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February 27, 2006

Via Electronic and US Mail

Public Utility Commission
Attn: Filing Center
550 Capitol St. NE #215
P.O. Box 2148
Salem OR 97308-2148

Re: In the Matter of PUBLIC UTILITY COMMISSION OF OREGON Staff's Investigation Related to Electric Utility Purchases from Qualifying Facilities.
Docket No. UM 1129

Dear Filing Center:

Enclosed please find an original and six copies of the Direct Testimony of R. Thomas Beach on behalf of Weyerhaeuser Company and the Industrial Customers of Northwest Utilities in the above-captioned docket.

Please return one file-stamped copy of the document in the self-addressed, stamped envelope provided. Thank you for your assistance.

Sincerely yours,

<u>/s/ Anna E. Studenny</u>
Anna E. Studenny

Enclosures
cc: Service List

BEFORE THE PUBLIC UTILITIES COMMISSION
OF OREGON

UM 1129 (Phase II)

In the Matter of the	)
	)
PUBLIC UTILITY COMMISSION OF OREGON	)))
Staff's Investigation Relating to Electric Utility Purchases From Qualifying Facilities.	)))

DIRECT TESTIMONY OF

R. THOMAS BEACH

ON BEHALF OF

WEYERHAEUSER COMPANY

AND THE INDUSTRIAL CUSTOMERS

OF THE NORTHWEST UTILITIES

February 27, 2006

I. INTRODUCTION AND SUMMARY

Q. PLEASE STATE FOR THE RECORD YOUR NAME, POSITION, AND BUSINESS ADDRESS.

A. My name is R. Thomas Beach. I am principal consultant with the firm Crossborder Energy. My business address is 2560 Ninth Street, Suite 316, Berkeley, California 94710.

Q. PLEASE DESCRIBE YOUR EXPERIENCE AND QUALIFICATIONS.

A. I have 25 years experience working in the natural gas and electric industries, including eight years on the staff of the California Public Utilities Commission ("CPUC") and 17 years as a private consultant serving clients with interests in the energy markets in the western U.S. My work has included significant experience on a wide range of issues concerning qualifying facilities ("QFs") under the Public Utilities Regulatory Policies Act of 1978 ("PURPA"). I have testified many times on QF issues before the state public utilities commissions in California, Oregon, and Nevada. A list of the testimony that I have filed before these commissions is included in Exhibit Weyerhaeuser-ICNU/301, which also fully describes my experience and qualifications.

Q. HAVE YOU TESTIFIED PREVIOUSLY BEFORE THIS COMMISSION IN THE UM 1129 DOCKET?

A. Yes, I have. I testified before the Commission in the Policy Phase of UM 1129, on behalf of Weyerhaeuser Company ("Weyerhaeuser").[1/]

Q. ON WHOSE BEHALF ARE YOU TESTIFYING TODAY?

A. I am appearing on behalf of Weyerhaeuser and the Industrial Customers of the Northwest Utilities ("ICNU").

Weyerhaeuser owns and operates several manufacturing facilities in Oregon with thermal requirements capable of supporting thermally-balanced combined heat and power

[1/] Weyerhaeuser/100, Beach/1-16 (Direct Testimony Phase I) (Aug. 3, 2004).

("CHP") installations, including the Albany Paper Mill in Albany, Oregon. The Albany Paper Mill is now the most modern linerboard mill in the world. The mill has its own five-mile natural gas pipeline and a biomass and natural gas fueled CHP facility of sufficient size to meet the plant's steam and electrical needs. Today, this modern facility uses a 50-50 blend of recycled and kraft fibers to produce 530,000 tons per year of containerboard and other paper products. The plant employs 315 people and operates seven days per week, 24 hours per day.

I am also testifying on behalf of ICNU. ICNU is a non-profit trade association, whose members are large industrial customers served by electric utilities throughout the Pacific Northwest, including Portland General Electric ("PGE") and PacifiCorp. ICNU strongly supports the further development of cost-effective new CHP facilities in the Northwest, including CHP QFs under PURPA.

Both Weyerhaeuser and ICNU have participated actively in the prior Policy Phase of the UM 1129 proceeding, which led to the Commission's decision in Order 05-584 ("Order No. 05-584").

