BEFORE THE FLORIDA
PUBLIC SERVICE COMMISSION

DOCKET NO. 040206-EI
FLORIDA POWER & LIGHT COMPANY

IN RE: FLORIDA POWER & LIGHT COMPANY'S
PETITION TO DETERMINE NEED FOR
TURKEY POINT UNIT 5
ELECTRICAL POWER PLANT

DIRECT TESTIMONY & EXHIBIT OF:

MORAY P. DEWHURST

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

DIRECT TESTIMONY OF MORAY P. DEWHURST

DOCKET NO. _______ - EI

MARCH 8, 2004

Q. Please state your name and business address.

A. Moray P. Dewhurst, 700 Universe Boulevard, Juno Beach, Florida 33408.

Q. What is your employment capacity?

A. I serve as Senior Vice President of Finance and Chief Financial Officer of Florida Power & Light Company (FPL or the Company).

Q. Please describe your educational and professional background and experience.

A. I have a bachelor's degree in Naval Architecture from MIT and a master's degree in Management, with a concentration in finance, from MIT's Sloan School of Management. I have approximately twenty years of experience consulting to Fortune 500 and equivalent companies in many different industries on matters of corporate and business strategy. Much of my work has involved financial strategy and financial re-structuring. I was appointed to my present position in July of 2001.

Q. What is the purpose and scope of your testimony?

A. My testimony addresses two main subjects relevant to FPL's Request for Proposals issued August 25, 2003 (RFP) and the selection of FPL's Turkey Point combined cycle option as the most cost effective project to meet resource needs in 2007. First, I describe the state of the independent power industry generally, and the need to ensure that proposers meet certain minimum standards of financial viability. I also discuss the importance of a potential supplier being willing and able to make the necessary business commitments to ensure that a proposed plant will be completed in a timely manner and operated over the term of the agreement in accordance with the supplier's original promises. I explain how these factors were taken into consideration in the RFP process.

Second, my testimony supports and supplements the testimony of Dr. Avera regarding: (a) the propriety of assigning an equity adjustment to the costs of non-FPL bids submitted in response to FPL's RFP when comparing those bids to FPL's self-build option; (b) the methodology employed in computing the amount of debt equivalent added to the Company's balance sheet; and (c) the assumptions underlying the amounts computed.

Q. Are you sponsoring any sections in the Need Study Document?

A. Yes. I am sponsoring the Financial and Economic Data included in Section V and Appendix G, Financial and Economic Assumptions, and co-sponsoring Appendix C-5.

Q. Are you sponsoring an exhibit?

A. Yes, I am sponsoring Exhibit No.___, Document No. MPD-1, which consists of Standard and Poor's (S&P) article: *Research: Energy Merchant Debt Prospects: When "Worst-Case" Scenarios Become the "Base Case"*, February 2, 2004.

Q. Describe the current state of the independent power producer (IPP) industry as it relates to capital markets.

A. On average, the trend in credit quality for the IPP segment of the U.S. utility industry has been negative for the past two years. However, there have been significant variations across companies. In general, companies that have over-extended and over-leveraged themselves, and/or those that have taken on excessive merchant generation or trading exposure in relation to their overall size, have seen their credit positions suffer most significantly. Companies that have taken significant exposure in many foreign markets – in particular those in Latin America – also have been negatively affected. On the other hand, companies whose investment programs have been well tailored to their available cash flow and balance sheet strength have been much less affected, as have those that have pre-emptively supported their growth plans through the issue of new equity or equity-linked securities. As a result, today there is a wide range of credit and balance sheet strength in the segment: some companies are eminently well positioned to meet the kinds of obligations required by FPL's RFP, while others are not. Given this wide range in financial conditions, it is especially important for FPL to carefully screen proposers for financial viability.

Q. Have there been significant changes in the IPP industry since FPL issued its last RFP in 2002 relative to the Martin 8 and Manatee 3 units?

A. Yes. During 2003 credit quality for the industry as a whole continued to deteriorate. During the year, there were 139 downgrades by S&P versus just eight upgrades, with some companies such as El Paso Corp., Duke Energy Corp., SEMCO Energy Inc., Aquila Inc., and Allegheny Energy Inc., experiencing multiple downward rating actions. Also, in the past year three companies have filed for bankruptcy protection. Significantly, as shown in the table below and described more fully in Exhibit No.___, Document No. MPD-1, credit ratings for twelve companies owning more than 200,000 MW of generation worldwide have fallen from generally investment grade to low non-investment grade levels. Five of these entities submitted proposals in FPL's last RFP solicitation.

Company	S & P Rating/Outlook as of January 2004	Company	S & P Rating/Outlook as of January 2004
AES	B+/Negative	El Paso	B/Negative
Allegheny	B/Negative	Mirant	D
Aquila	B/Negative	NEGT	D
Calpine	B/Negative	NRG	B+/Stable
Dynegy	B/Negative	Reliant	B/Negative
EME	B/Negative	Williams	B+/Negative

This deterioration has been the result primarily of highly leveraged investments, significant investments in international markets, and difficult market conditions in the U.S.

Liquidity has improved for the sector as a whole during 2003, as several of these companies successfully refinanced their bank facilities pushing out most of the $25 billion of debt maturing in 2003. Many of these companies have been selling selective assets (primarily power plants with associated long-term contracts and regulated pipelines) while others such as El Paso are exiting the electricity generation business completely. While cash from these sales and debt refinancings have kept some companies out of bankruptcy, debt leverage has actually increased, with $65 billion of debt maturing through the end of 2010.

Q. Were you surprised that FPL received 5 proposals from 4 IPPs in response to the RFP?

A. No. Given the financially distressed position of many of the members of the IPP industry, positions that, as I described above, have deteriorated further since FPL conducted its last solicitation in 2002, it is not surprising that FPL received 5 proposals. In fact, of the sixteen proposers who responded to FPL's Supplemental RFP in 2002, nearly all have had their ratings downgraded since May 2002. Specifically, nine now are rated below investment grade, with seven rated in the "B" category or lower by S&P and Moody's Investors Service (Moody's), with three of those in bankruptcy. Only five of the sixteen entities who submitted proposals in FPL's last solicitation in 2002 are rated as investment grade by the rating agencies. As discussed above, several companies are in the process of exiting the business, and others are actively selling assets to reduce debt levels. Consequently, I'm not surprised that fewer responses were received. Other factors discussed by Mr. Silva in his testimony also may have contributed to the number of proposal received.

Q. What concerns were presented for FPL in the RFP process as a result of the financially distressed state of many of the potential suppliers from the IPP industry?

A. Proposers' responses to the RFP represent promises of future commitments, which may or may not be met depending upon the specific circumstances of the particular proposer. Thus, it is necessary that FPL consider the reliability of each proposer's promises and its likely ability to meet its commitments. Factors such as a proposer's long-term financial viability, its operating track record, its stated or implied commitment to the business of operating generation projects, and its history of successfully delivering against commitments in prior projects are all important when making a long-term commitment to purchase power. A supplier that cannot complete construction of a plant according to the schedule agreed to, either because of operational failure or because of financial impairment, jeopardizes FPL's ability to provide power sufficient to meet customers' needs.

Similarly, a supplier must be able to maintain a strong financial profile over the life of the project. A supplier that fails to operate and maintain a project due to financial or other constraints will place FPL at risk of having to purchase replacement power on short notice and at the risk of higher prices or otherwise compromising system reliability. In addition, FPL may face increased risk of contract disputes with a financially weakened supplier. The cost of these various risks is ultimately borne by our customers, who will directly bear the costs of replacement power if the supplier does not have the financial wherewithal to correct operational problems or to pay the replacement power costs in the form of damages.

