Ex. ______ (KLE-2)
Docket Nos. UE-920433, UE-920499 and UE-921262
Witness: Kenneth L. Elgin

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

PETITION OF PUGET SOUND POWER & LIGHT COMPANY FOR AN ORDER REGARDING THE ACCOUNTING TREATMENT OF RESIDENTIAL EXCHANGE BENEFITS	DOCKET NO. UE-920433
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PUGET SOUND POWER & LIGHT COMPANY, Respondent.	DOCKET NO. UE-920499
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PUGET SOUND POWER & LIGHT COMPANY, Respondent.	DOCKET NO. UE-921262

EXHIBIT OF

KENNETH L. ELGIN

WUTC STAFF

APRIL, 1991 ARTICLE FROM ELECTRICITY JOURNAL

Risky Business? The Case for Independents

Are there financial risks to utilities from power purchases from independent producers? The evidence is to the contrary: purchasing from independents tends to improve a utility's credit rating, not degrade it.

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I. Background

In the 1970s, the financial health of the electric utility industry began an unprecedented decline. Electric utility profits were squeezed by increasing costs of building and operating new generating plants, coupled with a reluctance on the part of utility regulators to raise rates. Many utilities began constructing projects for generation that later proved to be unneeded, as electricity demand growth slowed from an average of 7% per year before the 1973-74 oil embargo to about 3% per year subsequently.[1] Utility commissions decided that many of the plant investments initiated earlier (especially nuclear plants) were imprudent or not "used and useful" and should not be allowed to be recovered through rates. As a result, the financial health of the industry suffered: return on investment declined (compared to allowed returns), and utility bond ratings (generally accepted as one measure of financial health) dropped precipitously. (See Figure 1).

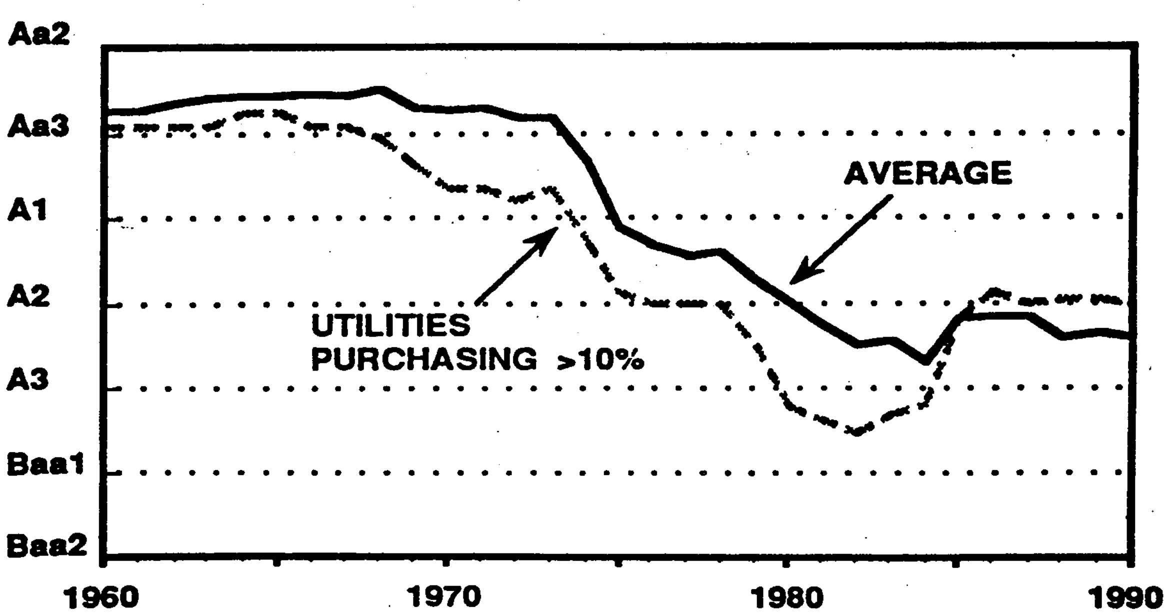
In the 1980s, however, utilities made a financial comeback. Electricity demand grew steadily in the '80s, allowing utilities to utilize much of the earlier excess capacity and to avoid building new plants. Also during the 1980s, fuel costs dropped (primarily because of a decline in oil and gas prices), and increased sales coupled with stable or even declining costs increased most utilities' profitability. As a result, as shown in Figure 1, utility bond ratings stabilized in the 1980s.