Q. PLEASE DESCRIBE THE INTERESTS OF WEYERHAEUSER AND ICNU IN PHASE II OF THIS PROCEEDING?

A. In this phase of the proceeding, Weyerhaeuser and ICNU are concerned primarily with the negotiating parameters and guidelines that the Commission intends to adopt in Phase II for negotiations between the investor-owned utilities ("IOUs") and QFs that exceed the 10 MW ("megawatt") size threshold for eligibility for a standard QF contract. These include the guidelines for both "net out" contracts (also known as "simultaneous purchase and sale" contracts) and "surplus sale" contracts. The central focus of the negotiating guidelines should be the factors that may be considered in setting avoided cost prices, as set forth in the Federal Energy Regulatory Commission's ("FERC") QF rules.[2/] I also comment on: 1) certain specific contractual provisions for large QFs identified in the Order; 2) the parameters for the negotiating process; 3) whether large QFs should have the option of avoided cost prices that are indexed to natural gas prices; and 4) the issue of whether large QFs should be required to participate in a competitive bidding process. It is my understanding that issues regarding off-system QF sales will be addressed in separate testimony that is due in March; thus, my testimony does not address those issues. Each of the issues identified above is included in the list of Phase II issues that the assigned Administrative Law Judge approved in her ruling dated November 17, 2005.

Q. PLEASE BRIEFLY SUMMARIZE YOUR TESTIMONY.

A. My testimony presents the following key points and recommendations:

- Allowing QFs to choose whether to sell power to the utility under the "simultaneous purchase and sale" option or the "surplus sale" option is both consistent with avoided cost principles and reasonable for ratepayers. Under the "simultaneous purchase and sale" option, the on-site load must abide by all of the requirements of the utility sales tariff under which it receives service.
- The most important step that the Commission can take to assist negotiations between the QF and the utility is to adopt reasonable guidelines for the pricing factors included in the FERC QF regulations. These guidelines should include:
  - ➢ **Reliability.** QF contracts for firm power should provide incentives for reliable performance, through fixed dollar per kilowatt ("kW")-year capacity payments that are tied to the QF's

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2/ *See* 18 CFR §292.304[e].

achieved performance during the utility's peak period, with a reasonable allowance for forced outages. QFs should face symmetric incentives for superior performance and penalties for inadequate output. As-available or non-firm QFs should receive capacity payments only to the extent that they actually deliver power during peak periods.

- **Dispatchability** should be handled through time-differentiated on- and off-peak pricing, in recognition that CHP facilities may have little or no ability to allow the utility physically to dispatch their facilities.
- **Termination** provisions should keep ratepayers whole if a QF has received front-loaded capacity payments.
- QFs should **schedule maintenance outages** during non-peak months, with reasonable advance notice to the utility.
- QFs should have a "best efforts" obligation to deliver their contract capacity to the utility during **system emergencies**, when the integrity of the utility's system is threatened.
- There should be QF-specific **transmission or line loss studies** if a QF's location causes a substantially different impact on the utility's line losses and transmission costs than does the avoided resource.

- The small size, distributed locations, aggregate value, and resource diversity of QFs may make QF power more valuable to the utility than the costs reflected in the utility's filed avoided costs.
- The avoided costs for large QFs should not be adjusted for debt imputation. The Commission should review the debt imputation issue in the broad context of all of a utility's power purchase agreements. If debt imputation represents a real and measurable cost to the utility from its Purchased Power Agreements ("PPAs"), that cost should be reflected in the utility's filed avoided cost calculations.
- The IOUs should not be allowed to utilize additional factors to adjust their avoided costs for large QFs in negotiated contracts. Specifically, Commission guidelines should be the only factors that QFs and the IOUs can utilize to adjust avoided costs.
- A well-defined set of negotiating guidelines will benefit the utilities by increasing the likelihood that non-standard QF contract costs will be recoverable in rates.
- It is a reasonable guideline for large QF contracts to have terms of up to 20 years, with avoided cost rates to be set for the initial 15 years.
- The "firmness" of QF power supply commitments should be reflected in the payment terms for QF contracts. Firm capacity QFs should be paid capacity payments based on their achieved capacity factor during peak periods. As-available or non-firm QFs should receive capacity payments strictly on a dollar per MWh basis for power delivered during peak periods.
- With respect to the negotiation process, when the utility tenders an indicative pricing proposal or proposed PPA, the utility should state in writing how it has

modified the standard rates or standard contract, based on the Commission's adopted guidelines. The utility should modify only those areas in which it has Commission authorization to depart from the standard contract. PacifiCorp's Schedule 38 should be modified to so provide.

- Avoided cost rates for large QFs should be indexed to natural gas prices in the same manner as standard rates. Indexing to gas allows avoided cost rates to track changes in the market prices for gas and power, and promotes more stable output from CHP QFs.
- Bids from competitive solicitations should not be used to set avoided cost rates unless the utility can justify, and the Commission approves, the use of such bids as the correct measure of the utility's avoided costs. QFs should not be required to participate in utility solicitations in order to obtain long-term contracts, because utility solicitations are rarely designed to provide QFs with a meaningful opportunity to bid. In addition, the use of competitive bidding may allow utilities to avoid their obligation to purchase power from QFs at avoided costs.

