; and
- Face heightened penalties (including possibly a ban on further election of the alternative) for willful or repeated violations.

The area of greatest dispute concerns an issue that should be peripheral to those that claim they do not wish to participate in the RPM auctions: the rules under which such LSEs can turn around and sell their capacity resources into the RPM auctions, notwithstanding their choice to remove their loads from those auctions. This question should be vital to the Commission, as it concerns the rules for interaction between two parallel market systems, an area rife with the potential for abuse. The showing that such abuse is likely was compelling, and was not rebutted. The parallel systems are being established to address the concerns of some entities that RPM is not compatible with certain regulatory obligations; that parallel structure should not become a vehicle for market participants to seek a comparative economic advantage. Accordingly, it is essential that the Commission ensure that LSE obligations in the two systems are as comparable as they can be made; and that the two systems are kept separate, without one unfairly leaning on the other.

A. Time Period of Commitment.

In its written submission before the Technical Conference, PJM advocated a minimum five-year commitment by parties electing the long-term fixed alternative.[2] At the Technical Conference, Mr. Ott agreed with the parties that advocate an eight to ten year commitment period based on the typical business cycle.[3] As Mr. Ott explained, five years is the minimum needed to match the RPM commitment period, and a longer period—eight to ten years—will better reflect both the typical business cycle and the traditional integrated resource plan period. Id.

RPM carries forward the current convention that the capacity planning and commitment year (known in RPM as the Delivery Year) extends from June 1 of a calendar year to May 31 of the subsequent calendar year.[4] When RPM is fully implemented, the base residual auction for a given Delivery Year will be held in the month of May that is four years before the start of such Delivery Year.[5] Counting the Delivery Year addressed in the auction, RPM effectively establishes a regional capacity supply plan for a period of five Delivery Years. This same basic five-year approach will apply at RPM's initial implementation, except that PJM will hold initial auctions for all of the interim years before the first four-year forward auction.

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2 Supplemental Affidavit of Andrew L. Ott on Behalf of PJM Interconnection, L.L.C. on Technical Conference Issues, filed May 30, 2006 ("Ott Supp. Aff.") at 9.

3 Tr. 280-82 (Mr. Ott, PJM).

4 See PJM's August 31, 2005 initial filing in these dockets ("August 31 Filing"), at Tab B, The New PJM RAA, sections 1.10 and 1.59.

5 See August 31 Filing, Tab C, PJM Tariff Revisions, Attachment Y, section 5.4(a).

Therefore, assuming the first RPM Delivery Year starts on June 1, 2007, PJM will hold auctions in 2007 for the 2007-08, 2008-09, 2009-10, 2010-11, and 2011-12 Delivery Years.[6] At a bare minimum, to assure no lesser commitment than the RPM auction participants, LSEs electing the long-term fixed alternative must commit to the alternative for those five Delivery Years.[7]

PJM would support extending that commitment to eight to ten years, as Mr. Ott stated at the conference.[8] This would conform to the typical capacity business cycle, as shown by Professor Hobbs' analysis.[9] For this purpose, the relevant business cycle is that of the capacity market as a whole, and not the development cycle of an individual generating plant as suggested by AEP.[10] Requiring commitments to span a likely business cycle ensures that LSEs electing the long-term fixed alternative cannot time that larger market, riding it when it is long and selling to it when it is short, which is exactly

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6 PJM presumes that most (if not all) LSEs that wish to elect this alternative will do so when RPM is first implemented, when a series of auctions are held in quick succession for the first five Delivery Years. If an LSE does not elect the alternative until after the first year, then it must commit for five Delivery Years, with the first such year beginning four years after the base residual auction. For example, an LSE that has not previously elected the alternative, but wishes to do so before the base residual auction held in May 2008, must commit for the 2012-13, 2013-14, 2014-15, 2015-16, and 2016-17 Delivery Years.

7 Tr. 280:21-281:7 (Mr. Ott).

8 Tr.282:8-12 (Mr. Ott).

9 Tr. 226:10-14. Attachment A to these Comments contains a memorandum from Professor Hobbs setting forth his answers to all of the questions posed to him by the Commission staff at the end of the first day of the Technical Conference.

10 Tr. 267:2-14 (Mr. Stoddard, Mirant). See also Tr. 337-8 (Mr. Stoddard, Mirant)

the concern identified in the April 20 Order[11] and by the Commission's staff at the conference.[12]

An eight to ten year commitment period also would match the traditional Integrated Resource Planning ("IRP") period. Indeed, AEP's Mr. Baker acknowledged that AEP's system used such a longer IRP period.[13] Since the long-term fixed alternative is largely intended to allow vertically integrated utilities to continue an IRP approach, it is reasonable to require such a utility to commit to the alternative for the same time period addressed by its IRP.

The arguments for a shorter time period are not convincing. AEP simply asserts that the commitment period should be the same as RPM (which AEP understood to be four years, rather than the five Delivery Year period discussed above).[14] As Mr. Baker acknowledged, his proposal for a relatively short commitment does not address the Commission's concern that LSEs could game their participation in the alternative, because he viewed that concern as unwarranted.[15] But there is no reason to expect that participants would not maximize their economic advantage if given the option, and AEP certainly offers no such reason.

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11 April 20 Order at P.111.

12 Tr. 265:10-16.

13 Tr. 264:6-15 (Mr. Baker, AEP) ("When AEP looks at its plans . . . we look out ten years or so").

14 Tr. 268:15-19 (Mr. Baker, AEP).

15 Tr. 264:2-5; 269:11-13 (Mr. Baker, AEP).

Dayton proposed five years, believing (mistakenly) that would lock the LSE in for one year longer than the Delivery Years addressed in the RPM auctions.[16] As shown above, however, the first five Delivery Years are addressed through auctions in RPM's first year, so Dayton's proposal would leave it free to depart the long-term fixed alternative as early as the auctions held in 2008, and any time thereafter. Dayton's only argument in support of its proposal was that, beyond five years, load forecast uncertainty becomes too great a factor to allow for a meaningful election.[17] While this underscores PJM's demonstration (discussed below in Section I.C.3.a) that load forecast uncertainty increases forward installed rserve margin ("IRM") uncertainty, load forecast uncertainty by itself does not justify Dayton's proposal to limit the election to a period half as long as a typical Integrated Resource Plan would address.

Accordingly, the Commission should find that an appropriate term for the long-term fixed alternative is eight to ten years. PJM also would not object to an indefinite commitment period, changeable only upon a change in a state's retail regulation status, e.g., if a state that has not allowed retail competition decides to allow such competition.[18]

B. Eligibility Criteria

For the LSE's long-term election to be meaningful, the loads it serves must remain with that LSE for the duration of its election. If a customer could switch between LSEs that participate in RPM and those that elect the long-term fixed alternative, then it might do so as a result of a temporary pricing advantage arising from the alternative

16 Tr. 272:8-11 (Mr. Horstmann, Dayton).

17 Tr. 270-1 (Mr. Horstmann, Dayton).

18 See, e.g., Tr. 277-8 (Mr. Nauman, Exelon); Tr. 298:4-10 (Mr. Shanker, FPL).

capacity constructs. As Mr. Ott explained, if the load switches from an LSE under the long-term fixed alternative to an LSE using the RPM auctions, then the new LSE would be forced to cover the load obligation on a shorter time frame than the RPM auction cycle.[19] But RPM has no mechanism for load to acquire capacity after the base residual auction, as all capacity is committed four years forward.

For these reasons, the long-term fixed alternative should be available only in zones where the LSE can demonstrate that it has a clearly established, protected relationship with its load for the term of the commitment. Id. The LSE could make the required showing either by pointing to applicable state law establishing the long-term load commitment, or with a long-term contract or other long-term relationship with the load, such as a franchise. This could include a municipality or electric cooperative.[20]

Most of the panelists at the Technical Conference agreed that an LSE seeking to elect the long-term fixed alternative should be required to show that its loads will remain with it during the term of that election, and not migrate to RPM.[21] Several added that this could include municipals and cooperatives with identifiable discrete loads.[22] Even AEP agreed that the alternative should be limited to those that can say for the long-term that

19 Ott Supp. Aff. at 12.

20 Tr. 334 (Mr. Ott, PJM).

21 Tr. 300-301 (Ms. Moler, Exelon); Tr.333-334 (Mr. Nauman, Exelon); Tr. 324-326 (Mr. Stoddard, Mirant); Tr. 326-327 (Mr. Wemple, ConEd).

22 Tr. 325-26 (Mr. Stoddard, Mirant); Tr. 326:9-12 (Mr. Wemple, ConEd).

they have the load and they have the generation, and they are "pulling both of those out of the RPM market."[23]

These limitations are appropriate—indeed, essential—given the nature of the exception at issue. As Mr. Ott has repeatedly emphasized, a primary objective of RPM is to assure that all load in the region is accounted-for, and all resources needed to serve that load are identified and committed, well in advance of the Delivery Year.[24] If part of the regional load is ignored in the advance commitment process, then the region's reliability needs (not only the overall resource requirement, but also the region's locational and operational reliability needs) cannot be assessed accurately, and the arrangements needed to assure reliability cannot be accurately determined in advance. Id. Absent a comprehensive forward accounting, the system will remain subject to the type of near-term reliability violations that have occurred recently and required extraordinary out-of-market solutions. Id.

The long-term fixed alternative provides an opportunity for LSEs to remove their loads and generation from the RPM auctions for an extended period, but it does not eliminate the need for that essential and comprehensive forward matching of loads and resources. The LSE electing this alternative meets that need by identifying its loads and assuring that the RPM auctions shall not be responsible for obtaining resources for those loads during the term of its election. Under those conditions, the RPM auction process can exclude those loads from RPM's advance resource commitment process. Therefore,

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23 Tr. 307:6-9 (Mr. Baker, AEP). See also Tr.307:20-25 (Mr. Baker, AEP). For its part, Dayton's representative said only that Dayton would not oppose participation by others. See Tr. 308 (Mr. Horstmann, Dayton).

24 See August 31 Filing, Tab E, Affidavit of Andrew L. Ott ("August 31 Ott Aff.") at 14, ll. 23-44; Ott Supp. Aff. at 9, ll. 5-20.

to assure reliability, the LSE electing this alternative must show with certainty that it will remain responsible for those loads for the duration of its election, and that they will not fall back on the rest of the PJM region, which will not have procured sufficient resources in advance to assure reliable service to those loads.