One of the contributors to keeping utilities' costs down during the 1980s has been the birth and growth of the independent power production industry.[2] Independent power generation accounted for about 80% of the new generation capacity initiated in the 1980s, while utilities initiated the remainder.[3] It has been projected that dependence on purchased power will likely continue: independents are expected to provide at least 50% of new generation capacity for the foreseeable future.[4]

In fact, the role of independents in providing new generation capacity has become so substantial over the past decade that Wall Street investors' services are beginning to take into account the potential impact of such projects on a utility's financial health when determining the utility's credit rating. Both Moody's and Standard and Poor's investor services have issued preliminary reports outlining how they might evaluate power purchased from independents as a rating consideration.[5] Both agencies suggest that under certain conditions the purchased power contracts would be treated as a fixed obligation (debt equivalent), and that they would recalculate a utility's outstanding debt and cash flow coverage ratios as a result.[6]

These reports have spawned a number of responses from the utility industry. In at least two cases,[7] utilities have argued that signing new independent contracts would cause their credit rating to be downgraded and their costs to raise capital for other projects to go up. The two utilities then argued that, as a result, their avoided cost — the price they are willing to pay for purchased power contracts — should be adjusted downward. Similarly, an article was published in *The Electricity Journal* in November 1990 by two analysts associated with National Economic Research Associates who attempted to quantify the potential impact of credit rating downgrading they suggest will result from excessive power purchases.[8] In both cases, the imputed additional cost to utilities from the financial downgrading was significant: over 1¢/kilowatt-hour (or about 20% of the price of purchased power). If this cost were legitimate, the implication would be clear: in most cases, utilities should build their own capacity rather than buy from independents. The growth in the independent power industry would come to an abrupt stop.

Figure 1: Utility Bond Ratings



How legitimate are these costs? This article will examine them from the perspective of a utility's two alternatives — constructing its own plants or purchasing power from an independent. By using the credit ratings framework for evaluating risks provided by Moody's and S&P investor services (described below),[9] we find that utilities which purchase power from independents, when compared to the option of constructing resources, improve their financial performance and raise their credit rating.

II. Risks Inherent in New Resources

A. Demand Risk

What if the utility's demand forecasts prove incorrect, and power is not needed? While this risk is real, there is really little difference to a utility between buying (in this case, purchasing from an independent) or building (constructing its own plants) from a demand risk perspective. In each case the utility acquires generation capacity over a long time period (20-30 years for purchased power contracts; more for utility construction). The utility ratepayers and shareholders therefore assume demand risk: if the capacity turns out not to be needed, the utility is still obligated to pay (earnings to bondholders and shareholders if it builds; capacity payments, at least, to sellers if it buys). Utilities have traditionally discharged this demand risk by acquiring long-term assets because of their "obligation to serve:" they need assurance that adequate and reliable capacity will be available when needed.

Utilities can mitigate demand risk by better planning and acquisition strategies. Use of least-cost planning techniques helps a utility choose the generation option that minimizes the cost of energy services delivered to its ratepayers.

The use of competitive bidding or competitive negotiations in acquiring generation through purchased power contracts helps minimize total generation costs. Many PUCs will agree to forego prudence reviews if a utility conducts a well-conceived least-cost planning and competitive acquisition process.[10]

B. Construction Risk

Construction risk was (and remains) one of the primary motivators for utilities to sign contracts with independents instead of building their own plants. In the past, utilities almost always constructed their own plants or hired an engineering firm to do the construction on a cost-plus basis: independents were not an option until the early 1980s. Postponements, delays and mismanagement often led to significant cost overruns. Regulatory commissions began to disallow "imprudent" investments, which often left utility shareholders without a return on part of their investment. Utilities remain reluctant to risk shareholders' investment dollars on construction programs that may not return a profit.