II. SIMULTANEOUS PURCHASE/SALE AND SURPLUS SALE CONTRACTS

Q. PLEASE DESCRIBE IN GENERAL TERMS THE ISSUE OF WHETHER LARGE QFS SHOULD HAVE THE OPTION TO SELL POWER TO THE UTILITY ON EITHER A "SIMULTANEOUS PURCHASE AND SALE" BASIS OR A "SURPLUS SALE" BASIS. [ISSUES 8 AND 9]

A. CHP projects typically are developed at commercial or industrial sites that have a significant existing, on-site electrical load that the local utility is serving under its current tariffs. CHP projects can theoretically sell power to the utility or third parties outside of PURPA, but often experience practical difficulties and significant barriers. CHP QFs can sell power to the utility in two ways under PURPA: 1) the QF can sell its generator's entire output (net of internal auxiliary loads) to the utility at avoided cost prices, while the onsite load continues to purchase all of its power requirements from the utility (the "net out" or "simultaneous purchase and sale" option), or 2) the QF can serve the on-site load directly and sell only excess generation to the utility (the "surplus sale" option). Both of these options are consistent with avoided cost principles.[3/] As Order 05-584 correctly states, FERC policy clearly allows QFs to sell their entire output (net of internal auxiliary loads) to the utility at avoided cost prices. The "surplus sale" option simply involves selling less power to the utility, also at avoided cost prices, because in this case the QF also serves its thermal host's onsite electric load, as well as its own auxiliary loads. Weyerhaeuser and ICNU believe that the QF should be allowed to choose the option that it deems to be most beneficial, as long as the selection is consistent with the utilities' applicable tariffs. Assuming that ratepayers are indifferent to the utility's purchase of the QF's entire output at avoided cost prices and that the utility's tariffed electric rates are just and reasonable, then ratepayers will not be harmed by the QF's election of the "simultaneous purchase and sale" option. Ratepayers also are indifferent if the utility simply purchases the QF's excess generation at avoided cost prices under a "surplus sale" contract.

[3/] The FERC has found that a QF may sell its generator's entire output, less its auxiliary use, to the utility at avoided cost rates. *See Connecticut Valley Elec. Co., Inc. v. FERC*, 208 F.3d 1037, 1040 (D.C. Cir. 2000), affirming *Connecticut Valley Elec. Co., Inc. v. Wheelabrator Claremont Co., L.P. and Related Actions*, 82 FERC ¶ 61,116 (1998) and 83 FERC ¶ 61,136 (1998) (order denying rehearing).

Q. ORDER NO. 05-584, AT 55-59, DECLINED TO APPROVE THE OPTION FOR LARGE QFS TO CHOOSE EITHER THE "SIMULTANEOUS PURCHASE AND SALE" OR THE "SURPLUS SALE" OPTIONS, IN PART BECAUSE THE PARTIES HAD NOT DISCUSSED WHETHER THE AVOIDED COST CALCULATION NEEDS TO BE MODIFIED TO REFLECT THE "SIMULTANEOUS PURCHASE AND SALE" OPTION. DO YOU BELIEVE THAT THE UTILITY'S AVOIDED COSTS WILL BE DIFFERENT DEPENDING ON WHICH OF THESE OPTIONS THE QF SELECTS?

A. No. The only significant difference between the "simultaneous purchase and sale" and the "surplus sale" options is the amount of power that is sold to the utility. Generally, a utility's avoided costs will not differ as a result of small variations in how much QF power the company purchases.

Q. SHOULD QFS HAVE THE UNFETTERED ABILITY TO SWITCH BETWEEN THE "SURPLUS SALE" AND THE "SIMULTANEOUS PURCHASE AND SALE" OPTIONS?

A. No. First, to the extent that a QF's election of the "simultaneous purchase and sale" option requires additional metering (for example, separate metering of the QF generation and the on-site load), the QF should bear the costs of those extra facilities. In addition, the on-site load should be required to observe all of the terms of service of the utility's tariff, including any requirements related to the term or termination of service. Thus, for example, if the utility's sales tariff requires a customer to commit to receive service under that tariff for a period of years, the customer would have to remain on the "simultaneous purchase and sale" option for that required term.

Q. COMMISSION ORDER NO. 05-584, AT 52-53, CITES PACIFICORP'S TESTIMONY STATING THAT IF BOTH OF THESE OPTIONS ARE AVAILABLE AT THE QF'S OPTION, THE QF WILL HAVE THE ABILITY TO SELECT THE LEAST EXPENSIVE OPTION, WHICH PACIFICORP DESCRIBES AS A CHANCE FOR THE QF "TO GAME THE DIFFERENCE BETWEEN THE COMPANY'S RETAIL RATES AND THE QF AVOIDED COST RATES."[4/] PLEASE RESPOND.