These concerns, although no different than FPL ordinarily would consider and did consider in its last RFP, obviously become increasingly important to the extent the financial condition of many prospective suppliers worsens. Consequently, FPL has taken steps in connection with its 2003 RFP commensurate with the generally weaker financial state of many entities within the IPP industry.

Q. **Given the heightened concerns you have noted above, what minimum financial standards or requirements did FPL include in the RFP and the power purchase agreement?**

A. The RFP and the power purchase agreement contemplate that the proposer possesses and maintains a minimum credit standard, and posts completion security if the proposal is for new construction. Additionally, the proposer is required to provide performance security for all proposals (new construction and existing facilities) throughout the operating period. These minimum standards are necessary to help ensure that the facilities which will provide contracted power will be constructed, completed on schedule, and operated and maintained in a manner consistent with the terms of the contract. Contract commitments alone are not sufficient to protect the customer. There must be sufficient amounts of cash on hand to pay for replacement capacity and energy, on short notice, in what could be tight supply conditions. In order for these contract provisions to have practical value and meaningful consequences, appropriate security amounts must be required of unregulated suppliers. Indeed, the ability and willingness of prospective suppliers to post the requisite security is a reasonable litmus test of their ability and willingness to follow through on their contractual commitments.

Q. Please describe FPL's use of debt rating agency ratings in assessing financial viability of potential proposers?

A. Credit assessments from the major credit rating agencies, S&P and Moody's, were used to set a minimum threshold of credit quality. While rating agency assessments have limitations and cannot be used as an absolute or sole indicator of financial viability for all purposes, I believe that for the purpose of providing a general indicator of a proposer's likely ability to meet its commitments under the RFP, they are a useful starting point. For example, it would be inappropriate to draw too fine a distinction between a company with an S&P rating of BBB+ and one with an A- rating. However, there is substantial evidence that default probabilities are correlated overall with ratings and, in particular, that default probabilities increase significantly as companies drop below the standard definitions of "investment grade."

Q. What is the minimum debt rating or financial viability standard required in the RFP?

A. FPL has specified as a Minimum Requirement that for proposals supported by newly built generation, the proposer or the guarantor of the proposer "'must possess a senior unsecured debt rating of not less than '"BBB-'" from S&P's

or "'Baa3'" from Moody's Investors Service with a "'stable outlook.'" S&P's definition of an investment grade issuer is an "...obligor who has adequate capacity to meet its financial commitments." A requirement that a proposer or guarantor of a proposer of newly built generation have, at a minimum, a BBB- S&P rating or a Baa3 Moody's rating helps ensure that the proposer will be able to obtain financing for the project and that cash flows will be available for ongoing maintenance of the project. The credit rating level chosen by FPL was the maximum level of risk to which FPL felt its customers should be exposed for an undertaking as significant as the financing and construction of a power plant. Based on Moody's annual study of default & recovery rates of corporate bond issuers, entities rated below investment grade have a historical five-year default rate of approximately 22 percent, substantially higher than the average default rate for higher rated entities. Such entities have low investment ratings because they reflect high risks to their investors and to counter-parties.

Q. How does FPL know that a supplier who is credit worthy today will be so 6 months from now, or 10 years from now?

A. Financial viability and credit quality are influenced by many factors, including market conditions, strategic decisions of management, and general economic conditions. Thus, there can be no guarantee that a company that is creditworthy today necessarily will be so in the future. However, while it is impossible to predict perfectly long-term viability, it is feasible to assess a proposer's current financial position and likely near-term (2 to 3 year) future financial position and to make informed judgements as to a supplier's ability to maintain a strong financial position. This may be accomplished using both publicly stated intentions and rating agency assessments. For FPL's purposes, the 2 to 3 year assessment is very important, because it coincides with the construction period for the assets that will be needed to fill the underlying capacity need. Because we applied a minimum credit threshold in our evaluation, it is not necessary to be absolutely precise about the relative levels of creditworthiness among proposers; rather, the intent was merely to ensure that entities that do not meet the minimum definition of creditworthiness were screened out. In addition to a minimum credit threshold, additional forms of security independent of credit ratings, such as completion security (for proposals with new construction) and performance security, can also be employed to protect our customers from the cost of supplier non-performance.

Q. Please describe the Completion Security requirement.

A. To help ensure timely completion of the project, the RFP and the power purchase agreement require that completion security be provided for any proposals for newly built generation in an amount equal to no less than $188,000 per MW of committed capacity. This security provides a ready source of funds to pay for replacement power if the project were to be delayed or to fail to achieve its in-service date and provides an incentive to the proposer to complete the project on schedule.

Q. How was the amount of Completion Security determined?

A. In formulating the completion security amount, FPL took a conservative approach, attempting to balance the need to protect customers with the financial impact of a security provision on a proposer. FPL captured in the completion security calculation the estimated incremental costs customers would face if FPL had to replace the energy and the capacity to be supplied by the proposer. It was assumed that FPL would purchase capacity necessary to meet its 20 percent reserve margin requirement for two years at $5/kW per month until FPL could bring four CTs into service. The calculation also assumed that FPL would continue to purchase capacity equal to the difference between its 1,066 MW need and the amount of capacity available from the four CTs until FPL could convert the four CTs into a 4x1 combined cycle unit. From this cost, FPL netted capacity costs it would not have to pay the proposers. It then added to this incremental cost its estimated replacement energy costs over the four-year period. In making that calculation, FPL made an assumption that the four CTs would not have to be removed from service to convert them from simple cycle to combined cycle mode. The total incremental cost was calculated and then divided by the total MWs of need to obtain a per MW value. Accordingly, the amount of the completion security required varies depending upon the MW of firm capacity proposed and, thus is a ratable requirement.

Q. Please describe the Performance Security requirement.

A. The RFP and the purchase power agreement also require that each proposer provide performance security in an amount equal to no less than $95,000 per MW of committed capacity. The performance security provision is included to protect customers from a developer failing to perform as it contracts. This failure to perform could manifest in a number of forms: failure to provide the contracted MW, failure to achieve the contracted heat rate, or failure to achieve contracted availability. In each instance the result is that FPL will incur replacement power costs that would be passed on to its customers. Should an event of default occur and not be cured, performance security helps provide funds necessary for FPL to purchase replacement power or to operate the plant and avoid passing the costs on to customers. The risk of less- than-contracted performance extends for the life of the PPA, which could be as much as 25 years. Rather than require proposers to post a security that would cover the potential damages for poor performance for the life of the contract, FPL determined that one half of the completion security, which envisioned essentially a four-year computation of damages as described below, would be a reasonable performance security balance.

Q. Is the entire amount of the Completion and Performance Security required in the form of cash or a Letter of Credit?

A. No. As described in the RFP and purchase power agreement (PPA), each entity will be assigned a Supplier Credit Limit based upon their unsecured debt rating and their tangible net worth as follows:

Unsecured Debt Rating	% of Tangible Net Worth
AAA+/Aaa1 to AA-/Aa3	20%
A+/A1 to A-/A3	15%
BBB+/Baa1 to BBB-/Baa3	10%
BB+/Ba1 and below or unrated	0%

Credit worthy entities with sufficient net worth can provide as little as ten percent of completion and performance security in a liquid form, i.e., cash or Letter of Credit (LOC). For example, a proposal for 1,000 MW would have to include a commitment to maintain completion security throughout the construction period in the amount of $188 million. If the Supplier were a "BBB" rated entity with two billion dollars of tangible net worth, the Supplier Credit Limit would be $200 million. Because the Supplier Credit Limit is greater than the completion security amount, the supplier would be required to post only ten percent of the completion security in the form of cash or a LOC. The remainder may be provided in the form of a corporate guarantee, at no out-of-pocket cost to the proposer.