These limitations also are reasonable because the long-term fixed alternative is not the only option for LSEs that wish to limit their exposure to the RPM auction clearing prices. As Mr. Ott explained, LSEs can self-supply in RPM (identifying their owned or contracted resources with a price-taker bid so that they both pay and receive the clearing price for those resources), and can take advantage of a flexible self-supply option to manage their exposure to quantity uncertainty in the RPM auction process.[25] Demand-responsive customers also have two options to avoid RPM capacity charges. They can be designated as Interruptible Load for Reliability as late as three months before the Delivery Year, thereby earning credits against the otherwise applicable RPM charges, or they can offer their demand response capability into the RPM auctions on a forward basis, and (if they clear) receive revenues based on the capacity clearing price. Id. Such LSEs effectively are committing to voluntary load curtailment in exchange for avoiding capacity responsibility. Finally, an LSE can exercise the option that always has existed under the RAA to excuse itself from the pooled capacity obligation by effectively removing itself from the power pool/energy market.[26]

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25 Ott Supp. Aff. at 8. See also August 31 Filing, Tab C, PJM Tariff Revisions, Attachment Y, section 5.2 (describing self-supply in RPM, including option for contingent designation of resources as self-supply).

26 Such an LSE must install the equipment necessary to prevent its leaning on the PJM Region's capacity during emergencies and must enter into a control area to control area agreement with PJM. Ott Supp. Aff. at 8. See also August 31 Filing,

In sum, the long-term fixed alternative should only be available to LSEs that can demonstrate that the rest of the PJM Region will not be responsible for their loads for the duration of their election of the alternative. This may include municipalities and cooperatives with identifiable discrete loads for which they have state-recognized or franchise responsibilities. Parties (such as individual demand responsive customers) that wish to avoid the RPM auction clearing prices have other options to achieve that result.

C. Rules to Prevent Double-Commitment of Capacity and Gaming.

1. Capacity Commitments in the RPM Auctions and Long-Term Fixed Alternative Must Be Comparable and Cannot Be Double-Counted.

Capacity resources that are needed to assure reliable service to loads under the long-term fixed alternative cannot also be committed as capacity resources for loads in the RPM auctions. For the long-term fixed alternative, those committed capacity resources must be identified in advance for an extended period and, once so identified, may not be committed to RPM auction loads. This simple principle is essential to preserving regional reliability. If an LSE electing the long-term fixed alternative commits what it believes to be excess capacity to the RPM auctions, but later finds that such capacity is needed for its loads under the alternative (e.g., because load is higher than was forecast four years earlier), then the region as a whole will be short of needed capacity. The LSE's mere payment of penalties in the Delivery Year will not eliminate the resulting capacity shortage and reliability consequences.

Tab B, The New PJM RAA, section 5.1.3(c). This subsection has been carried over from each of the currently effective RAAs.

Moreover, unequal capacity commitments in the two parallel capacity options raise additional concerns of equity and effectiveness. As Mr. Ott explains in his Supplemental Affidavit, LSEs in PJM are interdependent; all rely on one another's capacity resources to assure service to all loads in an emergency; and all must commit their share of capacity to avoid unfairly leaning on one another's resources.[27] Such interdependence is inherent in the way PJM operates the system, and basic fairness requires all LSEs to make comparable capacity commitments. Mr. Ott rejected unrealistic suggestions to address the equity concern by targeting curtailments to LSEs whose resources are determined to be underperforming in real-time, and emphasized that the better answer was to ensure comparable commitments by all LSEs, regardless which alternative they pursue.[28]

Comparable commitments also are essential to ensure that the RPM auctions are effective in achieving their objectives. As Mr. Ott explained, implementation of the long-term fixed alternative under poorly designed rules "could effectively steepen, or even make vertical, the slope to the demand curve" because the capacity clearing price "would fall substantially, perhaps to zero, whenever aggregate available supply exceeded the pre-determined fixed capacity requirement available to LSEs that wish to opt out of the auction."[29] When those unequal conditions exist, LSEs will have an incentive to elect the long-term fixed alternative, because it will reduce their capacity requirements. Since such an LSE "would acquire less capacity than the auction would have bought for the

27 Ott Supp. Aff. at 7-9.

28 Tr.319:19-320:8; 321:15-322:8 (Mr. Ott, PJM).

29 Ott Supp. Aff. at 11.

load, the supply not acquired by the LSE would remain in the auction and increase the supply surplus for the load that remains in the auction."[30] Increasing the supply surplus in turn will reduce the capacity clearing price in the auction. As a result, the benefits of a sloped demand curve—including greater revenue stability and reduced incentives for generators to exercise market power in the capacity market—would be significantly compromised. Id.

All panelists at the conference except those from AEP and Dayton emphasized that this was their greatest concern with the long-term fixed alternative, and urged the Commission to adopt rules that would limit these potential adverse effects.[31]

2. The Commission Could Address Most of these Concerns Simply by Providing that LSEs that Elect the Long-Term Fixed Alternative May Not Sell Their Resources into the RPM Auctions.

One way to address most of the above concerns would simply be to provide that LSEs that wish to remove their loads and resources from the RPM auctions cannot sell their resources in the RPM auctions. This would be consistent with the purpose of the alternative, which is to provide a mechanism for vertically integrated utilities that retain traditional load responsibilities to avoid the uncertainties of the RPM auction and instead follow a traditional integrated resource plan. This also eliminates the possibility that capacity might be double-committed to serve both loads in the long-term fixed alternative and loads in the RPM auctions. In addition, this approach avoids the concern that

30 Id. at 12.

31 See, e.g., May, 2006 Pre-Conference Statement of Mr. Shanker, at 7-8, 12-14; May 30, 2006 Pre-Conference Comments of Consolidated Edison Energy, Inc., at 3-4; May 30, 2006 Pre-Conference Comments of Robert B. Stoddard, at 3-4; May 30, 2006 Position Statement of Exelon Corp. for Technical Conference on RPM.

interaction between the two parallel capacity constructs might prevent the RPM auctions from achieving the objectives that require RPM to be adopted in the first place.

This approach also leaves to LSEs in the long-term fixed alternative all decisions about how best to assure that they have sufficient capacity to meet their loads over the period they have elected that alternative. There is no need to define for them a capacity commitment that is comparable to that of the RPM auction LSEs, and above which their capacity is deemed to be excess.

3. Alternatively, LSEs Electing the Long-Term Fixed Alternative Could Offer Excess Capacity into the RPM Auctions, with Such Excess Defined as any Quantities Over the IRM Plus Three Percent.

Rather than prohibit all sales into the RPM auctions by LSEs that elect the long-term fixed alternative, the Commission could allow such LSEs to sell their excess capacity into RPM. But that raises all of the concerns noted at the beginning of this section, and therefore requires a careful definition of such LSE's excess capacity.

As PJM demonstrated, to ensure comparability, an LSE electing this alternative must designate in its long-term plan resources at a level of IRM plus three percent.[32] Two percent is needed for the load forecast uncertainty inherent in a long-term four-year forward commitment;[33] and one percent is needed to reflect that such an LSE can no longer rely on the forced outage diversity of the PJM Region.[34]

PJM emphasizes that it is not asking the Commission to set the Installed Reserve Margin for any LSE in the PJM Region. Indeed, RPM makes no change to the manner in

32 Ott Supp. Aff. at 9-11.

33 Id. at 10, ll. 2-30.

34 Id. at 10:31 to 11:14.

which the PJM Board of Managers, with the advice of stakeholders (including the states), determines and sets the IRM for the PJM Region.

The current method of implementing that IRM is through a fixed penalty amount assessed on an LSE for every megawatt that it falls below the IRM. This administrative penalty structure was intended to prevent the reserve margin from falling below the specified IRM (by penalizing every LSE to the extent it did not achieve that standard).[35] However, recently identified reliability violations have revealed deficiencies in the current fixed-penalty construct.[36] To address these deficiencies, RPM adds an auction mechanism with variable pricing over a range of resource requirements (instead of a single fixed penalty at the IRM), but does not change the method of determining IRM or the desired level of reliability.

To leave no doubt, PJM does not now operate the system, and never has operated the system, to achieve the established IRM on average over time. Dropping below the 15% reserve margin half the time (or anywhere near half the time) never has been an accepted operating practice in the PJM Region; rather, it is a circumstance that may be tolerated in the exception, not the rule, but only if there are adequate protocols in place to mange the resulting vulnerabilities. As Mr. Ott explained, "[i]f you go in with less than

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35 See August 31 Filing, Transmittal Letter at 37-39.

36 Id. at 40-46. Professor Hobbs' showing that a fixed penalty charge structure can lead to boom-bust volatility around the IRM (id. at 45-46) is not a description of the current state or a desired reliability state; rather, that is an unacceptable outcome to be avoided by reforming the capacity construct. The design shortcoming he highlights is currently being revealed through generator revenue deficiencies, retirements, and price volatility. By administrative mandate, the current system is not allowed to dip below IRM. Concern over the future viability and effectiveness of that administrative mandate is what prompts this filing. In short, the reliability objective remains the same; what is needed is a construct that is more effective at achieving that objective.

15 percent you may not on a given day have enough operating . . . units capable of operating to meet the peak load. But then you have certain operating parameters that would get you through that very thin period."[37] Mr. Ott analogized the capacity requirement to the reliability requirement to maintain a certain level of regulation, observing that if PJM tried to justify average regulation over two hours of 300, where one hour was 600 and one was zero "I would be thrown out of various reliability councils . . if we ran the system like that."[38] In sum, he warned that "the cost of failure is so immense here" that "the IRM is really a number you don't want to go below very often."[39]

RPM is intended to meet this same reliability objective, i.e., producing actual reserve margins that meet or exceed the IRM in nearly all years. Whether this effectively results in slightly better reliability than the one-day-in-ten-years loss of load probability is not the point; what matters is that it is the same reliability objective as the current system. Therefore, in assessing potential VRR curves, PJM considered whether it was likely to produce actual reserve margins that fell below the required IRM only on limited occasions, such that those circumstances could be managed through operating protocols.

Similarly, in setting the rules for an exception to the RPM auctions, the Commission is not being asked to set an IRM for LSEs that elect this alternative, or to change the objective that the region should in most years meet or exceed the identified IRM. Rather, the goal is to set rules that ensure equivalent commitments by LSEs under

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37 Tr. 10:9-13.