A. Order No. 05-584 cites PacifiCorp's initial opposition to Weyerhaeuser's proposal to allow a "simultaneous purchase and sale" option. The Company's opposition appears to have been based on a misunderstanding of Weyerhaeuser's testimony. Weyerhaeuser did not propose to allow a customer to change the terms of service of the utility's tariff, including requirements such as the minimum length of service. It is not "gaming" if a generator sells all of its generation to the utility at approved avoided costs rates that leave the ratepayer indifferent, and the on-site load buys its full requirements from the utility at a just and reasonable OPUC-approved tariff rate, so long as the load abides by all of the requirements of that tariff. Assuming that the Commission will set PacifiCorp's avoided cost rates accurately and tariffs include appropriate terms, ratepayers will be indifferent regardless of when the QF delivers power to the utility, or in what quantity. There is simply no "gaming" in providing a QF with both the "surplus sale" and the "simultaneous purchase and sale" options. This issue is a matter of fundamental fairness—the utility gets to set the costs of both options (with the Commission's approval); thus, it is equitable to let the customer choose which option to take. The person who slices the pie should let the other choose the first piece.

Although PacifiCorp initially opposed this proposal,[5/] its witness clarified at the 2004 hearings in this docket that PacifiCorp does not oppose such an option so long as the

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[4/] PPL/100, Widmer/28-29 (Rebuttal Testimony in Phase I) (Sept. 2004).
[5/] Id.

on-site load complies with all of the terms and conditions of the utility's tariff, including such conditions as the minimum term of service.[6/] In its Phase II order in this proceeding, the Commission should find that a QF of any size can choose either the "surplus sale" or the "simultaneous purchase and sale" option, whichever it deems to be most beneficial, so long as its on-site load complies with the utility's applicable tariffs.

III. NEGOTIATING PARAMETERS AND GUIDELINES FOR LARGE QFs

Q. ORDER NO. 05-584, AT 11, FINDS THAT "SIGNIFICANT BARRIERS EXIST TO THE NEGOTIATION OF NON-STANDARD CONTRACTS AND THAT THE DETAILED NEGOTIATION PARAMETERS AND GUIDELINES, AS WELL AS OTHER MEASURES, MAY OVERCOME THESE BARRIERS." THE COMMISSION FOUND THAT THE INITIAL PHASE OF THIS CASE FAILED TO ADEQUATELY "FRAME OR ADDRESS" THE ISSUES CONCERNING BARRIERS TO NON-STANDARD CONTRACTING, AND DEFERRED THESE ISSUES TO THIS PHASE. HOW DO WEYERHAEUSER AND ICNU PROPOSE TO FRAME THESE ISSUES?

A. The utilities have the ability to frustrate the development of QFs larger than the 10 MW size threshold for a standard contract and rates, by insisting in negotiations on unreasonable pricing or contractual concessions from large QFs. Weyerhaeuser and ICNU are not encouraged by the experience in Idaho—in the initial phase of this case, Idaho Power's witness testified that, although Idaho Power purchases electricity from 71 QFs, all are under standard contracts, and almost all are smaller than the 10 MW size threshold for standard agreements.[7/] As of the time of the UM 1129 hearings in October 2004, Idaho Power's 71 QFs averaged just 1.7 aMW in size, with 50 projects smaller than 3 MW.[8/] Clearly, in Idaho Power's Idaho service territory through 2004, it has made sense

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6/ Phase I Hearing Transcript ("Tr.") at 82: 3-5 (Oct. 28, 2004).

7/ It is my understanding that there are several projects larger than 10 MW that the Idaho Commission has allowed to use Idaho Power's standard rates and contract.

8/ Idaho Power, Gale/3-4, 13 (Rebuttal Testimony in Phase I) (Sept. 2004). The average of 1.7 aMW assumes that Idaho has 71 operating QFs with a capacity of 85 MW by the end of 2005, with an additional 5 projects with 45 MW of capacity on-line in 2006.

to develop QF projects that fall below the threshold for standard rates, so that one does not have to negotiate with the utility! Idaho Power's experience appears to show that if large QFs are not provided some assistance in negotiating contracts with the utility, few if any will succeed.

Order No. 05-584 proposes a compromise between simply telling large QFs to "go negotiate" (which Idaho Power's experience suggests will not be fruitful) and making the standard contract and rates available to QFs of all sizes (which the utilities warn could lead to an oversupply of QF power). That compromise is to formulate parameters and guidelines within which negotiations with large QFs are to be conducted. Weyerhaeuser and ICNU propose below a set of such guidelines, with a focus on the pricing terms that lie at the heart of every QF contract.