Q. Please summarize the purpose of these minimum requirements and explain the role of step-in rights under the PPA.

A. The three functions of financial viability (minimum debt rating), completion and performance security provisions and step-in rights work in a balanced, non-redundant fashion to protect customers. The minimum financial viability and completion security requirements apply only to proposals involving the construction of a new facility. The financial viability requirement, or minimum debt rating, is necessary to minimize the risk of bankruptcy by a proposer, an event that carries its own set of costs and consequences for the purchasing utility and its customers which may only be partially, if at all, addressed by the other security requirements and step-in rights.

Once construction is completed, completion security is cancelled and replaced with performance security to provide protection to FPL's customers throughout the life of the contract. The completion and performance security provisions provide guarantees and cash equivalents to compensate our customers for their damages resulting from lack of completion and/or performance by the Developer. These requirements also provide meaningful incentives for the proposer to perform under the PPA as promised.

Where money damages alone are not sufficient to ensure that the lights will remain on, step-in rights give FPL the right to protect customers by performing work that the proposer is unable or unwilling to do.

In short, the provisions cited protect FPL's customers by 1) reducing the risk of the developer going bankrupt after FPL and its customers agree to rely upon the developer's commitment (financial viability); 2) making sure there are funds available to compensate them for extra costs caused by the proposer's failure to meet its promises (security provisions); and 3) providing FPL the option to complete and operate the plant in the event replacement power is not available (step-in rights).

Q. How did these standards and requirements affect the results of the economic evaluation?

A. In this instance, they were not determinative on the outcome of the evaluation. Although there were proposers who did not meet the minimum requirements, as Mr. Silva explains in his testimony, FPL elected to evaluate all proposals in the interest of moving forward with the process. At the same time FPL proceeded with its economic evaluation, FPL notified proposers of the nature and extent of any non-compliance and encouraged them to make changes to bring the proposals into compliance. However, as Mr. Silva describes, the evaluation indicated that no proposer failing to meet the minimum financial requirements had a competitive bid. Therefore, the failure of bids to comply with the minimum requirements was not a dispositive factor in the ultimate decision to proceed with Turkey Point Unit 5.

Q. What is an "equity adjustment" as employed by the Company in its analysis of responses to the RFP?

A. An equity adjustment is an adjustment made in the calculation of the total cost of supply options containing purchased power obligations to reflect the fact that such obligations draw upon the debt capacity of the Company and, other things being equal, must be offset by increasing the ratio of equity in the Company's financing mix. Mechanically, an equity adjustment is the net present value of the incremental cost of equity required to rebalance the Company's capital structure (the incremental cost of equity is measured relative to the cost of debt).

Q. Why is it appropriate for the Company to include an equity adjustment as a cost for the non-FPL proposals in the comparison of those bids to the FPL self-build options?

A. The equity adjustment is a real cost to a utility and its customers of entering into a purchase power agreement. In assessing a utility's credit quality, the bond rating agencies explicitly evaluate the utility's purchase power obligations. Based on that examination, the rating agencies attribute to the utility's balance sheet as debt-equivalent a portion of the net present value of the obligations under each power purchase agreement. The effect is to increase the relative share of debt and debt-like instruments in the capital structure. Accordingly, the utility needs to increase equity in its capital structure to attain the same level of financial security and flexibility with a purchased power obligation as without. The net present value of the incremental cost of increased equity to rebalance the capital structure must be added to the net present value of the cost of purchased power options evaluated to determine the total cost to FPL.

FPL's analysis of the bids took this incremental cost of capital into account. This comparison for each option enables FPL to fairly evaluate competing proposals against one another and against FPL self-build options. Were this not done, the economic comparison of self-build and external supply options would be biased in favor of the latter, leading to higher total revenue requirements to be borne by customers over the long run.

Q. **Is the equity adjustment a one-sided adjustment as has been alleged in the past?**

A. No. FPL's Equity Adjustment serves two essential purposes. First, it places RFP proposals on an equal footing with FPL's self-build options so that the net impact of both alternatives is to preserve an incremental 55 percent equity / 45 percent debt capital structure. Second, it captures the cost to FPL of restoring its capital structure to its target 55 percent equity / 45 percent debt ratio when FPL purchases power and rating agencies impute debt to FPL's capital structure. The impact of the FPL self-build option on FPL's capital structure is captured in using an incremental capital structure of 55 percent equity / 45 percent debt. The Equity Adjustment captures the corresponding impact on FPL's capital structure of purchased power agreements. Thus, it is not a one-sided adjustment.

It is undeniable that unless some offsetting action is taken, a utility's financial position will erode as a result of the imputed-debt effects from a purchase power contract. Thus, to assess properly the costs of expansion plans containing purchase power contracts, it is necessary to include the cost of additional equity required to rebalance FPL's capital structure to account for the imputed-debt impact of such contracts. In this way, the impact of purchased power on the utility's capital structure is held neutral relative to the capital structure assumed in assessing the costs of the self-build options. To do otherwise would ignore the undisputed impact of purchased power on a utility's balance sheet, resulting in a skewed comparison of the relative costs of the self-build and purchased power options by failing to hold the utility's capital structure neutral.

Indeed, it is the <u>failure</u> to include an equity adjustment in the evaluation that would provide a one-sided perspective: one which would be tantamount to a subsidy of purchased power. The cost to rebalance FPL's capital structure is a cost of both FPL's proposed unit and any purchase power option under consideration. It must be considered for both to make an appropriate determination of the lowest cost option for FPL's customers.

Q. **Please describe the basic methodology employed to determine the amount of imputed debt.**

A. While all of the rating agencies take off-balance sheet obligations into account when evaluating credit quality, S&P uses an approach that has both quantitative and qualitative aspects to value the debt component of off-balance sheet obligations. It involves first computing the net present value of the remaining capacity payments under the contract. A risk factor is then determined based primarily on the method of recovery of capacity payments. Once the risk factor is determined, it is then multiplied by the net present value of the remaining capacity payments to determine the amount of off-balance sheet obligation to include as debt in the capital structure of the company for purposes of analyzing credit quality.

Q. **Have there been any new developments in the way rating agencies determine the amount of imputed debt since FPL conducted its last RFP?**

A. Yes. In its last RFP, FPL employed a risk factor of 40 percent. S&P had indicated that it likely would assign the purchased power agreement a risk factor ranging from 40 to 60 percent, i.e., it would add to the Company's balance sheet between 40 and 60 percent of the net present value of the capacity payments as debt-equivalent. To be conservative and to avoid debate over which portion of this range more fairly represents the appropriate risk factor, FPL elected to use the bottom of the range, i.e., 40 percent, for purposes of its analysis.