38 Tr. 23-24.

39 Id.

either alternative, and that limit the likelihood that the exception will frustrate the objectives of the RPM auctions.

a. A Long-Term Plan Must Commit Additional Resources to Account for Increased Long-Term Load Forecast Uncertainty.

The evidence of the need to increase extended-horizon reserve margins for increasing load forecast uncertainty is clear and unrebutted. Mr. Ott testified that the IRM calculations for the PJM Region "always have included a component to address Load Forecast Uncertainty ("LFU")."[40] Load forecast uncertainty is inherent in every determination of required reserve margins, and that uncertainty increases as the forecast extends farther in time. Based on the method PJM planners traditionally use to account for LFU, which PJM confirmed with a comparison of recent forecasts against actual weather-normalized loads, the IRM for a planning year four years forward must be increased by two percentage points.[41]

No party rebutted this showing. To the contrary, the record only reinforces these conclusions. Mr. Nauman, who testified that he was involved in the determination of reserve requirements for his company, emphasized that "load forecast uncertainty for the future years is real."[42] He explained that load forecast uncertainty "grew as you looked into the future" so that they "would come up with . . . 18 percent, three years in advance, in order to make sure you showed up with 15 percent."[43] He therefore concluded that

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40 Ott Supp. Aff. at 10.

41 Id. at 10 & Appendix A.

42 Tr. 383:8-9.

43 Id., at 383:2 and 383:5-8.

load forecast uncertainty "needs to be accounted for in one way or another."[44] Dayton's representative at the Technical Conference similarly acknowledged the importance of this factor, arguing that the long-term fixed alternative election should be only five years because "you start to introduce a lot of forecast error after year five."[45]

Even AEP's submissions in this proceeding show that it has explicitly accepted PJM's method of determining IRM based on increased load forecast uncertainty over time. AEP attached to its October 19, 2005 Protest in this proceeding a stipulation it executed with PJM to resolve proceedings before the Kentucky Public Service Commission ("KyPSC"), which also was filed with and approved by this Commission. That stipulation recognized "PJM's obligation to ensure an adequate reserve margin consistent with maintaining an acceptable level of reliability;" set forth in a detailed attachment PJM's methodology for determining reserve margins; and provided that AEP would not have to pay PJM to maintain adequate capacity "[s]o long as AEP maintains adequate capacity <u>in accordance with applicable PJM capacity requirements</u>."[46] The stipulation's attached description of PJM's reserve margin methodology states that the load model used in those determinations "recognizes the increased forecast uncertainty associated with longer planning horizons."[47] The attachment explains that this

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44 <u>Id</u>., at 383:10-11.

45 Tr. 271:1-2.

46 "Motion to Intervene and Protest of American Electric Power Service Corp.," Appendix A to Attachment C, at paragraph 2 (emphasis added).

47 <u>Id.</u>, Attachment A to Appendix A to Attachment C, at p. 11. The quoted text appears on the 56th page of the pleading and attachments as filed at the Commission.

uncertainty is addressed through a "Forecast Error Factor" which typically is "0.5% error in the first planning period and increase[s] . . . by 0.5% for each succeeding planning period of the study" up to a maximum of "3.0% error [that] occurs six years forward in time." Id. This document describes PJM planners' long-standing practice of reflecting increased load forecast error, as referenced by Mr. Ott in his pre-conference written submission.

When it approved the stipulation, the KyPSC noted that "the parties have attached to the Stipulation the detailed methodology used by PJM to determine an adequate reserve margin" and observed that it "is familiar with that methodology and finds that it is reasonable for use on the PJM system."[48] The detailed IRM methodology description attached to the KyPSC Stipulation predated RPM, but has not been changed and remains the governing document, posted on PJM's website,[49] for the PJM Region's IRM determinations.

Although AEP presented no evidence to contradict PJM's showing that forward load forecast error requires additional resource commitment, AEP nevertheless maintains that it should be trusted to address load forecast uncertainty in its long-term plan in any way it sees fit. But this ignores that AEP is integrated into the PJM Region and now is subject to this region's applicable capacity requirements, including PJM's long-standing technical planning guidance that load forecast uncertainty is addressed by increasing the IRM for forward commitment periods by set amounts. Moreover, AEP never explains why the rest of the PJM Region should assume the reliability risk if AEP does not

48 Id., Attachment C at p. 9.

49 The document is available at http://www.pjm.com/planning/res-adequacy/downloads/20040621-white-paper-sections12.pdf.

adequately address forward load forecast uncertainty. While AEP would pay financial penalties if it turns out that the resources it committed in advance are insufficient to serve loads that increased more than its forecast, the reliability consequences will fall on the rest of the PJM Region if AEP has committed what it thought were excess resources to serve other PJM loads in the RPM auctions, but now needs those same resources to assure service to its own loads.

Notably, the only party that expressly proposed to address load forecast uncertainty solely through penalties proposed vastly higher penalties than PJM and all other parties have proposed. Mirant's panelist Mr. Stoddard explained that his proposal is an interrelated package, and bases the long-term fixed capacity commitment directly on IRM (with no LFU adders) only because it also assumes when calculating the LSE's deficiency that it has been deficient by that amount <u>for every day of the Delivery Year</u>.[50] This type of penalty normally is reserved for willful violations, but Mr. Stoddard proposed it as a means of providing absolute assurance that an LSE electing the long-term fixed alternative will properly manage its load forecast uncertainty.

Nor is it appropriate to allow AEP to wait until shortly before the Delivery Year and commit any needed additional resources at that time based on an updated load forecast. Although the RPM auctions address load forecast uncertainty in this way, such a changed commitment would be contrary to the defining principle that this is a <u>long-term fixed</u> alternative to participation in the RPM auctions. The LSE electing this alternative should designate sufficient resources <u>at the outset</u> to ensure reliable service to the entire load it wishes to remove from the RPM auctions, so that the RPM auctions can safely

50 Tr. 356-7.

disregard this load, and to prevent the LSE from "defining down" its obligation and selling the excess into the RPM auctions in a fashion that is damaging to the auction clearing process. These resources should now be committed to the long-term fixed alternative and not be allowed to sell into the RPM auctions to meet the rest of the region's capacity obligations. One simply cannot commit the same resources to each of the parallel capacity options.

b. A Long-Term Plan Must Commit Additional Resources to Offset the Risk of Degradation in Unforced Outage Rates.

As Mr. Ott explained, the load participating in RPM "will be covered by a large pool of resources with sufficient diversity of forced outages, resulting in a stable total unforced capacity value."[51] But the resources of an individual LSE in the long-term fixed alternative "will not have the same benefit of pooled resources" and consequently faces a greater risk that its unforced capacity value will degrade in the delivery year. Id. Therefore, such an LSE must designate at the outset additional resources equal to one percent above IRM to manage this risk and help maintain regional reliability. Id.

As Mr. Ott summed up both for this issue and load forecast uncertainty:

> if you're on the fixed-resource requirement, it's not reasonable to allow that entity to manage its uncertainty, its forward uncertainty, whether it be generation performance or load forecast performance . . . [i]t shouldn't be able to lean on the market to manage that uncertainty, because it has elected to go out to the fixed-resource requirement alternative. So, it shouldn't be able to take those resources that it [has] designated, to cover that uncertainty and have them show up over in the market. All we're trying to quantify, is what that uncertainty is.[52]

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51 Ott Supp. Aff. at 11.

52 Tr. 387-88.

D. Locational and Operational Reliability Obligations.

In his pre-conference affidavit, Mr. Ott explained that the long-term fixed alternative "must recognize and support the locational and operational reliability elements of the new regional capacity construct," so that all LSEs in the region, whether or not they participate in the RPM auctions, will contribute to meeting these obligations.[53] LSEs under the long-term fixed alternative must meet these obligations "by committing capacity resources of the type and in the place needed." Id.

To meet the locational requirement, LSEs under the long-term fixed alternative that serve loads in an import-constrained LDA must include in their designated resources a specified share that is located in that LDA. Id. Similarly, if RPM requires commitment of additional resources to ensure adequate capability to provide load-following or quick-start service, then an LSE under the long-term fixed alternative "also must designate a sufficient share of resources in its zone to support the provision of those services." Id.

Several parties supported these requirements,[54] and none disputed them. AEP and Dayton both acknowledged, in principal, that they should meet such requirements.[55]

E. Deficiency Penalties and Consequences of Repeated or Willful Violations.

Because "[t]he deficiency charges must be sufficiently high to ensure compliance," PJM proposes a deficiency charge "that equals two times the cost of new

53 Ott Supp. Aff. at 12-13.

54 See, e.g., Shanker Pre-Conference Statement at 4; Stoddard Pre-Conference Statement at 5.

55 Tr.423:11-25 (Mr. Baker, AEP and Mr. Horstmann, Dayton).

entry."[56] Most panelists agreed with this penalty level. Mr. Stoddard proposed that the penalty should be assessed on an annual basis, but his proposed very large penalty presumes that LSEs electing the long-term fixed alternative are not required to reserve an additional three percent to cover forward uncertainty.[57] PJM's opposition to that much higher penalty level assumes that LSEs will be required to designate an additional three percent above IRM to protect the rest of the region from the consequences of their forecast errors.[58]

PJM also proposes that an LSE that fails to comply should face escalating penalties for repetitive noncompliance, including potentially a ban on that LSE's participation in the long-term resource plan in the future, because regional reliability could be threatened by repeated non-compliance.[59] At the Technical Conference, Mr. Ott elaborated on the willful non-compliance that might threaten reliability and warrant prohibiting an LSE from continuing to use the long-term fixed alternative.[60]

II. SHAPE AND PARAMETERS OF THE VRR CURVE.

In the April 20 Order, the Commission found that a downward-sloping demand curve may be a just and reasonable component of RPM, but directed its staff to gather additional evidence regarding the parameters affecting the height, slope, and shape of the demand curve.[61]

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56 Ott Supp. Aff. at 13.

57 Tr. 356-57.

58 Tr. 357:11-17.

59 Ott Supp. Aff. at 13.

60 Tr. 361-62.

61 April 20 Order at P.109.

PJM devoted considerable resources over the past two years to the effort to design a VRR curve that seems most likely to provide the best balance between assuring reliability and limiting consumer costs. PJM considered a range of different curves, including the current vertical demand curve, a curve based on the value of lost load, three downward-sloping curves that set the cost of new entry at differing installed capacity levels, and multiple variations of those curves. To provide a sound basis for choosing from among these possible curves, PJM retained Professor Benjamin F. Hobbs of the Johns Hopkins University to perform sophisticated dynamic economic modeling of the likely performance of the curves under a wide variety of assumptions. PJM entered this process with no preconceived notions about the "right" curve, and gave Professor Hobbs no direction to support one curve over any other curve.