Those holding the debt of utilities implementing major construction projects also have seen the quality of their investments degrade along with the shareholders'. Indeed, in recent years the surest way for a utility to have its bonds upgraded has been to greatly lessen, or even completely renounce, future plant construction. In the three years ending with 1985, San Diego Gas & Electric saw its bonds twice upgraded from Baa to Aa as its president stated: "Regulatory uncertainty of major capital projects is behind us. SDG&E is not going to build any more large capital station generating plants. We are, however, encouraging others to help us meet future demand. . . . [W]e're encouraging cogeneration."[11] The situation was similar with Boston Edison, Consolidated Edison, and Portland General Electric, all of which announced greatly reduced construction programs. In fact, Figure 1 shows that, as a group, those utilities who pursued a strategy of purchasing power rather than building plants not only regained lost ground in average bond rating compared to other utilities, but have now surpassed the average.

A purchased power contract with an independent provides a less risky alternative to construction from the utility's point of view. The risk of utility cost overruns is eliminated by signing a long-term contract with a fixed price formula. In such an arrangement, the risk of cost overruns is borne by the independent. The independent, in turn, will sometimes pass on the construction risk to the architect/engineer firm by signing a "turnkey" fixed-price construction contract. While shifting construction risk is a major factor that differentiates independent power contracts from utility construction, there is no reason why utilities could not hedge this risk themselves in the future by signing turnkey contracts.

The fact that construction of an independent power plant is not controlled directly by the utility could add risk. Of most concern is the risk that independents with signed contracts — whose capacity is counted on by the purchasing utility to meet future load growth — will not be able to complete construction. Utilities have mitigated this risk by taking factors such as the financeability of the project, the integrity of the independent power company, and the permittability of the site into account — as well as the price of power — when choosing independent power projects. Also, most utilities specify construction standards, milestones and penalties, and the right to cancel for nonperformance in their independent power contracts. Utilities also will often require independent power producers to provide a cash security account and performance guarantees to mitigate both construction and operating risks. Finally, many utilities allow for some independent power project attrition (cancellations) in their resource plans.

Utilities benefit from shifting risk to the many firms seeking to provide new supplies.

C. Operating Risk

How well do independents operate compared to utility-built plants? The overall measure of operating reliability is a plant's availability — the percent of the time a plant is available to provide power at specified capacity and operating conditions. Factors affecting a plant's availability include fuel availability, the quality and financial strength of the owner/operator, the quality of plant construction and operations, and the terms of the purchased power contract (for example, dispatchability or performance incentives).

To date, the operating performance of the independent power industry has been remarkably strong. IPP coal plant availabilities have typically averaged 90% or above, compared to an average of 80-85% for utility-built plants.[12] Availabilities of other types of independent power plants have generally been higher than the typical utility experience.[13]

Two theories have been put forward to explain why independent power plants have higher availabilities. One is they run better because the plants are new — that only time will tell whether the initial operating successes of the industry will be sustained. The second theory is that the profit motive associated with the independent power industry, coupled with performance-based contracts, under which independents make higher profits if plant availability is high, has created a significant incentive for independents to find innovative ways to increase their plant availabilities.

D. Regulatory Risk

The historical basis for regulating electric utilities is that the service they perform is a "natural monopoly." That is, only one organization, whether it be a government or government-regulated entity like a utility, should be responsible for delivery of the service in any geographical area (service territory), and that the single organization should have no competition from other enterprises, competition being inefficient and impractical.

For years scholars and researchers have been questioning this premise regarding the generation of electricity. Certainly an argument can be made that the delivery of electricity to homes, businesses, and factories in a particular service area should be the responsibility of a single entity, to avoid needless duplication of people and capital investment. However, the generation of electricity is potentially a competitive activity. Generated electricity is a commodity — like food, automobiles, other energy products and a host of other products and services needed to sustain life.

Long before founding AES, its principals have consistently suggested that consumers would be better served by separating the true natural monopoly activities of electric utilities (transmission and distribution) from those that are competitive (generation).[14] If separated in this way, the electricity system would be similar to the relationship between highways and automobiles, where the electric wires are like the highways and the electricity itself is like the autos. The highways are government-owned or regulated (with some private toll roads), but the cars are manufactured by inde-

pendent organizations that compete for market share in a competitive market.