Since FPL issued its last RFP in which it employed a risk factor of 40 percent, S&P has revised its methodology for determining the size of the risk factor. S&P previously established the risk factor based primarily on the relative likelihood that the purchaser would be required to make payments under the purchased power agreement. Under its revised approach, S&P now assigns the risk factor based predominantly on the method of recovery of purchased power costs, along with an assessment of other economic and regulatory factors. S&P now assigns utilities with PPAs included as an operating expense in base tariffs a 50 percent risk factor. However, "[f]or utilities in supportive regulatory jurisdictions with a precedent for timely and full cost recovery of fuel and purchased-power costs, a risk factor of *as low as 30% could be used.*" RFP, Appendix 2, Standard & Poor's Utilities and Perspectives, May 12, 2003, at 2-3 (emphasis added). FPL elected to use 30 percent, the lowest possible factor specified by S&P for utilities in supportive jurisdictions like Florida that have a purchase power cost recovery clause.

Q. How did the Company calculate the incremental cost of equity or "equity adjustment" for each bid in this case?

A. We estimated the amount of imputed debt based on the S&P methodology described above, using a risk factor of 30 percent. Once the imputed debt is calculated, equity would be required to rebalance the Company's capital structure (currently approximately 55 percent equity on an adjusted basis) in order to maintain comparable financial flexibility and credit quality. The equity adjustment represents the net present value of the incremental cost of the equity added to the capital structure.

The equity adjustment is then added to the net present value of the capacity payments under each contract to determine the total cost of each option. Once this is done, a meaningful comparison of the total cost of each option with FPL's self-build option can be made. The equity adjustment computations are shown in Appendix C-5 to the Need Study.

Q. Does this 30 percent risk factor consider the impact of a potential supplier's financial viability, as discussed earlier in your testimony?

A. No. The risk factor assigned by S&P represents the rating agency's assessment of the debt characteristics of a particular purchased power agreement. While this entails an examination of a variety of qualitative factors related to the underlying agreement and the extent to which the related financial risks are borne by FPL and its customers, S&P's assessment implicitly presumes that the generating facility has been placed in service and is operating under the terms of the purchased power agreement contemplated in the RFP. Thus, the risk factor does not directly address the financial viability of individual suppliers or the impact that this has on the ability of a particular proposer to meet its commitments.

Q. Has the Commission previously recognized that the use of an equity adjustment in assessing the true costs of purchased power alternatives is appropriate?

A. Yes. In Order No. PSC-01-0029-FOF-EI, the Commission found Florida Power Corporation's consideration of imputed debt based on a risk factor of 40 percent to be appropriate for purposes of comparing third party proposals to FPC's self-build option, the Hines Unit 2. The Commission also allowed consideration of imputed debt in approving FPL's Standard Offer Contract in Order No. PSC-99-1713-TRF-EG. Most recently, at its February 17, 2004 Agenda Conference, the Commission approved Staff's recommendation in Docket No. 031093-EQ to allow the inclusion of an equity adjustment in FPL's Standard Offer Contract.

Although the Commission declined to recognize the use of an equity adjustment in FPL's last need case, the Commission rejected the contention that an equity adjustment was improper. Instead, in Order No. PSC-02-1743-FOF-EI at page 20, the Commission said that "consideration of an equity adjustment is appropriate." According to the Commission in that order, "in future dockets, a case-by-case examination of the entire circumstances surrounding the evaluation of PPAs ... and the presence or absence of any mitigating factors shall be considered." Most recently, the Commission's staff has recommended approval of an equity adjustment in FPL's standard offer contract based on a 30 percent risk factor. Docket No. 031093-EQ.

For the reasons I have stated above, I believe the equity adjustment proposed by FPL in connection with its evaluation of purchased power options is necessary and appropriate.

Q. Did FPL consider the presence or absence of mitigating factors in conducting its evaluation?

A. Yes. While the S&P methodology takes a broad look at the debt equivalence of purchased power obligations, there may be other factors that may be considered as mitigating the effect of such purchased power obligations. FPL considered the mitigating effects of purchased power relative to its impact on the Company's balance sheet. As described in the RFP, Appendix C, pages 3 - 8, such mitigation stems principally from the benefits offered by the completion and performance security required in connection with a purchased power agreement.

Q. What are the mitigating effects offered by the Completion and Performance Security?

A. Completion and performance security address the risk of delivering less capacity than that which has been proposed and/or under performance relative to the agreement. With an FPL self-build option, there is some small probability that such an event might occur, and that impact would not be mitigated by FPL's contractual arrangements. If this occurred and it was determined by the FPSC that FPL was not imprudent, any incremental cost caused by such a delivery shortage or under performance might be recovered from FPL's customers. Therefore, the completion and performance security could mitigate the impact of those costs on FPL's customers.

The value that FPL assigned to the mitigation provided by a PPA is based upon estimates of the probabilities of a FPL delivery shortage and/or under performance, multiplied by the amount of completion and performance security.

Q. **How were these mitigating factors applied in the evaluation process?**

A. These factors were added as a credit to (reducing the magnitude of) the equity adjustment to obtain the mitigated equity adjustment. The direct testimony of Steve Sim describes how the mitigating factors were computed and included in the equity adjustment applied to each proposal.

Q. **Were proposers notified in advance that FPL would apply an equity adjustment and would consider mitigating factors?**

A. Yes. FPL's RFP provides an extensive explanation of the equity adjustment, its computation and use in the evaluation, and how mitigating factors would be applied in the methodology. This was included in Section IV.D, p. 29, and Appendix C of the RFP.

Q. Does this conclude your testimony?
A. Yes, at this time.

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Research:

Energy Merchant Debt Prospects: When "Worst-Case" Scenarios Become the "Base Case"

Publication date: 02-Feb-2004
Credit Analyst: Peter Rigby, New York (1) 212-438-2085

In less than 10 years, U.S. energy merchant companies have gone from the cradle to the graveside, if not the grave itself. In the past two years, well over $100 billion of energy merchant market capitalization has disappeared as almost everything that could have gone wrong with the nascent energy merchant industry did. In the past year, three companies have filed for bankruptcy. Bond spreads suggest that investors expect more of the same.

Credit ratings for 12 companies owning more than 200,000 MW of generation worldwide have fallen from investment grade (in most cases) to low noninvestment-grade levels (see table 1) (1). Only AES Corp. and Calpine Corp., whose credit ratings were never investment grade, experienced less credit erosion, but only because they had less distance to fall.

Many believe that it is too early to dismiss the energy merchants, arguing that matters have improved from a year ago when these 12 companies were struggling with almost $25 billion of debt maturing in 2003. By December 2003, that sum had fallen to about $800 million as the energy merchants with the reluctant assistance of their banks pushed many maturities out several years.

Table 1 Energy Merchant Corporate Credit Ratings Collapse (2001-2004)

	January 2004		Nov 2003		May 2001	
	Rating	Outlook	Rating	Outlook	Rating	Outlook
AES	B+	Negative	B+	Negative	BB	Positive
Allegheny	B	Negative	B	Negative	A	Stable
Aquila	B	Negative	B	Negative	BBB	Stable
Calpine	B	Negative	B	Negative	BB+	Stable
Dynegy	B	Negative	B	Negative	BBB	Stable
EME	B	Negative	B	Watch Neg	BBB-	Stable
El Paso	B	Negative	B+	Negative	BBB+	Stable
Mirant	D	-	D	-	BBB-	Stable
NEGT	D	-	D	-	BBB	Stable
NRG	B+	Stable	D	-	BBB-	Stable
Reliant	B	Negative	B	Negative	BBB+	Stable
Williams	B+	Negative	B+	Negative	BBB+	Stable

Were the well-publicized 2003 debt reschedulings wise decisions? Who can tell? What seems apparent, at least at this juncture, is that significant economic and business factors indicate that through the remainder of the decade, energy merchants could well have to struggle to remain in business. Energy merchants face nearly $65 billion of loans coming due by the end of 2010 out of a total debt burden of $125 billion--as indicated by ratings in the 'B' category or lower. Based on current data, it is unlikely that unsecured lenders to bankrupt energy merchants will see anything near par recovery, although secured lenders may, on the basis of recent bank loan ratings forecasting recovery, fare better.