Similarly, PJM retained Mr. Raymond M. Pasteris, a consultant with extensive experience in power project development, to prepare an independent estimate of the cost of new entry, which is one of the key parameters in the VRR curve. Mr. Pasteris in turn retained The Wood Group, a power plant design/build firm, to estimate the capital costs of a new entry unit on the same basis as if they had been asked to submit a competitive bid for the turnkey development of such a project. Again, PJM gave Mr. Pasteris no indication of any desired result, and asked only for the most reasonable and accurate estimate he could provide.

The results of their analyses are documented in the initial and supplemental affidavits they submitted in this case, and are reflected in the RPM proposal in the August 31 Filing. Their detailed, independent analyses provide ample support for that filing and show that the VRR Curve and its parameters are reasonable. No other party has provided the same level of support for any of their suggested alternatives. Professor Hobbs' comprehensive analysis, in particular, is to be preferred over ad hoc predictions by other consultants about the likely effects of one curve or another under a single set of assumptions. RPM has no track record, and the Commission should be skeptical of any expert that claims to predict with any degree of assurance how market participants will respond in the RPM auctions. Therefore, the best approach, and the best available evidence on this record, is to devise reasonably representative dynamic economic simulations; run them repeatedly under randomly varying conditions; vary all of the key input assumptions across a reasonable range of possibilities; and look for consistent patterns in the results. That is what PJM has done, and it has resulted in the best-supported proposal in this proceeding.

Moreover, the results of this analytic process are not to be set in stone. The filed RPM proposal commits PJM to review with stakeholders the VRR Curve shape and key parameters within three years after implementation, based on an assessment of the market's ability to invest in new capacity and meet applicable reliability requirements. In short, dynamic models and independent estimates provide a reasonable basis for RPM's initial implementation in the absence of experience, but the results of those models and estimates should be adjusted as necessary after PJM and the stakeholders gain experience with the RPM auctions and their results.

With this background, PJM addresses each of the questions the Commission posed concerning the VRR curve and its parameters.

A. Should the Curve Be Based on the Cost of New Entry or on Other Measures, Such as the Value to Customers of Alternative Levels of Capacity?

The curve should be based on the cost of new entry by a generation unit that is representative of units that are likely to be added to provide incremental capacity. That is the same basis on which the current capacity deficiency charge is set in PJM.[62] That also is consistent with the capacity constructs approved for both the New York ISO and ISO-New England.[63] Moreover, as discussed above in Section I.C.3, the VRR Curve should be designed with the same reliability objective as today, i.e., to fall below the established IRM only on rare occasions.

As part of its review of alternatives for the VRR Curve, PJM developed a curve "based upon an approximation of how the expected value of lost load VOLL (also called unserved demand) changes when average reserve margins diverge from PJM's target reserve margin."[64] As Professor Hobbs explained, "[i]nstead of looking at the cost of an increment of additional capacity, this VOLL-based curve attempts to approximate the value to the consumer of an increment of unserved load."[65]

The VOLL curve performed very poorly in comparison to the selected VRR curve. The VOLL curve produced forecast reserves that met or exceeded the target IRM in only 54% of years, compared to 98% for the selected curve.[66] Moreover, consumer costs were higher with the VOLL curve, and had a much higher standard deviation, indicating both higher costs and more volatile cost swings, compared to the selected VRR

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62 Pennsylvania-New Jersey-Maryland Interconnection, 81 FERC ¶ 61,257, at 61,276 n.197 (1997)

63 See N.Y. Indep. Sys. Operator, Inc., 103 FERC ¶ 61,201, at P.53 (2003); Devon Power, LLC, 115 FERC P 61,340, at P. 132 (2006).

64 August 31 Filing, Tab H, Affidavit of Professor Benjamin F. Hobbs ("Hobbs Initial Aff.") at 33, ll.19-21.

65 Id. at 33-34.

66 Hobbs Initial Aff. at 36, Table 1.

curve. Id. The VOLL curve's poor relative showing continued in all of the sensitivity analyses, when Professor Hobbs varied his key input assumptions.[67]

PJM is not aware of any other proposed alternative curve that is not based on some measure of the cost of new entry. However, at the Technical Conference, Mr. Choueiki representing the staff of the Ohio PUC raised questions about whether the cost of new entry should be based on transmission or demand solutions, rather than on the costs of a new peaking unit.[68] These observations confuse the CONE parameter with the distinct question of the integration of generation, transmission, and demand response solutions in RPM. RPM permits competition to meet reliability requirements by all types of generation units, by demand response resources, and by participant-funded transmission projects. Basing the VRR curve on an estimate of new entry by a peaking unit does not preclude competitive offers from other units; it simply sets as a starting point in the curve's design the net capital costs of the type of unit that will be required to serve incremental capacity needs if no other solution comes forward.[69] Other types of resources will clear to the extent they submit more competitive offers, and all types of resources will benefit from a more stable capacity revenue stream.[70] Moreover, basing the curve on an estimate of the costs of new entry by a demand resource or transmission upgrade would raise numerous difficult questions about which of the many different

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67 Compare id. at 53, Table 5 with 57, Table 9.

68 Tr. 77-78.

69 Tr. 78-79 (Mr. Ott, PJM).

70 Tr. 139-40.

types of demand resources or transmission upgrades to use as the basis for the CONE estimate in a generally applicable VRR curve.[71]

B. What is the Cost of New Entry?

Mr. Pasteris, based on the Wood Group's estimates and his own project development experience, estimated the cost of new entry for three locations in PJM, i.e., New Jersey, Maryland, and Illinois, as \$466.04/kW, \$471.67/kW, and \$475.30/kW, respectively.[72] PJM reflected these figures in its RPM filing.

Mr. Pasteris supported his conclusions with a detailed report submitted with PJM's initial RPM filing.[73] His methodology, assumptions, and line item cost estimates all were detailed in that report. As Mr. Pasteris summarized at the Technical Confernce, the basis of the cost estimate was "going to a company in 2004 that[,] if any of the generators ask[ed] them to deliver the cost of this particular cost of new entry [plant] in 2004, would build that plant for them at these locations for that price."[74] This detailed independent assessment on its face provides a reasonable basis for the initial estimate of the cost of new entry.

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71 Mr. Hausman of CCR suggested that the curve could be based on some measure of the value of capacity to load, but he also thought that the current capacity construct met that standard. Tr. 29:17-23 and 31:22 to 32:2. As the Commission already has found that capacity construct unjust and unreasonable, Mr. Hausman's comments on that point do not warrant further consideration in the technical conference proceedings.

72 May 30, 2006 Supplemental Affidavit of Raymond M. Pasteris on Behalf of PJM Interconnection, L.L.C. on Technical Conference Issues ("Pasteris Supp. Aff.") at 1.

73 August 31 Filing, Tab I, Affidavit of Raymond M. Pasteris ("Pasteris Initial Aff.").

74 Tr. 52:18-22.

No other party presented a credible alternative estimate of the cost of new entry in the PJM Region or successfully attacked any of the specific estimates or assumptions in the Pasteris/Wood Group estimate.

Mr. Parker, in his October 2005 affidavit on behalf of a group of generators interested in a higher CONE estimate, compared PJM's estimate for the PJM Region with the higher estimates Mr. Parker previously had prepared for New York, and argued that the differences between the two demonstrated that the PJM estimate is incorrect and must be raised.[75]

However, in his Supplemental Affidavit for the Technical Conference, Mr. Pasteris convincingly rebutted each of Mr. Parker's criticisms. He correctly noted that mere differences in the PJM and New York estimates did not demonstrate that the PJM estimate was wrong.[76] In fact, he showed that the principal source of the difference was in the initially higher New York estimate of the "power island," but that Mr. Parker revised that estimate dramatically downward (to a level very close to the Wood Group's estimate) after Mr. Parker rechecked the equipment quote with the manufacturer.[77] To the extent Mr. Parker had any criticisms of any specific elements of PJM's estimate, such as the property taxes or project development costs, Mr. Pasteris provided additional supporting details in his Supplemental Affidavit to show the reasonableness of his figures.[78] Notably, when the Commission Staff asked at the Technical Conference

75 See October 18, 2005 "Affidavit of Seth G. Parker on Behalf of Midwest Generation EME, LLC, et al." ("Parker Initial Aff.") at 2-3.

76 Pasteris Supp. Aff. at 1-2.

77 Id. at 2.

78 Id. at 2-5 & Attachment A.

whether the current inquiry really should be concerned with CONE estimates in New York,[79] Mr. Parker never responded to that question.

Mr. Parker instead switched all of his emphasis to his analysis of reactive power filings at the Commission. Mr. Pasteris had used such filings as "a bump-check" to see if the estimate he developed with the Wood Group was approximately in the same neighborhood as the capital costs shown in those filings.[80] Mr. Pasteris added to those reported costs his estimated costs for Selective Catalytic Reduction emissions control technology, turbine inlet air cooling, and dual-fuel capability (to allow an apples-to-apples comparison to his estimate which included such capabilities) and found that the resulting average cost for those plants was $450.92/kW, slightly below his estimate for the three PJM locations.[81]

Mr. Parker argues that these reactive filings provide the best real-world evidence of the cost of installing new combustion turbine plants,[82] but then inflates all of those reported capital costs by over fifty percent, based on his own dizzying array of upward adjustments.[83] He rejects plants that have a slightly different model of General Electric combustion turbine as too small, applies highly judgmental "scale" adjustments to plants that are too large, combines two plants into one and then increases their costs for

79 Tr. 45:6-11.

80 Tr. 52-53.

81 Pasteris Supp. Aff. at 3.

82 Tr. 47:1-6.

83 May 30, 2006 Technical Conference Comments of Seth G. Parker at p. 9, Table 6.

economies of scale, and inserts estimates for numerous categories of allegedly missing costs.[84]

Mr. Pasteris responded to each of these specific adjustments in his Supplemental Affidavit, but his general response to Mr. Parker's analysis is the most compelling:

> When so many adjustments are made, and they all are in the same direction, the exercise looks less like a benchmark and more like an alternative estimate, with the estimator asserting greater influence over the results than does the objective external source proposed as a benchmark.[85]

Therefore, as Mr. Pasteris states, "the conclusions Mr. Parker draws from his numerous upward adjustments to these numbers are suspect." Id.