The United States began to move in the direction of independent generation with the passage of the Public Utilities Regulatory Policies Act (PURPA) in 1978, which gave birth to a subsequent independent power industry. Britain has just finished a dramatic reformation of its electricity generation and delivery system that completely separates the generation, transmission, and distribution parts of the business.

A comparison of the regulatory risk associated with utility construction versus purchasing power from independents also favors the purchased power option. As prudence reviews and regulatory disallowances became more common, utilities began to recognize a major advantage of acquiring capacity through independent power purchases: the fact that regulatory risk of disallowances can be substantially decreased by such purchases. PUCs are favorably predisposed toward independent power contracts because they tend to be competitive and market-based by their very nature. Since the price and terms are arrived at through competitive means, there is little need for prudence-type regulatory oversight. Recognizing the competitive nature of the acquisition process, most states pass through expenses for an independent power contract automatically in a manner similar to a fuel adjustment clause. Many states also preapprove purchased power contracts, essentially certifying that the rates and terms in the contract were arrived at competitively by finding that the contract price is less than or equal to avoided costs.

While there has been one unique instance where a regulatory commission has disallowed any payments from an independent power contract,[15] both S&P and Moody's cite this possibility as a potential regulatory risk associated with independents.[16] Such a disallowance is not only unlikely — because the competitive nature of the contract procurement process encourages favorable regulatory treatment — but is illegal under PURPA if the contract involves a "qualifying facility (QF);" PURPA makes no allowance for state regulatory oversight to disallow a contract once it has been determined that the contract price is at or below avoided costs.[17] This principle has also been affirmed in the United States Court of Appeals for non-QF power purchases.[18]

III. Financial Risk: Should IPP Contracts Be Treated As Debt?

In the early days of the 1980s, one of the first issues the independent power industry faced was how to structure steam and purchased power contracts so that the resulting obligation would be treated as an expense by the purchasing entity rather than debt. The ability of a utility to purchase power from a dedicated facility over a long-term period without incurring a debt on the utility's balance sheet was, and still is, critical to the success of independent power projects.

Debt is normally incurred by borrowing money, but it can also be incurred by entering into contractual obligations which may be considered, in substance, debt.

Utilities and independents have, for the most part, been careful to structure independent power contracts to avoid provisions that might represent "unconditional" purchase commitments (also known as "take-or-pay" contracts) on the part of the utility. Such an unconditional obligation — whether for power purchased from an independent, a neighboring utility or for the long-term supply of fuel — might well be considered debt.

To the extent that a utility incurs unconditional contract-related debt (whether for independent power contracts, or for other purchased power, or fuel supply), the effects of such contracts will usu-

ally be considered in evaluating a utility's financial strength and creditworthiness.

Partly because of this, there have been very few take-or-pay type independent power agreements. Most independent contracts include conditional provisions for payment only upon delivery and continual demonstration of the ability to deliver power to the purchasing utility. Payments usually consist of capacity (capital), energy (fuel), and operating and maintenance (O&M) components. The energy and O&M payments are clearly conditional provisions: payments are made only if kilowatt-hours are delivered. Capacity payments are conditional if the utility is required to pay only for available capacity.

To make capacity payments conditional, independent power contract provisions often will include a minimum performance standard measured against actual operating availability (for dispatchable facilities) or capacity factor (for baseload plants). If performance of the facility is below the contractually-targeted minimum, capacity payments are lowered equivalent to — or more likely, in a greater proportion than — the shortfall from the target. Contracts are generally cancellable or provide for permanent capacity "derating" to reflect less-than-minimum performance over predetermined periods. This type of contract has been described as "take-and-pay," meaning the utility pays only if the power and energy contracted is delivered.

For example, a particular power contract may be cancellable if performance has been less than a 50% capacity factor over a rolling 24-month period. Capacity payments may be reduced 2% for every 1% shortfall in weighted average capacity factor over the same 24-month period for capacity factors between 50% and 80%. Full capacity payments would be paid only if the weighted average capacity factor exceeded 80%. A capacity bonus might also be earned if the facility exceeds 80% capacity. These provisions recognize that the utility is counting on the independent facility to deliver capacity on an ongoing basis and thereby penalizes or rewards the independent for falling short or exceeding expectations and requirements.