Why the gloomy forecast? In short, almost every worst-case scenario that these companies and their lenders considered possible, but remote, has become its base case scenario. Business positions, always risky, have deteriorated and financial profiles are generally much worse than two years ago. The independent power industry built more generation, most of it gas-fired, than the market could possibly use. Natural gas prices, low for many years during the gas bubbles of the 1980s and 1990s, have now moved to levels that potentially threaten natural gas' status as "fuel of choice." Contrary to the assumptions of many market and feasibility studies, the retirements of older coal plants and nuclear plants did not occur, indeed, many older plants have displaced their new gas-fired combined cycle competitors. Energy marketing and trading proved to be expensive to pursue and marginally profitable--at best. And, the economy appears to need much less electricity than many expected, due, in part, to a shrinking manufacturing sector. Finally, the short, but tumultuous, history of competitive power suggests that the industry must intrinsically contend with low and risky margins, much as petroleum refining does.

Based on current data, the energy merchant sector and the credit prospects for the debt that financed the sector's growth will be subject to further downward pressure. Indeed, it is difficult at this point to construct a credible optimistic forecast.

Debt Problems Everywhere

More than a year ago, Standard & Poor's was the first to highlight the severity of the debt-refinancing problem faced by energy merchants (2). A study group of 30 companies, many with investment-grade ratings and access to the capital markets, faced over $40 billion in maturities coming due in 2003. For the 12 energy merchants listed in table 1, much of the problem has disappeared as they refinanced or extended their 2003 maturities (see chart 1). But that temporizing strategy could well have exacerbated the long-term problem by creating an even larger obligation that, sooner or later, will have to be addressed by those 12 energy merchants.

Total debt for the 12 merchants is about $125 billion, of which $65 billion comes due by end of 2010 (see chart 2), much of it within the next two to three years (3). This $65 billion includes nearly $22 billion of defaulted and accelerated debt at bankrupt National Energy & Gas Transmission (NEGT) and Mirant Corp., as well as the debt that NRG Energy Inc. had defaulted on (note that the data and charts within this article rely upon pre-bankruptcy emergence data from NRG. NRG emerged from bankruptcy in December 2003). Calpine alone, for instance, is due to meet some $3.7 billion of maturities in 2004. Reliant Resources Inc. successfully extended a multibillion dollar 2003 maturity to 2007 when about $4 billion will come due. In 2005, Allegheny Energy Inc. must repay a $1.5 billion note while El Paso Corp. has $1.6 billion and Edison Mission Energy (EME) has $1.7 billion coming due in 2004. The Williams Companies Inc. is distinguished by its proposed plan to retire a $1.4 billion obligation maturing in 2004 with cash on hand (4).

While most of the 12 companies have been selling assets (primarily contracted-for power plants and regulated pipelines) over the past two years, they still carry too much debt to be strong competitors in the volatile energy markets. While asset sales raised cash and improved near-term liquidity sufficient to keep nine of the 12 out of bankruptcy, debt levels are still excessive. In fact, as a group, leverage has actually increased, while book capitalization has declined as companies have taken write-offs (see chart 3) (5). Book capitalization numbers will likely continue to decline as the pace of write-offs accelerates, if only because values for the fleet of new combined-cycle, gas-fired plants are much less than installed costs. In November 2003, Reliant Resources, for example, announced a $1 billion write-off (6). In contrast with other members of the group, AES successfully issued about $340 million in equity earlier this year (7).

The Longevity of Power Plants

An interpretation of Michael Porter's competitive industry analysis model suggests that competitive power generation, as it has developed in the U.S., faces inherent obstacles to realizing the substantial profits whose allure drew so many companies into the sector (8). The structure of the competitive power, or merchant energy, model indicates a fiercely competitive and fragmented environment in which profit margins are painfully narrow. Unless something changes, such as an unlikely public policy shift back to vertically integrated utility structure, the competitive power industry will have to contend with low and uncertain returns. That so many investments in unregulated power generation have fared so poorly reinforces the point.

In particular, two inherent qualities of merchant energy, which include the activities of merchant generation and energy marketing and trading, suggest that the industry may be doomed to long-term mediocre performance. First, while the construction costs and the often protracted difficulties of siting and permitting of new power plants would seem to be viewed as obstacles to their wholesale development and construction, some 200,000 MW of new capacity built since 1999 indicates that these obstacles may not have been as formidable as originally believed. The lesson to be drawn is that the sector knows how to overcome the political and regulatory problems of permitting and construction financing, and regularly does so. Therefore, to paraphrase Michael Porter, the barriers to entry are low for new power generation.

The second quality of merchant energy keeping industry returns low is the near permanence of power plants. Most facilities built during the past 50 years or even longer still operate. Generating companies may disappear, either through bankruptcy or through consolidation, but their power plants remain. While plants may be mothballed, they can easily return to service if market conditions improve. Before the sector's capacity expansion, most market studies and the developers and lenders who relied on them assumed that older coal plants and nuclear power plants would be retired. They were not.

Indeed, the opposite happened. New owners acquired the older plants, invested in upgrades and retrofits and dramatically increased plant efficiencies and availabilities. In addition to the economic forces that have kept older plants in service, some regulated utilities that still own generation have persuaded regulators to allow unused power plants to stay in rate base to provide reliability and back-up in the future.

Consequently, merchant power competes in a world where new entrants can easily clear entry obstacles and their power plants rarely disappear. Such is the foundation, according to Porter, for a fragmented industry.

One of the Many Poor in a Fragmented Industry

Competing in the fragmented merchant power industry largely condemns its participants to thin and risky margins. The primary reason for this is that public policy in the U.S. prevents merchant power plant owners from owning significant or controlling market share. Therefore, the market structure forces merchant power into a "price taking" position; that is, with so many consumers and generators of electricity in the marketplace, no one company or individual can materially affect the price of electricity.

A second problem is that, in practice, the ability to transport electricity is limited. Unlike other commodities, electricity does not typically transport far from its source. Therefore, because power generation cannot always reach the most desirable markets, it tends to compete regionally instead of nationally. A negative reinforcement to this regional focus has been the lack of investment in transmission facilities in the U.S. for the past 20 years, as well as a governance structure that has on occasion restricted access to transmission and customers. Another problem pointed out by Frank Gaffney and Bob Davis of RW Beck is that many developers have built new generation away from load centers and out of sight of potential public opposition (9). While bulk capacity 735-kilovolt (kV), 500-kV, and 345-kV transmission lines may be available, the older and much smaller 230-kV and below lines that lead to population load centers create bottlenecks preventing potentially cheaper power from reaching markets. Finally, as Standard & Poor's pointed out earlier this year (10), the broad absence of market-based transmission operations constrains merchant power sales opportunities--a problem that the FERC has attempted to address with its Standardized Market Design.