For his part, Mr. Pasteris provided at the Technical Conference some considerably more credible "real-world" affirmation of his own estimate. As he reported, a combustion turbine project with the same generators and configuration as the assumed PJM CONE plant entered service last year at a southern Wisconsin site that is only about 100 miles from one of the three PJM Region locations for which the CONE was estimated. That plant was installed for a capital cost of $135 million.[86] When Mr. Pasteris adds costs for inlet air cooling, SCR emissions control, and dual fuel capability, the resulting cost is nearly identical to his estimate of the PJM northern Illinois CONE

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84 Id. At the Technical Conference, Mr. Parker provided additional information that some of these cost categories were omitted from some of the reactive filings (Tr.47-50), but this does not demonstrate that the costs in fact were excluded from the other plants. Moreover, it does not justify such adjustments as adding Mr. Parker's estimate of project development costs, which is much higher than the estimate Mr. Pasteris and the Wood Group prepared for their PJM Region plant estimates.

85 Pasteris Supp. Aff. at 3.

86 This reflects a downward adjustment by the Wisconsin PSC to the allowed costs to reflect the market value of the GE turbines. PJM used a similar market value for its CONE estimate.

plant, and far below the estimate prepared by Mr. Parker. Mr. Pasteris also confirmed with the sponsoring utility that the capital cost total already includes all of the cost categories that Mr. Parker claims are "missing" from the reactive filings. Attachment B to these Comments is a Follow-Up Affidavit and supporting materials from Mr. Pasteris to complete the record on this recently installed comparable combustion turbine plant.

Mr. Hausman notes that the Wisconsin plant and the recent generation projects reflected in the reactive filings generally do not include SCR emission reduction technology or dual-fuel capability and argues that such capabilities should not be included in PJM's CONE estimate.[87] Mr. Pasteris responded that developers may have been able to site their plants to avoid the need for these capabilities, but that it cannot be assumed that such flexiblity always will be available, so such costs prudently should be included in a generally applicable CONE estimate.[88] If anything, the prudent inclusion of these added capabilities in PJM's CONE estimate should negate any legitimate concern by the generator representatives that Mr. Pasteris's estimate is too low.[89]

Mr. Wallach criticized the cost levelization method used to develop the CONE estimate.[90] The basis for that method was detailed by Mr. Bowring in his affidavit submitted with PJM's initial RPM filing. As he explained, the "real levelized" and

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87 Tr.57:15-25. However, Mr. Hausman greatly overstated the cost impact of these features, and was corrected by Mr. Pasteris. Tr.58-59.

88 Tr.60.

89 See, e.g., Pre-Filed Technical Conference Comments of Mr. Stoddard on Panel 1 Issues, at 6-7 (CONE estimate should err on the high side).

90 Tr. 99-100.

"nominal levelized" approaches[91] to evaluating power generation investments are commonly used by owners and developers, and therefore "[a]n actual competitive offer by a potential entrant could reasonably be based on either method of levelizing the revenue requirements."[92] Because "[t]he net CONE calculation functions as an upper bound on the price that will be paid to new entrants in the capacity market" and "the RPM construct relies upon market forces to ensure that the offer prices of new capacity are competitive," the CONE calculation properly is based on "the nominal levelized payment stream in order to ensure that the market rules do not exclude reasonable competitive offers."[93]

At the Technical Conference, Mr. Ott made a similar point, emphasizing that this is not ratemaking, but auction design. There is no guarantee that any generator will clear the auction for twenty years, or that it will receive payments based on this CONE estimate or any revised CONE estimate in the future.[94] Competitive new entry will set the clearing price in future auctions, and that price may bear little relation to the costs of an earlier entrant that was new some years earlier. Therefore, the objective is not to set a price that on average over the life of the asset will give the investors a payment stream equal to CONE. Rather, as explained by Mr. Bowring, it is to design a VRR curve that will not deter any reasonable competitive offer, so that competition is maximized.

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91 As applied here, the real levelized method results in a cost of approximately $62,000, while the nominal levelized method results in a cost of approximately $72,000.

92 August 31 Filing, Tab G, Affidavit of Joseph E. Bowring, at 9. Mr. Pasteris confirmed at the Technical Conference that project developers view the present value revenue streams as the same under either method. Tr. 100:8-18.

93 August 31 Bowring Aff. at 9-10.

Moreover, although Mr. Wallach criticizes PJM's use of the nominal levelized costs to set CONE, the dollar difference between these two methods is embedded in Professor Hobbs' modeling analysis.[95] If the Commission removed that feature, then the expected reliability would go down, because generator profits would be reduced. For example, the reliability performance that Mr. Wallach reports from his analysis of a steeply sloped curve using Professor Hobbs' model[96] likely would be lower if his other suggestion to base CONE on real levelized costs also were adopted.

As previously noted, PJM has committed to review the parameters of the VRR curve, including CONE, no later than three years after RPM is implemented. Mr. Stoddard urged CONE to be based on the new entry clearing prices in the auction, and he pointed to a formulaic approach from the ISO-New England capacity construct settlement that automatically adjusts CONE based on such auction results.[97] However, as Mr. Ott responded, there is no need to impose a formula on the PJM Region, as RPM already includes a mechanism to review the CONE with stakeholders. Whether CONE should be adjusted, and in what way, should only be determined after the actual auction results are available for review and analysis.[98] As Mr. Ott also explained, even before three years elapse, PJM would review CONE (and other potentially relevant factors, such as possible barriers to entry) if PJM observes that new entry is not offering into the RPM auctions.[99]

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94 Tr. 100-101.

95 See Hobbs August 31 Aff. at 23.

96 See May 30, 2006 Prepared Statement of Jonathan F. Wallach, at 6-7.

97 May 30, 2006 Stoddard Pre-Filed Comments on Panel 1 Issues, at 12.

98 Tr. 82 (the transcript incorrectly ascribes Mr. Ott's remarks to Mr. Stoddard).

99 Tr. 83-84.

C. How Should Energy and Ancillary Services Market Revenues Be Estimated, and How Should They Be Used to Adjust the VRR Curve?

As summarized in Mr. Ott's Supplemental Affidavit, PJM's position is that CONE should be offset by expected energy and ancillary services revenues, which should be determined each year based on an estimate of what a representative peaking unit would have earned over the prior six years considering the energy market prices and fuel costs prevailing at each of the locations where CONE is estimated.[100] Mr. Bowring described and supported this formulaic approach to estimating net revenues in his August 31 Affidavit.[101] As Mr. Ott noted in his Supplemental Affidavit, PJM now favors the "peak-hour dispatch" convention to estimate such revenues.

Mr. Choueiki, of the Ohio PUC Staff, supported the use of multiple years of history to estimate these revenues.[102] In his October 2005 affidavit, Mr. Parker supported the approach of estimating based on historical data, but he objected to PJM's proposal to use six years, instead advocating three years.[103] At the Technical Conference, however, he acknowledged that his problem is not with the use of six years per se, but with three specific years (1999 through 2001) of the recent six years used by Mr. Bowring in his illustration of the formula.[104] As Mr. Ott explained in his Supplemental Affidavit, the estimate uses a rolling six-year average, so that each year a new year is added and an old

100 Ott Supp. Aff. at 2.

101 Bowring August 31 Affidavit at 1-8.

102 Tr. 110-111.

103 Parker Initial Aff. at 16-22.

104 Tr. 132:7-11.

year drops out.[105] Accordingly, one of the years to which Mr. Parker objects is now moot as a result of the one year delay in RPM's implementation, and the other two years he dislikes will drop off in time. But setting a precedent that one or more years should selectively be removed from that rolling-six year average, based on some parties' view that those specific years are unrepresentative, is contrary to the concept of using a Commission-approved formulaic approach to estimate those revenues.

Some parties advocated basing the offset on the actual revenues earned by a representative peaking unit during the Delivery Year. The term "actual" is used loosely here, because this approach still would require a modeling estimate of what a hypothetical unit would have earned based on the conditions during that Delivery Year.[106] This approach also has very serious disadvantages, including the virtual destruction of meaningful forward price signals for demand response customers. As explained by Mr. Ott, under this approach, the RPM auctions would clear based on gross CONE, rather than net CONE, and after the Delivery Year, "a retroactive adjustment would be made to the revenues paid to generators and payments made by LSE's to account for the actual net energy revenue offset."[107] Importantly, with this retroactive adjustment "the prices resulting from the four-year forward auctions are not final; in fact they are certain to be adjusted after the Delivery Year is completed." Id.

For a generator with capacity costs and energy costs that closely track those for the hypothetical new entry unit, this approach provides some greater certainty that they

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105 Ott Supp. Aff. at 6.

106 Tr. 127:10-15 (Mr. Ott).

107 Ott Supp. Aff. at 6. See also Tr. 127-8.

will recover total revenues approximately equal to gross CONE. For resources that do not look like that hypothetical unit, however, price uncertainty is greatly increased. Therefore, this approach is especially detrimental to entities that wish to commit Demand Response alternatives in the capacity market, and LSEs that prefer bilateral contracts. As Mr. Ott explained, "[t]he lack of a firm forward clearing price will tend to present barriers to participation for Demand Response customers because they will not have certainty on the RPM payments in advance." Id. That approach also "will prevent calculation of the exact load charges in advance of the delivery year that would inform LSEs that are attempting to make decisions in acquiring retail load or planning Interruptible Load for Reliability (ILR) contracts." Id. Moreover, "the lack of a firm forward capacity price trend may create barriers to the development of a forward bilateral market in advance of the RPM auction." Id. Given that PJM has put considerable effort into designing RPM in a way that supports and encourages both demand response and long-term bilateral contracts, these are very serious shortcomings. At the Technical Conference, Mr. Ott envisioned that this approach essentially could establish a barrier to demand response participation in the forward auctions.[108]

No party contradicted Mr. Ott's description of these adverse effects. Indeed, Mr. Parker noted that this approach also is problematic for generators that are not combustion turbine peakers.[109] Mr. Stoddard added that this proposal effectively creates a sale of capacity plus a call option on the energy whenever the price goes above the dispatch price of a peaker, and that there has been no showing of any problem in the energy

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108 Tr. 130:8-12.