Q. THE UTILITIES HAVE ASSERTED, AND THE COMMISSION HAS AGREED, THAT NEGOTIATIONS WITH LARGE QFS ARE NECESSARY IN ORDER TO INCORPORATE INTO THE CONTRACTS FOR LARGE QFS THE FACTORS THAT THE FERC SETS FORTH IN 18 CFR §292.304[E] THAT SHOULD BE CONSIDERED IN SETTING AVOIDED COST RATES. WHAT GUIDANCE SHOULD THE COMMISSION PROVIDE ON EACH OF THESE FACTORS? [ISSUE 1D]

A. In the past, the Commission simply has stated that the standard avoided cost rates should be the starting point for negotiations. More detailed guidance can provide QFs larger than the adopted size threshold with a more complete and comprehensive set of terms as the basis for negotiations. Such standard terms also would provide the Commission with an approved set of terms that can serve as the "baseline" against which to judge the reasonableness of negotiated QF agreements. This baseline also can be valuable in assessing possible conflicts-of-interest in cases in which a QF (or a merchant generator) is affiliated with its purchasing utility.

I present below guidelines for each of the FERC pricing factors:

- **Reliability** (§292.304[e][2][ii]). QF contracts for firm power should provide incentives for reliable performance, through fixed dollar per kW-year capacity payments (based on the fixed costs of the avoided resource) that are tied to performance during the utility's peak time-of-use ("TOU") period. The QF would be entitled to receive, and the utility would be obligated to pay, the full firm capacity payment specified in the contract as long as the QF delivers the Contract Capacity during the peak hours of the peak months as defined in the contract ("Peak Period"), subject to a reasonable, industry-standard allowance for forced outages at the QF. The QF should receive incentive or "bonus" capacity payments for on-peak performance that is superior to the level required to earn 100% of the avoided capacity costs.

  For example, if the allowance for on-peak forced outages is 8%, the QF would earn a monthly capacity payment of 100% of the utility's avoided capacity costs if it achieved a 92% capacity factor during the on-peak period of the peak months. As an incentive, the QF could earn an additional 1% bonus capacity payment for each percent by which its capacity factor exceeds 92%. Similarly, the QF's capacity payments would be reduced proportionately to the extent that its capacity factor falls below the 92% standard. A QF that fails to provide its contract capacity during peak periods over an extended period should be subject to having its contract capacity de-rated until it can demonstrate its ability to provide a higher level of capacity.

In addition, the energy prices paid to QFs should be differentiated by time-of-use period in a way that reflects the utility's marginal energy costs by time-of-use period. Time-differentiated energy prices will provide an additional incentive for the QF to provide reliable on-peak production. PacifiCorp's avoided cost rates, for example, are time-differentiated into distinct rates for on- and off-peak periods.

As-available or non-firm QFs should receive capacity payments only to the extent that they actually deliver MWh during on-peak periods. Thus, for as-available QFs, avoided capacity costs should be expressed as a dollar per MWh rate allocated across all on-peak hours (with a modest allowance for forced outages). An as-available QF thus would have to operate at capacity in all on-peak hours to earn full capacity payments.

- **Dispatchability** (§292.304[e][2][i]). Dispatchability is best handled through time-of-use pricing, in recognition that CHP facilities may have no ability to allow the utility physically to dispatch their facilities, due to their need to provide highly reliable thermal energy to their hosts. In addition, PURPA requires utilities to purchase any capacity and energy that is "made available" to the utility by a QF.[9/] On the other hand, it is important that ratepayers not be harmed if the QF produces power during a low-demand period when the utility has little or no need for the power and may be

[9/] *See* 18 CFR §292.303[a].

selling excess generation on the market. Dispatch thus is an economic issue that should be handled through accurate time-differentiated avoided cost rates, with lower off-peak rates that reflect the utility's avoided costs during low-demand periods.[10/] If avoided cost rates are time-differentiated, large QFs should not be penalized if they cannot provide physical dispatch to the purchasing utility.

- **Termination** (§292.304[e][2][iii]). Termination provisions should keep the ratepayer whole if a QF receives capacity payments that are front-loaded or levelized compared to the comparable costs that the utility would recover in rates if it had built the avoided resource and placed that unit into its rate base on the same date when the QF begins operations. The QF should become liable for any remaining overpayments if it terminates its contract before its full term. **Exhibit Weyerhaeuser-ICNU/302** provides an example of a termination clause that requires the repayment of un-recovered front-loaded capacity payments.

- **Scheduling Outages** (§292.304[e][2][iv]). The Commission can specify that QFs should schedule major maintenance outages during non-peak months and can require QFs to provide the utility with reasonable advance notice of such outages. QFs should have a reasonable allowance for scheduled maintenance; if the QF stays within this allowance, it should not suffer a reduction in capacity payments. In other words, scheduled maintenance hours that are within the QF's allowance should not be used to

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10/ Weyerhaeuser proposed time-differentiated rates in Phase I of UM 1129. *See* Tr. 202: 3-22 (Beach). The Staff also supported time-differentiated avoided cost rates. *See* Tr. 112: 18-19 (Breen).

calculate the QF's achieved capacity factor used to determine capacity payments.