Another aspect of merchant power that compares similarly with other fragmented industries is that electrons are undifferentiated from other electrons, save for one quality. Power plants closest to load centers will usually fare better economically than more distant ones because of transmission constraints. In addition, peaking power plants that can respond quickly to peak period needs can capture high prices better than intermediate or base, but the market needs comparatively few peaking plants and when it does, they run but a few hours of the year. As an aside, peaking plants provide a needed insurance function to the stability and reliability of the grid, yet it is not clear that competitive power markets have been willing to compensate peakers for their role. More importantly, however, and perhaps the best evidence that electricity as a commodity differs little from natural gas in consumers' minds, for instance, is that electricity end users generally are indifferent to who supplies their electricity. That few retail electricity customers in the U.S. have actually switched suppliers when given the opportunity is evidence of the point.

Yet still another consequence of fragmentation is that ownership of many power plants conveys few economies of scale; capital recovery and fuel expenses account for the bulk of generation costs, both of which practically tend to be outside of management's control.

Finally, as Standard & Poor's has pointed out, merchant generation (11) in some parts of the country competes against generation held in rate base by vertically integrated utilities. The resulting competitive advantage in favor of rate base-supported generation makes it difficult for merchant power to recover its capital costs, especially in the overbuilt generation market that dominates much of the U.S. Regulated generation, on the other hand, need recover only its variable costs--largely fuel--from the market, while capital recovery comes from captive ratepayers who pay a regulated tariff.

Consequently, in a market characterized by the absence of long-term contracts, energy merchants find it difficult to earn the stable returns that regulated industries earn or the high profits that industries with high entry barriers enjoy. That most energy merchants carry low credit ratings, in the 'B' category or less, exacerbates their competitive position. Interest costs are much higher for these companies than investment-grade companies. The noninvestment-grade energy merchants must also devote considerable and expensive capital to hedging and forward sales because few counterparties will extend credit to a noninvestment-grade counterparty in such a volatile sector. Credit concerns have also led energy merchants into the unusual position of being required to prepay for their fuel.

Poor Industry Fundamentals Compound Fragmentation

A destructive consequence of operating in a fragmented industry with low barriers to entry is a susceptibility to "boom-bust" cycles, not unlike the mining, chemical, and pulp and paper industries. Moreover, the lumpiness with which new generation enters the market and its longevity may threaten extended time frames at the bottom of the merchant business cycle. Now, as the merchant power industry appears to be reaching the end of a build-out period, energy merchants will likely have to confront surplus reserve margins for years to come. Should that happen, energy merchants will continue to find that poor industry fundamentals and depressed operating margins will frustrate capital recovery.

Gas spark spreads, the measure of gross operating margins between gas and electricity prices, illustrate the most observable measure of weak fundamentals (see charts 4A and 4B). For the past couple of years, against the backdrop of dramatically higher gas prices and excess capacity, spark spreads have fallen. In some parts of the country, such as the upper Midwest, the Southeast, Texas, and the Mid-Atlantic states, spark spreads, which are generally below $10 per megawatt-hour (MWh), do not even cover fixed operating costs. California is marginally better for now, with spark spreads exceeding $15 per MWh and getting as high as $25 in the forward market. What is particularly disconcerting for recovery prospects is that forward spark spreads seem to keep falling. The comparisons in charts 4A and 4B for the 12-month forward spark spreads for May 2003 and November 2003 generally indicate broadly declining gross margins (12).

Excess generation is the principal cause of low spark spreads. Until demand catches up to supply, the power markets will not pay for capacity and will tend to compensate generators only for fuel in an all energy market. How bad is the surplus capacity situation? Obviously the answer varies by region, but, depending on assumptions about retirements, plants in cold standby mode and new construction, most markets appear to have more than what a balanced, well-functioning market would need for many years. Well functioning markets are generally thought to need about 15% to 17% reserve margins to cover peak demand and forced outages, except in regions where hydroelectric power dominates. Such regions will need fossil reserve generation capacity for dry years.

Chart 5, which illustrates national net summer capacity and peak load historically and prospectively, suggests that as a whole the generation surplus in the U.S. could last until 2010 at a minimum under conservative and optimistic scenarios (see table 2) (13). Will retirements finally happen as many predict? While it is difficult to forecast with certainty, based on the performance of plant owners over the past several years and given power plants' longevity, conservatism is the more prudent course for credit analysis. Nevertheless, if retirements accelerate and construction rates slow even further, reserve margins could drop.

Table 2 Future Capacity Scenario Descriptions

Assumptions	Conservative (%)	Optimistic (%)
Retirements of current capacity, including standby	0	10
Completion of plants under construction	100	90
Completion of plants at advanced stages of development	90	80
Completion of plants at early planning states	50	50

Since 1997, peak load has grown at about 2.2% per year while capacity has grown 3.4% per year. Yet even if capacity were to hold constant at forecast 2005 levels, peak demand would not catch up until after 2010 under an aggressive 3% per year peak demand growth. While this analysis is somewhat simplified (a more robust analysis would have to consider regional differences), the trend will not likely differ that much regionally. It will take years for energy merchants to grow out of the excess reserve margin problem, if they can stay in business that long.

Declining Manufacturing Will Retard Merchant Power Recovery

It is unlikely that the U.S. economy will provide much help to the energy merchants. Over the years, there has been an assumed correlation between GDP and electricity demand. Yet, as chart 6 illustrates, any such correlation has been weakening for some time. Electricity demand in MWh since 1990 has grown at an annualized rate of 1.8% per year while GDP in real 1996 dollars has grown more rapidly, at about 3% per year (4.9% in nominal dollars). Peak demand has grown faster at about 2.2% per year, but still at a rate slower than GDP (14).

Why is electricity demand growing more slowly than GDP? First, the U.S. economy has become more efficient over the past decade or so as more energy-efficient end-users enter the market. But the more influential demand driver probably lies with the economy becoming more service-oriented as manufacturing moves offshore. As chart 7 illustrates, electricity demand per dollar of GDP has been steadily declining since 1990 at the latest. In addition, as industrial utilization of capacity has fallen since 2000, electric power demand by industry has similarly fallen (chart 8) (15). While the economy is beginning to escape from the doldrums of the past few years, it is too early to declare that industry utilization will return to 2000 levels. Certainly, recent reports that indicate that factories have seen their biggest jump in 20 years could indeed support a quicker recovery of merchant energy's fortunes. But Standard & Poor's, among others, does not expect a similar turnaround for the power sector anytime soon.

No Winning Business Model Has Emerged

Each of the 12 energy merchant companies has pursued the energy business differently. Hence, the different lines of businesses make strict comparisons difficult (see table 3). Some companies have focused almost entirely on generation, such as Calpine, EME, and NRG. Others have invested in less risky, regulated businesses, such as electricity distribution and supply or natural gas pipelines, or both. Still others own and operate oil and gas exploration and production subsidiaries and midstream natural gas liquids businesses. The one feature common to the 12 companies was their strategy of debt financed, rapid growth.

Exposure to commodity and market price risks makes merchant power and oil and gas exploration and production relatively risky enterprises. At the higher-risk end of the spectrum is merchant power with its capital intensiveness, its highly fragmented nature, and the lumpiness of the sector's capital investments, which are often mismatched to demand. Somewhat less risky is the oil and gas business. While also capital intensive, its capital investments can better match demand with its assets (e.g., depleting reserves) leaving the system more easily. At the low-risk end of the spectrum are natural gas pipelines with their monopoly-like qualities and their more limited exposure to commodity and market price risks. Almost as stable and predictable as pipelines are electric utilities, but they can also exhibit vulnerability to regulatory and political risk as illustrated by the events in California at the beginning of the decade. Finally, occupying the middle of the risk spectrum are the mid-stream operations and regulated or contract-based power. "Nonmerchant" power generation minimizes exposure to commodity and market risk by transferring that risk to a power purchaser for life of the asset, or at least for the life of the underlying debt. By contrast, the natural gas liquids midstream business is riskier because commodity volumes, which provide the basis for processing and logistics based income, can drop significantly from time to time as natural gas prices and weather patterns fluctuate.