109 Tr. 130:2-7.

market that requires the Commission to mandate such an arrangement.[110] If such an arrangement reduces risk and would be as attractive to generators as its supporters argue, then generators can arrange such call options on their own, with conditions tailored to their needs. There is no demonstrated need for the Commission to mandate what would, in fact, be a bundling of capacity payments with a very particular type of call option.[111]

D. What Should Be the Specific Intercepts and Slopes of the VRR Curve?

PJM's recommended VRR curve values capacity at two times CONE (less energy and ancillary service revnues) when capacity is three percentage points below the target IRM. The curve values capacity at net CONE when capacity is one percentage point above IRM. From that inflection point, the curve slopes down toward a zero value at IRM + 14%, but the sloping line is cut off, and zero value assigned, when the curve reaches IRM + 5%.[112] As detailed in Professor Hobbs' August 31 Affidavit, when compared with other possible curves in his dynamic simulations, this curve appeared to offer the best combination of reliability and least consumer cost.

Mr. Stoddard proposed that the inflection point should be moved from IRM + 1% to IRM + 2%, but his supporting analysis was misleading, and the near-term uncertainty that motivated his proposal already is addressed in RPM through an updated load forecast. Based on a static historical data model he adapted from the New England

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110 Tr. 130-31.

111 Tr. 131:8-13 (Professor Hobbs).

112 Ott Supp. Aff. at 3.

capacity proceedings, he put forth the fairly dramatic claim in his pre-conference statement that PJM's proposed curve would fall short of the IRM over 23% of the time.[113]

However, he quickly backtracked from this assertion at the Technical Conference. As he revealed, he simply assumed a much higher degree of variance (or standard deviation) in the realized reserve margins than was shown by Professor Hobbs' dynamic simulation.[114] A greater variance from the average IRM necessarily means that in more years the margin will fall below the IRM.[115] Mr. Stoddard acknowledged that his numbers are based on an after-the-fact analysis, and that the appropriate analysis would be the expectation just before the Delivery Year.[116] He has not performed that analysis, and he expects the results would be that the reserves would fall short of the IRM between 2% of the time and 10% of the time, but he does not know where the answer would be in that range.[117]

In any event, both Mr. Ott and Professor Hobbs explained that Professor Hobbs' modeling approach is consistent with RPM's design, which sets capacity commitments four years forward, but then updates the load forecast shortly before the Delivery Year and secures additional resources if needed to meet higher loads.[118] This eliminates the need to increase the IRM as Mr. Stoddard proposes.

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113 May 30, 2006 Stoddard Pre-Filed Comments on Panel 1 Issues, at 15.

114 Tr. 146-47.

115 Tr. 148:20-22 (Professor Hobbs)

116 Tr. 151:18-24.

117 Tr. 151-52.

118 Tr. 150:4-25 (Professor Hobbs) and 152-53 (Mr. Ott).

Mr. Hausman launched a broad attack on Professor Hobbs modeling efforts, but his objections were not convincing. His principal criticism is that the model assumes generation investors will respond to price signals. He asserts that they will be prevented from doing so by non-financial barriers to entry.[119] However, he provided no evidence of such barriers. Mr. Ott noted that PJM has not seen such barriers in practice, citing recent construction of important new capacity by smaller market participants.[120] Mr. Stoddard also noted that RPM results in binding commitments to build, that the Commission makes a finding that there are not barriers to entry each time it approves market-based rates, and that in a region as large as PJM, there are likely to be many available plant sites.[121] Mr.Hausman revealed his true bias when he asserted that he didn't think any capacity construct could be effective.

Mr. Wallach proposed a curve that dropped to zero at IRM + 1%. He claimed that it would achieve comparable cost and reliability performance as PJM's recommended curve, and that it would reduce near-term cost.[122] However, this was the same type of curve he had proposed previously, and Professor Hobbs fully assessed the curve in his Supplemental Affidavit(at 11-12 & Table 5). Professor Hobbs showed that the curve did not perform as well as PJM's recommended curve under the base case assumptions or any other reasonable sensitivity analyses. Mr. Wallach picked the set of assumptions that made his curve look best, and declared all alternative assumptions unreasonable. This simply underscores the value of the approach PJM has taken to evaluating possible VRR

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119 Tr. 71-72.

120 Tr. 72-73.

121 Tr. 162-164.

curves. Mr. Wallach has no more special knowledge than Professor Hobbs (or anyone else) about the levels at which future RPM auction participants actually will bid. Therefore, the best approach to evaluating alternatives is to test them under a range of assumptions about what bids participants will submit. Professor Hobbs did that, using a range of assumptions that both he and Mr. Ott showed were reasonable[123] and clearly showed that Mr. Wallach's suggested curve falls well short of PJM's recommended curve.

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122 May 30, 2006 Prepared Statement of Jonathan F. Wallach, at 5-7.

123 Tr. 203 (Mr. Ott) and 206 (Professor Hobbs).

CONCLUSION

For the foregoing reasons, PJM asks that the Commission approve PJM's proposed parameters for the VRR Curve and for the long-term fixed resource requirement alternative.

Respectfully submitted,

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Docket Nos. EL05-148-000 and
ER05-1410-000
June 22, 2006

Attachment A

Responses of Professor Hobbs
To
FERC Staff Questions

MEMO **June 7, 2006**

To: Andy Ott, PJM
From: Ben Hobbs, JHU
Re: Selected Simulation Results for use in Opt-Out Discussion

The following results are for the base case assumptions for risk aversion, entry response to profits, etc., unless otherwise noted.

I. Length of Business Cycle for Curve 4 (IRM+1%).

As shown in the below figure (last page) there are roughly 12-14 cycles per 100 year period. (Five 100 year simulations are shown), so the period is approximately 7-8 years. This is for the base case assumptions.

II. Percentage of Years in Which Four Year Ahead Reserve Margin Exceeds Threshold for Curve 4

The following is the fraction of years in Figure 1 that exceed IRM by 2% and 3%, respectively. This is calculated using weather normalized peak load four years ahead of time.

Threshold	Fraction of Years
IRM + 2%	45.8%
IRM + 3%	12.4%

III. How High Vertical Curve Needs to Be Raised to Achieve 98% Chance of IRM

Here, we consider a vertical curve (Curve 1) located at the IRM, and ask how high the maximum dollar value (maximum $/unforced MW/yr) would need to be to result in a system that achieves the IRM (four years ahead of time) with a probability of 98%.

I do this considering four sets of bids for new capacity (in $/unforced MW/yr): $0; $10,000; $25,000; and $44,000. In addition the case of $44,000/unforced MW/yr for new capacity is also considered with two bid cases for existing capacity: $0 and $20,000/unforced MW/yr.

It turns out that the simulated results are not sensitive to the height of the curve. That is, raising the curve to infinity only improves the percentage of years that the curves achieve the IRM by a couple of percent at most. So I show only the base case values.

The first three rows are the same as in the affidavit. The last two are corrected values (consistent with the correction filed in the fall of 2005; the numbers may differ by a percent or two due to rounding).

Bids (Existing/New Capacity)	Percentage of Years Achieving IRM
$0/$0	39% (goes to 43% if penalty raised to $1,250,000/MW/yr
$0/$10,000	46%
$0/$25,000	63%
$0/$44,000	92%
$20,000/$44,000	96% (goes to 97% if penalty raised to $1,250,000/MW/yr

The reason why the percentage does not improve is at least in part because the amount of entry that occurs is capped at 7% of the peak load, so an extraordinarily high profit does not necessarily result in more entry.

IV. How Far the Vertical Curve Needs to Be Shifted to the Right to Achieve 98% Chance of IRM

This is directly addressed in Table 4 of the Supplemental Affidavit of B. Hobbs (p. 10) for four sets of bids.

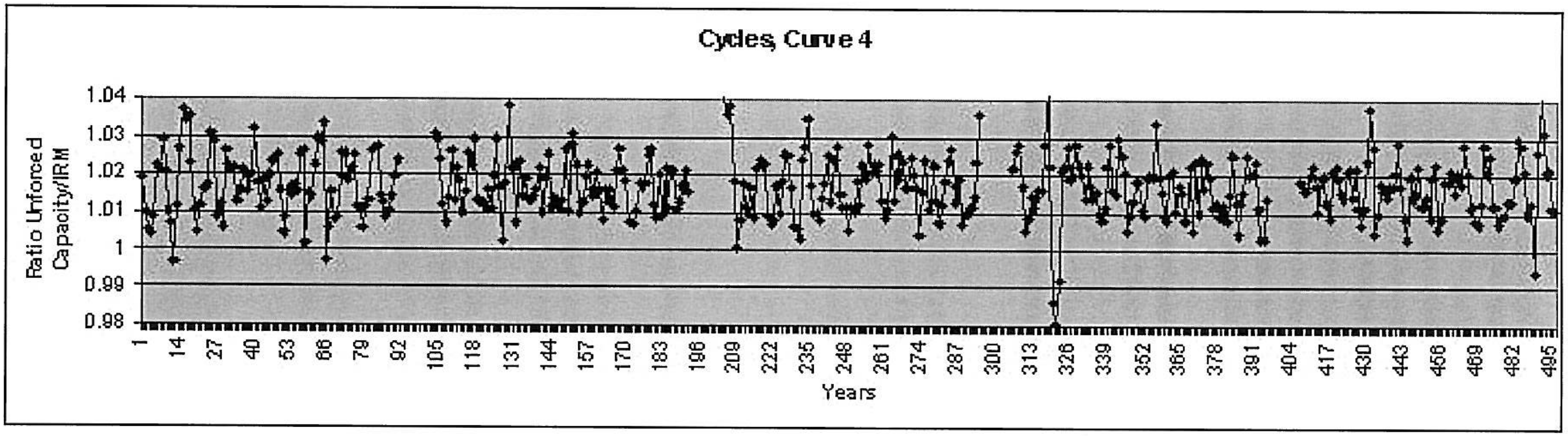

Figure 1. Cycles from Five 100-year Runs of the Model

PJM Interconnection, L.L.C.
Docket Nos. EL05-148-000 and
ER05-1410-000
June 22, 2006

Attachment B

Follow-Up Affidavit of
Raymond M. Pasteris
On Behalf Of
PJM Interconnection, L.L.C.
On Technical Conference Issues

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.	)	Docket Nos. ER05-1410-000
	)	and EL05-148-000

FOLLOW-UP AFFIDAVIT OF RAYMOND M. PASTERIS
ON BEHALF OF
PJM INTERCONNECTION, L.L.C.
ON TECHNICAL CONFERENCE ISSUES

I, Raymond M. Pasteris, being duly sworn, depose and state as follows:

I previously submitted affidavits in this proceeding on August 31, 2005 and May 30, 2006 on behalf of PJM Interconnection, L.L.C. ("PJM"), and was a panelist at the Commission's June 7, 2006 Technical Conference in this proceeding, where I addressed the estimated Cost of New Entry ("CONE") for a representative new combustion turbine plant in the PJM region.