- **Emergencies** (§292.304[e][2][v]). QFs should have a "best efforts" obligation to deliver their contract capacity to the utility during system emergencies, which should be defined as a period when the integrity of the utility's system is threatened.
- **Line Losses and Locational Impacts.** (§292.304[e][4]). The Commission can require QF-specific transmission or line loss studies if a QF has a substantially different impact on a utility's line losses and transmission costs than does the avoided resource. For example, a QF located on a distribution line that also serves significant nearby loads may allow the utility to avoid losses at both the transmission and distribution levels. Also, a QF that is located in a remote area and that generates more power than can be absorbed by local loads may cause the utility to incur higher losses than the avoided resource. The utility should have a standard, transparent, timely process for conducting these studies and for quantifying such adjustments to avoided cost prices. PGE, Idaho Power and PacifiCorp should be required to propose in this proceeding how they intend to conduct these studies and how they will quantify these adjustments.

In its decision in this case, Weyerhaeuser and ICNU urge the Commission to include the above guidelines for utility negotiations with QFs that are larger than the adopted size threshold for standard rates and contracts. This is the single most important step that the Commission can take to assist utility and QF negotiations.

Q. THE UTILITIES HAVE IMPLIED THAT THE AVOIDED COST RATES INCLUDED IN THE STANDARD, TARIFFED QF CONTRACT REPRESENT A "PREMIUM" PRICE FOR QF POWER, THUS SUGGESTING THAT NEGOTIATED CONTRACTS WITH LARGE QFS ARE LIKELY TO RESULT IN PRICES LOWER THAN THE STANDARD RATES. DO YOU AGREE WITH THIS PERSPECTIVE?

A. No, I do not. The standard avoided cost rates do not represent a "premium" price. The FERC pricing factors can reduce or raise the final price for large QF power. Indeed, several of the FERC pricing factors recognize attributes of QF power that make their power <u>more</u> valuable to the utility than is reflected in standard avoided cost rates that are based on the deferral of a utility-owned resource:

- **Individual and Aggregate Value of Energy and Capacity** (§292.304[e][2][vi]). The aggregate value of QF production may be higher than the value of a single QF's production. For example, if a utility has 400 MWs of QFs on its system, the aggregate value of QF energy to the utility may be greater than the avoided energy costs calculated by comparing the utility's costs with and without a 50 MW QF, as PacifiCorp does.[11/] This is because the utility will have to pay a higher average price to replace 400 MW of QFs than to replace just 50 MW. Thus, the use of a 50 MW increment to calculate avoided costs may understate the aggregate value of QF power on a utility system that has more than 50 MWs of QF generation.

- **Smaller Capacity Increments and Shorter Lead Times** (§292.304[e][2][vii]). QFs provide a utility with a more diverse mix of resources and with a more dispersed and resilient generation portfolio. QF

[11/] Staff/100, Breen/15-16 (Direct Testimony in Phase I) (Aug. 3, 2004).

> capacity also can be added in smaller increments than large utility central station plants. Again, these are benefits of QF power that are not typically incorporated into the prices paid to QFs.

Weyerhaeuser and ICNU emphasize that these factors may produce avoided cost prices for large QFs that are higher than the utility's standard QF rates, yet still achieve ratepayer indifference. For example, Staff has correctly observed that locational adjustments may increase the rates paid to QFs located in load centers or to QFs that serve significant on-site loads, because such QFs may allow the utility to avoid transmission costs or to reduce line losses.[12/] Staff also has noted that current avoided cost rates do not reflect the savings that CHP or renewable QFs may produce by avoiding potential mitigation fees for carbon emissions.[13/] Further, the calculation of avoided costs may need to be revised as the number and capacity of QFs on a utility's system grows, because the impact of QFs on the IOU's unit costs will be greater than the costs avoided by any single QF. At this time, I do not recommend an adjustment to avoided costs rates to reflect these factors; instead, the Commission should recognize that such considerations often make QF power a good value for ratepayers at standard avoided cost rates.

Q. SHOULD THE NEGOTIATING GUIDELINES INCLUDE A REDUCTION IN THE PRICE PAID TO LARGE QFS TO REFLECT DEBT IMPUTED TO THE UTILITY'S CAPITAL STRUCTURE AS A RESULT OF THE PURCHASED POWER CONTRACT WITH A LARGE QF? [ISSUE 13]

A. I first observe that it is questionable whether QF power purchase agreements have a measurable impact on the capital structure of Oregon IOUs, given that QFs today

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12/ Staff/500, Breen/5 (Staff Surrebuttal Testimony) (Oct. 14, 2004). *See also* Tr. at 114: 23-25 (Breen) and Tr. at 134: 6-25 (Breen).