Contractual conditions and characteristics for capacity payments such as those described in this example are clearly not unconditional purchase obligations. However, whether such capacity payments represent debt falls into an accounting "gray area," and they are not specifically dealt with under generally accepted accounting principles. However, the issue has been dealt with in a broader conceptual framework as follows:

A liability (debt) has three essential characteristics: (a) it embodies a present duty or responsibility to one or more other entities that entails settlement by probable future transfer or use of assets at a specified or determinable date, on occurence of a specified event, or on demand; (b) the duty or responsibility obligates a particular entity, leaving it little or no discretion to avoid the future sacrifice; and (c) the transaction or event obligating the entity has already happened.[19]

For the capacity payment portion of an independent power contract to be considered as debt, it must meet all three of the above criteria. The independent power contract example above can be used to illustrate the application of this conceptual framework.

With respect to criterion (a), it can most likely be argued that some future transfer (payment) is *probable*. The utility would not generally enter into a significant supply contract unless it felt that the independent supplier would most likely deliver. However, the last two criteria are not likely to be satisfied.

With respect to condition (b), the utility does have discretion: it pays only if the independent delivers. Below the 80% threshold it is not contractually

bound to continue to make full capacity payments. Below the 50% threshold it is not required to make any capacity payments and it has the discretion to terminate the contract or derate the facility. It also has the discretion — but not the obligation — to support the facility with higher-than-required payments at low performance rates if the utility (and its Commission) conclude that the contract supply, even at reduced levels, is nonetheless critical. In short, though there are contractual bounds to the utility's discretion, it is hard to conclude that it is left with "little or no discretion to avoid the future sacrifice."[20]

Finally, criterion (c) requires that the "transaction or event obligating the entity has already happened."[21] This condition is meant to distinguish between present and future obligations. A debt is not incurred until there has been an event which transfers an economic benefit. In the case of our hypothetical capacity payment structure, the debt would not be incurred until the future capacity is delivered under the contracted terms. The event of signing the supply contract (except the take-or-pay variety) does not create a present obligation or debt.

Both Standard and Poor's and Moody's differentiate between these two types of contracts. They indicate that they will treat take-and-pay contracts as an expense and take-or-pay contracts as debt.[22]

The distinction between take-and-pay and take-or-pay independent power contracts has in some analyses been either misinterpreted or ignored. For example, Perl and Luftig state that "with regard to take-and-pay contracts, S&P imputes a certain percentage of the present value of payments as debt."[23] A witness for Potomac Edison has stated that "[financial institutions] consider the portion of the contract which represents a fixed obligation to be similar to a utility's debt."[24] Yet Standard and Poor's clearly states that "S&P has viewed this performance condition (take-and-pay) as the essential element in determining whether the off-balance sheet liability is firm enough to be considered a debt equivalent."[25]

Since most independent power contracts (and perhaps all those of recent vintage) are take-and-pay, most would likely be considered off-balance sheet by the rating agencies.

IV. Financial Risk: Will Independents Hurt Utilities' Cash Flow?

A. Reduced Rate Base

A second potential financial risk to utiities from purchases from independents relates to cash flow. An argument is made that even though take-and-pay contracts do not imply a debt-like obligation, they might adversely affect a utility's cash flow by increasing its "fixed charge burden." S&P suggests that it would recalculate a utility's cash flow coverage ratio (a ratio that measures the utility's cash flow cushion available to meet its fixed obligations) to include the capacity payments of a utility's independent power contracts as a fixed obligation in this ratio, as well as interest payments.[26] Regardless of how this ratio is calculated, the relevant question is whether acquisition of generation through independents rather than construction will hurt the strength or amount of a utility's cash flow.

Some say that shareholder value could be hurt by purchasing power through "liquidation of the rate base." If a utility followed a strategy of satisfying all its generation needs through purchased power contracts, it is true that its rate base (and ultimately its total earnings and cash flow) would be lower, if all else remained equal. Yet it does not necessarily follow that earnings or cash flow *per share* would be lower. Even if a utility's rate base should decline, its cash flow would likely increase as a result of avoiding investment in new plant. The utility could retire debt, while earnings would increase as a result of lower investment and depreciation; as a result, the utility could buy back stock to maintain its target debt-equity ratio with its increased cash flow. Earnings per share would then increase with fewer shares outstanding.