During the Technical Conference, I mentioned the recently constructed Sheboygan Falls Energy Facility as an operating project which is essentially the PJM CONE power plant. The project incorporates two GE Frame 7FA combustion turbines in simple cycle configuration the same as the PJM CONE. The Sheboygan Falls Energy Facility design differs from the PJM CONE plant only in that it does not include turbine inlet air cooling, oil firing capability and Selective Catalytic Reduction ("SCR") for further NOx reduction beyond the controls on the combustion turbine. The plant is natural gas only with dry low NOx ("DLN") burners for NOx reduction to 9.0 PPM. SCR NOx control technology was not required by state environmental regulators for this site. Because the plant does not include turbine inlet air cooling it is rated at 300 MW versus the PJM CONE plant rating of 336.1 MW. The project began commercial operation in June of 2005.

The initial development of the Sheboygan Falls Energy Facility was undertaken by Burns and McDonnell, a power plant engineering, procurement and construction ("EPC") firm headquartered in Kansas City, MO. Burns and McDonnell identified a site outside Sheboygan Falls, WI and began developing the site for the construction of a power plant through a subsidiary company Power Ventures Generation LLC ("PVG"). PVG began the effort to secure the property, perform electric, gas and water interconnection studies and easements and obtain environmental air and water permits. PVG filed an application for a Certificate of Public Convenience and Necessity ("CPCN") with the Public Service Commission of Wisconsin ("PSCW"), which was deemed complete by the PSCW on December 11, 2003. Approximately 15 acres of a 40-acre industrial site in Sheboygan Falls was utilized for the power plant.

In January 2004 Alliant Energy Corporation signed an option to purchase from PVG the fully permitted site to build the 300 MW simple cycle natural gas fired peaking plant. PVG continued its work to obtain the necessary state and local regulatory approvals for the site and then sell the fully permitted site to Alliant Energy Generation ("AEG"), a subsidiary of Alliant Energy Corporation. Alliant Energy Corporation previously had purchased two GE Frame 7FA combustion turbines for a project in Michigan that was cancelled and was planning to install these units at Sheboygan Falls. Burns and McDonnell was retained by AEG to construct the power plant.

Construction of the plant began in July 2004 and was completed in June 2005, an 11 month construction period. Our analysis for the PJM CONE plant allowed for an 18 month construction schedule, which included the purchase and delivery of the combustion turbines. The Sheboygan Falls Energy Facility was perhaps completed in only 11 months because the combustion turbines had been pre-purchased by Alliant Energy Corporation.

The full cost of the project was $146.0 million which including the purchase of the project development from PVG, financing, interconnection, startup and commissioning and spare parts. The all inclusive nature of the capital cost was confirmed via a phone conversation with a source within Alliant Energy Corporation who was involved with the project development and construction. Alliant Energy Corporation originally requested the PSCW to include the $146.0 million project cost in rate base. However this request was reduced $11.0 million by the PSCW. A May 20, 2005 Alliant Energy Corporation press release stated the following, "The PSCW approved a 20-year lease agreement with payments based on a return on equity of 10.9 percent and a facility cost of $135 million, $11 million less than requested. The reduction reflects estimated market value of the combustion turbines versus original costs". Our capital cost estimate for the PJM CONE plant similarly used 2004 current market costs for the combustion turbines in its capital cost estimate.

Using the $135 million capital cost as the base and making capital cost adjustments to match the PJM CONE, for inlet cooling ($8.4 Million), SCR ($13.4 Million) and oil firing ($3.7 Million), the total capital cost becomes $160.5 Million or $477.5/kW. The Illinois PJM CONE, which we assumed for estimating purposes would be in a location approximately 100 miles from Sheboygan Falls, was $159.75 Million or $475.30/kW. These capital costs compare very closely.

With this recent "real world" example in Sheboygan Falls, it would be extremely difficult to expect any regulatory entity to accept the $201.5 million CONE estimate provided by Mr. Parker on Table 1 of his October 18, 2005 affidavit when compared to the $135 million capital cost for a similar project scope. This is a $66.5 million cost increase over the Sheboygan Falls Energy Facility or a nearly 50% increase in capital costs.

In a January 16, 2004 press release Alliant Energy Corporation stated "Alliant Energy expects plant construction to result in approximately 150 construction jobs with a $6 million payroll. The new generating facility will result in annual payments of $200,000 to the town and $400,000 to the county as long as the plant is operational." The combined Wisconsin property tax of $600,000 is comparable to the property taxes we estimated for each of the PJM CONE sites, i.e., $395,000 in New Jersey, $713,000 in Maryland and $333,000 in Illinois and is far below the escalated and adjusted annual property tax estimate of $4.43 million provided by Mr. Parker in Table 7 of his October 18, 2005 affidavit. Mr. Parker's property tax estimate is 7.4 times greater than that of the Sheboygan Falls Energy Facility and 13.3 times greater than the Illinois PJM CONE property tax estimate.

In addition, Alliant's reported $6 million construction labor payroll for the Sheboygan plant is in line with our estimate of construction labor for the PJM CONE plant of $9.7 million. By contrast, the updated and adjusted labor cost of $30.1 million provided by Mr. Parker in Table 3 of his October 18, 2005 testimony is five times greater than that of the Sheboygan Falls Energy Facility and three times greater than our estimate of construction labor costs for the PJM CONE plant.

This concludes my affidavit.

) Commonwealth of Pennsylvania
SS:)
) County of Bucks

AFFIDAVIT OF RAYMOND M. PASTERIS

Raymond M. Pasteris, being first duly sworn, deposes and says that he has read the foregoing "Affidavit of Raymond M. Pasteris on Behalf of PJM Interconnection, L.L.C. on Technical Conference Issues," that he is familiar with the contents thereof, and that the matters and things set forth therein are true and correct to the best of his knowledge, information and belief.

/s/ Raymond M. Pasteris
Raymond M. Pasteris

Subscribed and sworn to before me this 21 day of June, 2006.

/s/
Notary Public

My Commission expires: 7-6-2006

Notarial Seal
Paul F. Morgenthaler Jr., Notary Public
Yardley Borough, Bucks County
My Commission Expires July 6, 2006

PJM Interconnection, L.L.C.
Docket Nos. EL05-148-000 and
ER05-1410-000
June 22, 2006

Supporting Materials to Follow-Up Affidavit of Raymond M. Pasteris

Attachment A

Alliant Energy Selects Sheboygan Falls, Wisconsin as Site for 300MW Natural Gas Power Plant

Company Plans to Purchase Site From Independent Power Producer

MADISON, Wis., Jan. 16 /PRNewswire-FirstCall/ -- Alliant Energy Corp. (NYSE: LNT) announced today that its subsidiary, Alliant Energy Generation, Inc. (AEG), has assumed an option to purchase a site for a 300-megawatt (MW) simple-cycle, natural gas-fired power plant outside Sheboygan Falls, Wis. The plant is part of a comprehensive integrated resource plan announced by Alliant Energy in December 2003 to meet the electric needs of the customers of Wisconsin Power and Light (WP&L), the company's Wisconsin utility subsidiary. Subject to regulatory approval, the plant could be operational as soon as the summer of 2005.

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"Bringing this plant on-line, combined with the construction of the Rockgen and Riverside plants over the past several years will mean for the first time since the mid-1990's, WP&L will be able to meet its customers' summer electric energy needs exclusively through in-state generating facilities," said Kim Zuhlke, vice president - New Energy Resources. "We have a unique opportunity with the Sheyboygan Falls site to build a plant in a community that is open to hosting such a facility and take advantage of the significant amount of permitting work that has already been completed."

The site is currently controlled by Power Ventures Group, LLC (PVG), a subsidiary of Burns & McDonnell, an engineering and construction management firm headquartered in Kansas City, Mo. PVG announced plans to construct a natural gas plant on the site in January 2003. An application for a Certificate of Public Convenience and Necessity (CPCN) was filed with the Public Service Commission of Wisconsin (PSCW) and was deemed complete by the Commission on December 11, 2003. Approximately 15 acres of a 40-acre industrial site located at the intersection of Bridgewood Road and Highway 23 in the Town of Sheyboygan Falls would be utilized for the proposed plant. Under the proposal, PVG will continue its work to obtain the necessary state and local regulatory approvals for the site and then sell the fully permitted site to AEG. Subject to PSCW approval, AEG would construct and own the approximately $140 - 150 million plant, but WP&L would operate the plant under a long-term lease.

"As Wisconsin seeks to find ways to streamline regulatory processes, we also recognize that industry has a responsibility to do all that it can to make the process as efficient as possible," said Zuhlke. "Rather than start from square one with a new site, we are seeking to utilize the significant amount of work that has already been completed by state agencies and local government entities. We believe this is the type of cooperation that will result in a streamlined process that is timely, efficient and protective of the interests of all stakeholders."

Zuhlke said WP&L will make a separate filing with the PSCW to address the demonstrated need for the new facility. He expressed optimism that both processes can move forward concurrently, resulting in approvals that would allow for a June 2005 on-line date.

"We believe the data will show a clear need for new peaking generation in the 2005-2006 timeframe," said Zuhlke. "It is important to keep in mind that this plant is just one part of the plan we announced in December. We intend to take a diversified portfolio approach toward meeting the growing needs of our customers, which includes energy conservation, renewable energy resources, and fossil fuels while employing flexibility throughout the planning horizon."

The company has also proposed to add 100MW of wind generation, 15MW of biomass generation and 200MW of coal generation in the 2004-2010 timeframe.

The site proposal would provide for up to 450MW of generation, however only 300MW of simple-cycle generating capacity are currently planned for the site. The design and permit applications would allow the plant to meet WP&L customers' electric needs during periods of peak demand. The plant design will include the best available emissions control measures and be one of the most efficient peaking facilities serving WP&L customers. The overall plant design will be similar to the 308MW facility also owned by AEG near Neenah, Wis.