13/ Tr. at 115: 6-9 (Breen).

represent a small portion of the IOUs' resource portfolios.[14/] In addition, the assumption that QF power purchase agreements result in higher capital structure costs for the utility implies that the risks associated with QF power purchase agreements are higher than the risks associated with utility-owned resources or non-QF power purchase agreements. In fact, QFs assume many of the risks ordinarily borne by utilities in building new generation resources. The typical QF power purchase agreement pays the QF only to the extent that the QF actually delivers power to the utility. As a result, the QF bears the siting, construction, financing, and operational risks associated with its facility, risks that the utility would bear if it built the resource that QF power avoids. As I have discussed above, performance requirements in firm capacity QF contracts and time-differentiated pricing in as-available contracts will ensure that QFs have strong incentives to deliver power when it is most needed. The smaller size and distributed nature of QF generation reduces the risk to the utility from the loss of much larger central station units.

Finally, as the Commission recognized in Order No. 05-584, the utilities will have a high degree of assurance that QF costs are recoverable:

> While we agree with parties that QF power purchase contracts are unique among other power purchase contracts, we conclude that the unique characteristics of QF contracts already provide utilities with sufficient assurances, pursuant to the traditional regulatory compact that governs cost recovery, and that costs incurred under the contracts will be recovered. For example, in this Order, we have directed utilities to file QF power purchase standard contract forms. Those forms will be pre-approved for compliance with all standards set forth in this Order or still applicable prior orders. Although pre-approval of the standard contract form is not pre-approval of a utility's recovery of costs that are incurred under a particular standard contract, utilities are assured, to the extent a standard contract is entered into with a QF, that we have pre-approved the rates, terms and conditions of the agreement with the QF.

[14/] ICNU's testimony in the Policy Phase of UM 1129 showed that in 2002 QFs constituted less than 1% of the installed generating capacity in Oregon. ICNU/100, Schoenbeck/2-3 (Aug. 3, 2004).

Standard & Poor's has also recognized that QFs may provide utilities with significantly more risk mitigation than non-QF power purchase agreements, as they are "blessed by overarching federal legislation."[15/] The guidelines that the Commission will adopt in this phase related to non-standard QF contracts also should increase the utilities' comfort that the costs of non-standard QF contract costs will be recoverable in rates, as I discuss further below.

It is important to recognize several key facts about debt equivalence. First, there is no single formula for calculating the financial impacts of the debt equivalence of QF PPAs. Second, significant judgment is involved in these calculations; and, most important, this Commission can take significant steps to minimize or even eliminate the debt equivalence issue, by increasing the certainty that the utilities can recover the costs of prudently-administered QF contracts.

Notwithstanding the above considerations, if the Commission concludes based on substantial evidence that debt imputation represents a real and measurable cost to the utility from QF contracts, that cost should be reflected in the utility's filed avoided cost calculations. If power purchase contracts impose additional financial costs on a utility, it is the result of the utility's entire portfolio of such contracts, including all QF and non-QF contracts. QFs should not be unfairly penalized, especially when they are less risky than other resources. Furthermore, it would be simply unfair to require only large QFs to bear the impacts of debt imputation. With respect to debt imputation, four 5 MW power purchase agreements will have essentially the same impact on the utility's capital structure as one 20 MW contract.

15/ See Exhibit Weyerhaeuser-ICNU/303 (Standard & Poor's Utilities Perspectives (May 12, 2003)).

Q. WILL A WELL-DEFINED SET OF NEGOTIATING GUIDELINES BENEFIT THE UTILITIES?

A. Yes. In the initial phase of this proceeding, the utilities sought either advance Commission approval of QF contracts or Commission assurances that QF contract costs will be recoverable in rates.[16] In the section of Order No. 05-584 cited above, the Commission noted that its approval of a standard QF contract and rates provides significant assurance that QF costs will be recoverable in rates.

This phase provides the Commission with the opportunity to provide similar guidance with respect to non-standard QF contracts. If the Commission adopts the guidelines that Weyerhaeuser and ICNU have recommended, the utilities will have greater assurance concerning the terms that the Commission will find reasonable in negotiated QF contracts. Such direction will bring more certainty to utility and QF negotiations, to the Commission's subsequent review of the resulting QF contracts, and to the utility's ultimate recovery of its reasonable costs pursuant to those contracts.

IV. SPECIFIC CONTRACTUAL PROVISIONS FOR LARGE QFS

Q. IN ADDITION TO THE FERC PRICING FACTORS DISCUSSED ABOVE, HAS THE COMMISSION ASKED PARTIES TO ADDRESS OTHER CONTRACTUAL PROVISIONS APPLICABLE TO LARGE QFS?