A specific example set forth in Table 1 best illustrates the point.

The increased value per share arising from the decision to purchase power should at least offset any decline in rate base, resulting in share values that are at least equal to the value generated by the build option.

B. Increased Operating Leverage

Others say that independent power contracts might hurt utilities' cash flow by increasing operating leverage: "The ratio of fixed cash costs to variable cash costs could increase as the utility's operations are more dependent upon contractual obligations as opposed to owned capacity."[27]

While this might be a risk in an unregulated business, "operating leverage" should not be a problem in a regulated utility. Earnings are regulated, no matter how small they become in relation to operating expenses. Independent power expenses are no different than a utility's other expenses from a cash flow standpoint.

Utilities sometimes do suffer from poor cash flow: sometimes from mismanagement — but more often from misregulation. For example, a utility's cash flow

Table 1: Earnings Comparison of Build vs. Buy

	BUILD	BUY
Free Cash Flow	$50	$50
New Plant Cost	$50	
New Rate Base	$1050	$1000
Allowed Return	$147	$140
Repurchase Shares		$50 (4.46 shares)
Outstanding Shares	100	95.54
Earnings per Share	$1.47	$1.47

Assumed: Rate Base = $1,000; Allowed Return = 14% ($140); Earnings per Share = $1.40; Capital Structure = All Equity; Number of Shares = 100; Market Price @ 8x Earnings = $11.20

could be inadequate in the short term due to a bad sales forecast if there is no "balancing account" to recover allowed earnings in case actual sales or expenses deviate from the short-term forecast. This is, however, a regulatory problem, not a problem caused by independent power contracts.

There is also the potential risk that regulators will disallow a payment under an independent contract. This risk is essentially eliminated for QFs by obtaining regulatory pre-approval of the contract; currently, most states will pre-approve QF contracts. Pre-approval consists of a finding that the contract's price is at or below the utility's avoided cost over its full term, which is required by PURPA. Once pre-approved, the commission has no basis to disapprove future payments.[28]

V. Conclusions

As the contribution of the independent power production industry to total generation becomes significant, rating agencies are beginning to consider the effect of independent power purchases when determining a utility's credit ratings. Their framework for evaluating risk is useful. However, a fair credit evaluation should compare all aspects of the risks associated with utility construction as against those of purchasing power from independents.

When a utility needs new generation capacity, it does not have the option of doing nothing — it is obliged to serve its load and therefore must either build or buy. When utility risk is evaluated in light of this fact, it becomes clear that utilities are better off financially if they buy from independents. Table 2 makes this fact manifestly clear:

— purchased power contracts lower a utility's construction risk (which can be and often is transferred to the constructing firm),

— purchased power contracts also lower regulatory risk, since regulators are willing to pass through the cost of purchased power contracts negotiated competitively, while the risk of disallowance for the build option remains significant.

Operating risk may also be lower with independents, but it is probably still too early to tell.

Other risks — for example the risk of forecasted demand being wrong — are no different, whether a utility buys or builds.

In view of these facts, overall financing risks are lower and bond ratings will be higher with the buy option. This conclusion is supported not only by theory and analysis, but by the hard evidence of the data: to date, utilities that are following a "buy" strategy are outperforming the industry average. ■

Footnotes:

1. *See* reports covering the relevant period in U.S. ENERGY INFO. ADMIN., MONTHLY ENERGY REVIEW.

2. "Independents" are defined for the purposes of this article as all nonutility generators, including qualifying facilities (QFs), utility affiliated producers, small power producers, and non-QF independents (i.e., independent power producers with no steam host).

3. Construction on about 38,000 MW of independent power capacity was initiated in the 1980s. *See* UTIL. DATA INST., DIRECTORY OF SELECTED U.S.