Some companies, like AES, have largely avoided including merchant power plants in their portfolios, while others are almost completely invested in merchant plants. AES' business position, however, is not necessarily less risky because almost half of its revenues come from emerging market areas such as Latin America, Central Asia, and Africa. EME has announced the sale of its international portfolio to raise cash to retire debt. EME's asset sale should increase short-term liquidity, but will also increase the company business risk position because EME's international portfolio includes the more stable contract and regulated businesses. Mirant, and NEGT, both of whom are attempting to reorganize under Chapter 11 of the Bankruptcy Code, are unlikely to improve their risk profiles unless they can materially reduce their indebtedness. NRG, which just emerged from Chapter 11 protection, has reduced its debt load, but it business profile has changed little and it will face major refinancings at the end of the decade.

For energy merchants that are long in power generation, especially merchant generation, the market's excess capacity is likely to impede recovery. Companies such as Calpine, Dynegy Inc., EME, Mirant, NEGT, NRG, and Reliant, either built or acquired generation in some of the most overbuilt regions (see tables 4A and 4B). All 12 companies, for instance, make up about 10% of the Southeastern Electric Reliability Council's (SERC) capacity, and the SERC region may see reserve margins as high as 47% through 2007. In the Entergy Corp. region around Mississippi, Louisiana, Arkansas, and Alabama, where much of the new capacity in SERC resides, reserve capacities are closer to 80%. Calpine's largest exposure, about 6,400 MW, is to the Electric Reliability Council of Texas (ERCOT) market in Texas, which has a reserve margin that could be as high as 43% through 2007. Close behind ERCOT are Calpine's roughly 5,200 MW in the Western Electricity Coordinating Council (WECC) and 4,500 MW in SERC (16).

In contrast to Calpine, which is more geographically diverse than competitors, EME, NRG, and NEGT have particularly large concentrations in overbuilt markets. EME owns and operates just over 9,000 MW (about 75% of its U.S. 12,000-MW portfolio) in the Mid-America Interconnected Network (MAIN) region, with virtually all that capacity near Chicago. Similarly, NEGT owns about 6,400 MW and NRG owns about 6,600 MW in the Northeast Power Coordinating Council (NPCC) region, which could see reserve margins as high as 37% through 2007. NRG's (39% of its U.S. portfolio) and NEGT's (44% of its U.S. portfolio) assets in the NPCC region represent far less concentration than EME's 75% asset concentration in MAIN. NRG's portfolio has another type of concentration not revealed by table 4: almost 40% of NRG's U.S. portfolio consists of peaking plants, which can be the riskiest load to serve unless secured by long-term contract. Allegheny Energy Inc. also has a large concentration of generation in the East Central Area Reliability Coordination Agreement (ECAR) region. The concentration is perhaps less of a risk to Allegheny because ECAR is less overbuilt than other regions and Allegheny uses these primarily base load coal plants to supply its three electric utility subsidiaries.

The far right of table 4B shows Aquila Inc., Williams, and El Paso Corp. to be the smallest generators of the 12. Though their generation assets represent significant investments, their regulated businesses (Williams' and El Paso's pipeline companies and Aquila's utility) should somewhat offset the risks of their generation businesses. Recently, El Paso Corp. announced an agreement to sell about 25 U.S. power plants (net 1,850 MW) to Northern Star Generation LLC. The sale will reduce El Paso's exposure to generation but not merchant risk, as the plants are mostly contracted.

Table 4A Energy Merchant Co. U.S. Regnl Exposure--Most Overbuilt Region, Co. Cap. (MWs)

NERC Region	NERC Cap (MW)	2003-2007 Max Rsrve Mrgns (%)	Calpine	Reliant	NRG	Dynegy	Mirant	NEGT
SERC	222,970	47	4,466	853	3,734	4,005	1,190	2,710
WECC	171,667	45	5,197	4,893	1,514	1,235	3,738	2,489
ERCOT	83,795	43	6,435	871	704	1,161	623	183
SPP	54,747	43	1,529	0	667	1	0	0
MAIN	70,170	37	1,042	1,314	2,477	4,542	0	0
NPCC	72,735	37	1,489	2,761	6,622	1,706	2,900	6,414
MAAC	68,032	32	731	4,999	1,272	915	5,076	1,138
ECAR	133,367	31		3,115	24	3,034	1,330	1,349
FRCC	49,208	25	243	1,118	16	0	510	334
MAPP	35,870	25	0	0	5	0	0	0
Total	962,560		21,132	19,924	17,035	16,599	15,367	14,617

Table 4B Energy Merchant Co. U.S. Regnl Exposure–Most Overbuilt Region, Co. Cap. (MWs)									
NERC Region	NERC Cap (MW)	2003-2007 Max Rsrve Mrgns (%)	EME	Allegheny	AES	Williams	Aquila	El Paso
SERC	222,970	47	129	1,349	0	1,613	1,262	152
WECC	171,667	45	1,081	0	4,275	4,030	58	0
ERCOT	83,795	43	0	0	863	0	0	309
SPP	54,747	43	0	0	328	0	2,689	869
MAIN	70,170	37	9,070	0	0	0	1,894	0
NPCC	72,735	37	145		2,217			
MAAC	68,032	32	1,884	702	1,535	1,569	34	813
ECAR	133,367	31	40	8,947	310	538	979	596
FRCC	49,208	25	0	0	0	0	49	839
MAPP	35,870	25	0	0		0	381	0
Total	962,560		12,349	10,998	9,528	7,750	7,346	3,578

Poor Credit Fundamentals Will Worsen Recovery Prospects

By almost every measure, the 12 energy merchants exhibit surpassingly weak credit fundamentals. Given the sector's poor fundamental credit characteristics and its degree of fragmentation, and the merchants' $125 billion debt, the group individually and collectively will struggle to improve its credit measures by any significant degree.

Thus, consolidated leverage is at least 60% for each of the merchants (see chart 9) (17). Such leverage, combined with about 100,000 MW of merchant capacity in the U.S. (much of it fueled by natural gas), will very likely retard recovery prospects because of the inherent volatility of merchant power revenues. Companies such as AES and Allegheny with portfolios long in contracted-for capacity should see greater income stability, notwithstanding their currently high leverage levels and AES' risk of operating in emerging markets.

The second credit measure that points to the degree of distress for energy merchants is the funds from operations (FFO) to interest ratios (see chart 10). Most coverage levels for the 12 trailing months before June 30, 2003, are below 1.6x to 1.0x and well below the sector median of just over 3.0x to 1.0x (18). Absent any meaningful debt reduction, FFO/interest ratios may actually worsen should interest rates rise if the economy shows signs of sustained growth. The FFO/interest ratios may nevertheless worsen despite an improved economy if the energy merchants refinance at higher rates reflecting greater default risk, absent an unlikely improvement in their credit fundamentals.