Through its SmartBurn(SM) program, the company has reduced nitrogen oxide (NOX) emissions at its Edgewater plant -- also located in Sheboygan County -- by as much as 60 percent. Zuhlke said the addition of a new, efficient natural gas-fired peaking plant combined with the continued success of the SmartBurn (SM) program would help ensure reliable electric service while minimizing the impact on the county's air quality.

"The people from PVG have done an excellent job of working with the local community to address their questions and concerns," said Zuhlke. "Wisconsin is our home and we are committed to being an excellent neighbor as the plant is constructed and as it is operated for many years to come."

Alliant Energy expects plant construction to result in approximately 150 construction jobs with a $6 million payroll. The new generating facility will result in annual payments of $200,000 to the town and $400,000 to the county for as long as the plant is operational.

"There are significant benefits for the community, the state and all our customers in bringing this new facility on-line as soon as possible," said Zuhlke. "We are excited about this unique opportunity and look forward to working with all the parties to make it happen."

Alliant Energy is an energy-services provider that serves more than three million customers worldwide. Providing its regulated customers in the Midwest with electricity and natural gas service remains the company's primary focus. Alliant Energy, headquartered in Madison, Wis., is a Fortune 1000 company traded on the New York Stock Exchange under the symbol LNT. For more information, visit the company's web site at www.alliantenergy.com .

Burns & McDonnell is an international engineering, architectural, construction and environmental services firm headquartered in Kansas City, Mo. The 106-year-old firm has more than 1,700 employee-owners in offices across the country. For more information about Burns & McDonnell, visit its website at www.burnsmcd.com .

SOURCE Alliant Energy Corp.

Public Service Commission of Wisconsin

Daniel R. Ebert, Chairperson
Robert M. Garvin, Commissioner
Mark Meyer, Commissioner

610 North Whitney Way
P.O. Box 7854
Madison, WI 53707-7854

For Immediate Release – May 5, 2005
Contact: Linda Barth
(608) 266-9600

PSC Allows WP&L to Operate New Sheboygan Power Plant

MADISON – Today the Public Service Commission of Wisconsin (PSC) approved Wisconsin Power and Light Company's (WP&L) request to lease and operate the power plant owned by Sheboygan Power LLC, both subsidiaries of Alliant Energy Corporation.

In a verbal decision, the Commission determined WP&L would need additional generation to meet customer demand this summer. The Commission allowed WP&L to lease Sheboygan Power for $135 million over the next 20 years, an amount lower than the $146 million originally requested by Sheboygan Power.

The Commission trimmed $11 million from the cost of two combustion turbines for the Sheboygan plant that were previously purchased by Alliant for a Michigan project that was terminated. The Commission also lowered the rate of return for investors from the 11.1 percent requested to 10.9 percent, saving ratepayers an additional $2 million over the life of the lease. The Commission determined it would review the financial package in five years.

Sheboygan Power plans to complete the construction of the two natural gas-fired power generators no later than the end of June 2005. The new generators will have a capacity to produce 300 megawatts. (One megawatt can generate electricity for 500 residences.) WP&L plans to operate the Sheboygan facility during times of peak electric demand.

Power Ventures Group received approval from the Commission to construct the Sheboygan facility on June 30, 2004. On July 23, 2004 the Commission approved Alliant's purchase of Sheboygan Power from Power Ventures Group for the purposes of leasing generation to WP&L. The Commission's action today set the amount for the lease payments to be made by WP&L.

The Commission will issue a written order on today's decision at a later date.

(END)

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Wisconsin Power and Light Company Receives Final Written Order on Lease Agreement for Sheboygan Falls Energy Facility

MADISON, Wis., May 20 /PRNewswire-FirstCall/ -- Wisconsin Power and Light Company (WP&L), a subsidiary of Alliant Energy Corporation (NYSE: LNT), announced that it received the final written order from the Public Service Commission of Wisconsin (PSCW) in the company's request for a lease agreement between Sheboygan Power, LLC, owners of the Sheboygan Falls Energy Facility, and WP&L.

(Logo: http://www.newscom.com/cgi-bin/prnh/20020405/LNTLOGO)

The PSCW approved a 20-year lease agreement with payments based on a return on equity of 10.9 percent and a facility cost of $135 million, $11 million less than requested. The reduction reflects estimated market value of the combustion turbines versus original cost. The PSCW determined it would also review the return on equity, the capital structure and cost of debt every five years from the date of the final decision. In addition, the PSCW confirmed the need for the facility.

"Although we are pleased to have cleared this regulatory hurdle, we have interpreted the lease generation law a bit differently than the PSCW," said Barbara J. Swan, president of WP&L. "Our interpretation of the lease agreement law is that the approval extends over the life of the lease, rather than leaving the PSCW an option to review the agreement at other points during its term. We intend to review our options to address our differences with the PSCW on this point."

Swan indicated that construction of the Sheboygan Falls Energy Facility is close to completion and is scheduled to go on line as soon as the end of this month.

Alliant Energy Corporation is an energy-services provider with subsidiaries serving more than three million customers. Providing its customers in the Midwest with regulated electricity and natural gas service remains the company's primary focus. Wisconsin Power and Light, the company's Wisconsin utility subsidiary, serves 446,000 electric and 177,000 natural gas customers. Other business platforms include the international energy market and non-regulated domestic generation. Alliant Energy, headquartered in Madison, Wis., is a Fortune 1000 company traded on the New York Stock Exchange under the symbol LNT. For more information, visit the company's Web site at http://www.alliantenergy.com .

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SOURCE  Alliant Energy Corporation; Wisconsin Power and Light Company
    -0-                           05/20/2005
    /CONTACT: Media, Nancy Kobus, +1-608-458-3187, or Investor Relations,
Becky Johnson, +1-608-458-3267, both of Alliant Energy Corporation/
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    /Web site:  http://www.alliantenergy.com /
    (LNT)

CO:  Alliant Energy Corporation; Wisconsin Power and Light Company; Public
     Service Commission of Wisconsin; Sheboygan Power, LLC
ST:  Wisconsin
IN:  OIL UTI
SU:  RLE

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Sheboygan Falls Energy Facility Begins Commercial Operation

MADISON, Wis., June 2 /PRNewswire-FirstCall/ -- Wisconsin Power and Light Company (WP&L), a subsidiary of Alliant Energy Corporation (NYSE: LNT), announced that the 300 MW, simple-cycle, natural gas-fired Sheboygan Falls Energy Facility began commercial operation today.

(Logo: http://www.newscom.com/cgi-bin/prnh/20020405/LNTLOGO)

The plant, which is expected to run primarily during periods of peak demand in the summer months, will increase reliability for WP&L customers.

Alliant Energy Generation, a subsidiary of Alliant Energy Corporation, managed construction of the facility and owns it through Sheboygan Power, LLC. In mid-May, WP&L received approval from the Public Service Commission of Wisconsin (PSCW) on its request for a lease agreement. WP&L will operate and maintain the plant.

"We appreciate the support we received from the Town of Sheboygan Falls and are pleased the facility has been completed on schedule to meet our customers' 2005 energy requirements," said Tim Bennington, vice president- generation.

Construction of the plant began in late July 2004 at a 40-acre site on Bridgewood Road just south of Highway 23 in the Town of Sheboygan Falls. The project created approximately 150 construction jobs with a $6 million payroll.

Alliant Energy Corporation is an energy-services provider with subsidiaries serving more than three million customers. Providing its customers in the Midwest with regulated electricity and natural gas service remains the company's primary focus. Wisconsin Power and Light, the company's Wisconsin utility subsidiary, serves 446,000 electric and 177,000 natural gas customers. Other business platforms include the international energy market and non-regulated domestic generation. Alliant Energy, headquartered in Madison, Wis., is a Fortune 1000 company traded on the New York Stock Exchange under the symbol LNT. For more information, visit the company's Web site at http://www.alliantenergy.com .

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SOURCE  Alliant Energy Corporation
    -0-                              06/02/2005
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Sheboygan Power, LLC Completes $70 Million Private Placement Offering

MADISON, Wis., July 1 /PRNewswire-FirstCall/ -- Sheboygan Power, LLC, a subsidiary of Alliant Energy Generation, Inc. (AEG) announced today that it completed a private placement offering of $70 million of senior secured notes. AEG is a subsidiary of Alliant Energy Resources, Inc., the parent company of Alliant Energy Corporation's (NYSE: LNT) non-regulated businesses. The senior notes have an interest rate of 5.06% and will be due 2025.

(Logo: http://www.newscom.com/cgi-bin/prnh/20020405/LNTLOGO)

Sheboygan Power, LLC will use the net proceeds to repay a portion of AEG's investment in connection with the development, site acquisition and construction of the Sheboygan Falls Energy Facility.

Wisconsin Power and Light Company (WP&L), a subsidiary of Alliant Energy Corporation, signed a 20-year lease agreement with Sheboygan Power, LLC in which it is responsible for all of the maintenance, operation and all fuel for the Sheboygan Falls Energy Facility. Per the terms of the lease, WP&L has exclusive rights to the generated output of the 300 MW simple-cycle, natural gas-fired facility. The plant is expected to run primarily during periods of peak demand in the summer months.

ABN AMRO acted as placement agent for the offering.

Alliant Energy Corporation is an energy-services provider with subsidiaries serving more than three million customers. Providing its customers in the Midwest with regulated electricity and natural gas service remains the company's primary focus. Alliant Energy's utility subsidiaries, Wisconsin Power and Light and Interstate Power and Light, serve 966,000 electric and 409,000 natural gas customers. Other key business platforms include the international energy market and non-regulated domestic generation. Alliant Energy, headquartered in Madison, Wis., is a Fortune 1000 company traded on the New York Stock Exchange under the symbol LNT. For more information, visit the company's Web site at http://www.alliantenergy.com .

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SOURCE  Alliant Energy Corporation
    -0-                           07/01/2005
    /CONTACT: Media, Scott R. Smith, +1-608-458-3924, or Investor Relations,
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    /Web site:  http://www.alliantenergy.com /
    (LNT)
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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 22nd day of June, 2006.

Paul Flynn

Paul M. Flynn
WRIGHT & TALISMAN, P.C.
1200 G Street, N.W., Suite 600
Washington, D.C. 20005
(202) 393-1200

Of Counsel for
PJM Interconnection, L.L.C.

Submission Contents