TABLE 2: Risk Comparison for Build vs. Buy Option

	BUY	BUILD
Demand Risk	even	even
Construction Risk	lower	higher
Operating Risk	even to lower	even to higher
Regulatory Risk	lower	higher
FINANCIAL RISK	lower	higher

COGENERATION, SMALL POWER AND INDUSTRIAL POWER PLANTS (Apr. 1990). During the same period, utilities began construction of about 10,000 MW. *See* N. AM. ELEC. RELIABILITY COUNS., ELECTRICITY SUPPLY AND DEMAND for the 1980-89 period.

4. RCG/HAGLER, BAILLY INC., THE DEVELOPMENT OF NON-UTILITY POWER GENERATION IN THE UNITED STATES (1990); NATL. INDEP. ENERGY PROD'RS., BIDDING FOR POWER: THE EMERGENCE OF COMPETITIVE BIDDING IN ELECTRIC GENERATION ("Bidding for Power") 3 (Mar. 1990).

5. Standard and Poor's Corp., Utilities' Risks in Purchasing Power, Mar. 26, 1990 ("S&P)"; Moody's Investor Service, Purchased Power Commitments and Their Impact on Investor-Owned Electric Utility Credit Quality, Aug. 9, 1990 ("Moody's").

6. S&P, *id.* at 4; Moody's, *id.* at 6.

7. *See, e.g.*, Testimony of Regis F. Binder (Potomac Edison Co.) before the Pub. Serv. Comm. of Maryland, Case No. 8290, Nov. 13, 1990; Testimony of Delmarva Power before the Pub. Serv. Comm. of Maryland, Case No. 8201.

8. L. J. Perl and M. D. Luftig, *Financial Implications to Utilities of Third Party Power Purchases*, THE ELEC. J., Nov. 1990, at 24.

9. The actual risks described in the following sections vary greatly depending on the specific utility and independent power contract, although this paper attempts to draw generic conclusions.

10. Bidding for Power, *supra* note 4 at 36.

11. ANNUAL REPORT, SAN DIEGO GAS AND ELECTRIC (Statement of T. Page 1985).

12. From AES and other IPP industry operating data.

13. Natl. Indep. Energy Prod'rs., Reliability of Non-Utility Generation, Draft Rep. 1989, at 10-14.

14. R. W. SANT, THE LEAST COST ENERGY STRATEGY (Carnegie-Mellon U. Press 1979); R. W. SANT, et. al., EIGHT GREAT ENERGY MYTHS, (Carnegie-Mellon U. Press 1981); R. W. SANT, D. W. BAKKE, AND R. F. NAILL, CREATING ABUNDANCE (McGraw-Hill 1984).

15. The California PUC disallowed a payment by Southern California Edison Co. to its subsidiary, Mission Energy, because of self-dealing. *See, e.g.*, Energy Daily, Oct. 2, 1990. The disallowance was made because the contracting process was judged to be uncompetitive.

16. *See* S&P, *supra* note 5 at 4; Moody's, *supra* note 5 at 8.

17. *See* 18 CFR ¶292.304(b)5(d)2, which establishes that the relevant avoided cost is the avoided cost established at the time the contract is signed.

18. *See* San Diego Gas & Electric v. FERC, D.C. Cir. No. 88-1744 (June 8, 1990). SDG&E's purchased-power contract was upheld despite a drop in prices between execution of the contract and when the sale of power was to begin.

19. Financial Accounting Standards Board (FASB), Statement of Financial Concepts No. 6: Elements of Financial Statements, ¶ 36, Dec. 1985.

20. *Id.*

21. *Id.*

22. *See* S&P, *supra* note 5 at 4; Moody's, *supra* note 5 at 5.

23. Perl and Luftig, *supra* note 8 at 27.

24. Binder, *supra* note 7 at 18.

25. S&P, *supra* note 5 at 4.

26. *Id.* The new cash flow coverage ratio would be calculated as (funds from operations + interest + capacity payments)/(interest + capacity payments).

27. S&P, *supra* note 5 at 2.

28. A commission could later disapprove payments if there was evidence of fraud or mismanagement, but not because it later seems "imprudent" — e.g., actual utility costs later turn out to be lower than the IPP contracts costs.

To buy or to build? Isn't it clear?