Probably the most telling measure is the FFO after-interest expense-to-debt ratio (FFO/debt; see chart 11). Weak and declining FFO/debt ratios are empirically among the clearest indicators of financial distress as cash flow is declining or debt is rising, or both. Eight of the 12 companies have FFO/debt ratios of 6% or less and all are below 17%. By comparison, a solid investment-grade electric utility traditionally enjoys a FFO/debt ratio of at least 25% (19).

It goes without saying that, aside from AES' measured success this year, equity investors will likely refrain from contributing equity to the merchant energy sector until credit fundamentals improve. ROE for the entire group has uniformly fallen well below zero. Equity investors in the bankrupt companies stand to lose much, if not their entire investment. Moreover, because 10% of ratings in the 'B' category with a negative outlook historically default or withdraw from surveillance within a year (18% over two years), new equity will likely avoid this sector.

It is problematic whether private equity will invest in the sector. Private equity tends to invest in transitional companies with an identifiable end game. At present, it is unclear what the end game is for many energy merchants. Worse, a private equity investor in some merchant power plants, particularly gas plants in the most overbuilt regions, may find that additional investment is needed just to cover the carrying costs of insurance, taxes, and fixed maintenance. In addition, it is hard to conceive of a scenario where private equity could earn anywhere near the 20% to 30% return it typically seeks when so many energy merchant companies have delivered such large negative returns and when so much debt stands ahead of equity.

Finally, it should be noted that the market itself provides a measure of the difficulties the merchant energy sector confronts (see chart 12). While bond spreads do not in and of themselves measure credit risk, they may offer some perspective on the issuer's access to the capital markets and insight into the market's perception of default risk. As of early December 2003, yields to maturity spreads between comparable U.S. treasuries and the senior unsecured debt for the 12 companies generally exceed 500 basis points. Calpine ranks highest for companies not in default at over 2,000 bp. Williams and AES show spreads of about 500 bp, which compare favorably with average industrial 'B' rated entities. Lately, however, spreads even for these companies have been narrowing as funds have been pouring into the high yield market. In addition, companies with valuable hard assets, such as pipelines, may see tighter spreads in recognition that in bankruptcy, recovery prospects for hard asset companies will likely exceed those of pure generation companies. Unless lenders are significantly overcollaterized, as appears to be the current practice, recovery of defaulted merchant debt, secured or unsecured, could be low, as Standard & Poor's pointed out late last year (20).

Outlook for Energy Merchant Debt

As matters now stand, the energy merchant business model is under siege. The shared strategy of rapid and debt-funded growth premised on rapid deregulation of the U.S. electricity industry and open competition has not played out.

For many, worst-case scenarios have now become the base cases. The industry greatly overbuilt generation capacity to the point where many markets are largely energy-only markets that do not compensate for capacity (e.g., capital recovery). Deregulation not only did not spread more rapidly and widely as many anticipated, but may have actually contracted in the wake of the California power crisis and to a lesser extent, the Enron Corp. bankruptcy. Many energy merchant business models assumed that electricity transmission access would be uniformly available and that state-of-the-art generators could reach the load centers. Other business plans anticipated that vertically integrated utilities would sell generation assets en masse, so that even playing fields in the wholesale power market would develop. Finally, natural gas prices did not remain flat, or even decline, but rather they have moved up to what could be a much higher normalized price; that fundamentally changes the competitive dynamics for natural gas-fired generation in regions where it must compete with coal and nuclear.

Against this backdrop, the energy merchants must find a way to reduce their crushing debt burdens and do so fairly quickly if they are to survive. But the task promises to be formidable, even for those with "non-merchant" power. Lenders may look at upcoming maturities in light of the possibility of excess reserve margins through the decade and decide to retreat from the energy sector, especially if their overall lending portfolios improve with a strengthening economy. No one should expect that unsecured lenders will increase their exposures, particularly since so many banks have maneuvered themselves ahead into secured lending positions during the past 12 months. Few assets remain to be pledged to future refinancings and some of those that are pledged may provide little value anyway for some time to come. Hence, energy merchants will likely have to either slowly grow their way out of their debt problems through an improving economy or, failing that, look to reorganization strategies in bankruptcy to improve their financial positions.

Structurally, the nascent competitive power industry resembles other capital-intensive industries in which assets tend to remain in service for a long time and where barriers to entry are not difficult to overcome. These factors are the traditional basis for fundamentally low and uncertain returns--a situation that few energy merchant companies, their financial advisors, or their investors anticipated almost a decade ago. And therein lies the message for the energy merchant business; while competitive power fundamentals may never point to great businesses, firms in other industries can survive under similar circumstances and may even do well, but they do so under much more conservatively financed structures than many energy merchants first envisioned.

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Notes:

(1) January 2004 ratings are current.

(2) See Standard & Poor's, Spangler, Arleen, et al, Nov. 6, 2002. "Refinancing of Over $90 Billion Medium-Term Debt May Strain Power Sector and Associated Banks."

(3) Standard & Poor's analysis and U.S. Securities Exchange Commission filings.

(4) See Standard & Poor's, Nov. 20, 2003, "Summary: Williams Cos. (The)."

(5) See note 4.

(6) See Reliant Resources press release, Nov. 10, 2003. Retrieved from http:/www.reliant.com/corporate/news.

(7) See AES Corp. press release, June 23, 2003. Retrieved from http://www.aes.com.

(8) See Porter, Michael E. 1980, Competitive strategy, Free Press, 1980, pp. 3-33.

(9) See Gaffney, Frank & Davis, Bob. 2002, "Locational, Locational, Locational," Project Finance Power Report, pp. 24-28.

(10) See Standard & Poor's, Rigby, Peter, March 3, 2003. "Merchant Energy Survival Hangs on FERC's Blueprint for Market Design."

(11) See Standard & Poor's, Rigby, Peter, Nov. 13, 2002. "Is Time Running Out For U.S. Energy Merchant Companies? Part II: Recovery Prospects in Default."

(12) Standard & Poor's analysis based upon data from Platts Energy Trader and Bloomberg, May 1, 2003 through Oct. 31, 2003.

(13) This simple analysis is based upon Platts' PowerDat and Standard & Poor's defined scenarios. The analysis is not intended to be a forecast but rather to illustrate the potential magnitude of the excess capacity situation and how long it takes peak demand growth to catch up to supply. The aggregate data, of course, hides regional differences, some of which are worse and others better than indicated in this analysis.

(14) Platts PowerDat; A Guide to the National Income and Product Accounts of the United States (NIPA). Retrieved from http://www.bea.doc.gov/bea/an/nipaguid.pdf.; Table 1.1 Net Generation by Energy Source (All Sectors), EIA September 2003, retrieved from http://www.eia.doe.gov.

(15) See note 14.

(16) Analysis of energy merchant exposure to NERC regions and regional reserve margins based upon data using Platts' PowerDat and Standard & Poor's analysis. Standard & Poor's generally treats tolling contracts as generation capacity for the toller (the company that must pay for the right to dispatch the plant), even though another entity actually owns the power plant because the market risk rests with the toller. In addition, Standard & Poor's generally treats power plants that have contracts expiring within a five-year time frame as merchant plants because of the near-term exposure to market risk.

(17) Based upon Standard & Poor's credit analysis.

(18) Based upon Standard & Poor's credit analysis trailing 12-month financial data for the companies as of June 30, 2003. Note that the numbers for Allegheny Energy are based upon the company's reported year-end 2002 financials because those are the most recently available figures.

(19) See note 18.

(20) See note 10.