A. Yes. The Commission's Order and list of Phase II issues asks parties to address the other issues related to contracts with large QFs. Below, I provide recommendations for the guidelines that the Commission should adopt for each of these issues:

- **What contract length should Qualifying Facilities larger than 10 MW be entitled to? [Order at 17; Issue 1a]** The Order recognized the tension between providing contracts that are long enough to allow QFs to finance

[16] *See* Order No. 05-584 at 55.

their projects (which the Oregon Department of Energy ("ODOE") persuasively argued to be up to 20 years) and the concern that ratepayers could run significant risks if avoided cost rates are fixed for as long as 20 years. As a result, the Order only allows avoided cost rates to be set for the initial 15 years of a 20-year contract, with the QF required to use a market pricing option for the final five years of the agreement.[17/]

The same provisions should be adopted as a guideline for large QF contracts—it is reasonable for large QF contracts to be up to 20 years in duration, with avoided cost rates set for the initial 15 years. QFs larger than 10 MW also must obtain financing for their capital costs; and to secure funding, they require the assurance of a long-term contract. In addition to the ODOE's testimony in the earlier phase of this case, the experience in California has been that 20-year contracts are necessary to stimulate significant development of large QFs, both CHP and renewable. The 10,000 MWs of large QF projects built in California in the 1980s were developed on the basis of 20- to 30-year contracts. More recently, the majority of the contracts for new renewable generation under California's Renewables Portfolio Standard program have been 20 years in duration, despite the availability of 10- and 15-year terms.[18/] Although California has the potential for 5,000 MW or more of new CHP development (including significant potential for projects over 10 MW), new projects are

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17/ *See* Order No. 05-584 at 20.

18/ In 2005, the CPUC approved 12 contracts for new renewable generation under the RPS program, totaling 874 MWs. Seven of the contracts, for 740 MWs, have 20-year terms; the remainder have 10, 12, or 15-year terms. *See* CPUC Commissioner Dian M. Grueneich, "*Moving Forward with California's Renewable Portfolio Standard*," November 3, 2005 presentation to the California Wind Energy Association, at 11.

not being developed due to the lack of long-term contracts with the IOUs.[19]

- **How should QF power supply commitments differentiate between "as available" and "legally enforceable obligations" for delivery of energy and capacity? [Issue 1b] How should "firm" or "non-firm" supply commitments be defined and differentiated through contractual default and damages provisions? [Issue 1c].** Weyerhaeuser and ICNU believe that the "firmness" of QF power supply commitments should be reflected first in the payment terms for QF contracts. As proposed above under the Reliability guideline, a QF that can provide firm capacity to the utility should be paid a firm capacity payment, in dollars per kW, based on the QF's achieved capacity factor during the peak hours of the peak months. A QF that fails to provide its contractual firm capacity (with a reasonable allowance for forced outages) over an extended period should be subject to having its contract capacity de-rated until it can demonstrate its ability to provide a higher level of capacity.

  In contrast, the avoided cost rates for an "as-available" or "non-firm" QF should be expressed in dollars per MWh, and should be paid solely on the basis of MWh delivered in each time-of-use period. As-available QFs can provide capacity value, provided they generate during the peak period hours. The capacity portion of as-available rates should be

[19] *See* the California Energy Commission's ("CEC") *2005 Integrated Energy Policy Report (2005 IEPR)*, at page 77. This section of the *2005 IEPR*, California's leading energy policy document, is quoted in Section VII of this testimony, below. The CEC's 2005 IEPR is available at http://www.energy.ca.gov/2005publications/CEC-100-2005-007/CEC-100-2005-007-CMF.PDF.

the utility's avoided cost of capacity (in dollars per kW-year) divided by the number of peak period hours and the capacity factor of the avoided resource. For example, PacifiCorp calculates the capacity portion of its on-peak avoided cost rates in 2010 (the first year of its deficiency period) by dividing the cost of a simple-cycle turbine ($80.27 per kW-year) by 4,993 peak period hours and an assumed capacity factor of 84.2%, to yield a capacity cost of $19.09 per MWh allocated to peak period avoided cost rates.

V. THE NEGOTIATION PROCESS

Q. REGARDING PACIFICORP'S SCHEDULE 38 FOR QUALIFYING FACILITIES LARGER THAN 10 MW, ARE THE PROCEDURES FOR NEGOTIATING AVOIDED COSTS, THE SCHEDULES FOR NEGOTIATIONS, AND THE INFORMATION TO BE EXCHANGED BY PACIFICORP AND THE QUALIFYING FACILITY REASONABLE? [ISSUE 1E]

A. Weyerhaeuser and ICNU propose two significant additions to the negotiating procedures set forth in PacifiCorp's Schedule 38. The Commission has made clear that negotiations with large QFs should start from the standard contract and standard rates that the Commission has approved. The purpose of the negotiations is to tailor the standard contract and rates to the specific circumstances of the large QFs, and in particular to reflect the pricing factors set forth in the FERC rules. Thus, when the utility tenders the indicative pricing proposal (Schedule 38, Section B.3), the utility should state in writing how it has modified the indicative prices from the standard rates, and should provide the quantitative basis for each such adjustment. Otherwise, the QF is left in the dark to guess at how the utility derived the indicative prices from the standard avoided cost rates. For example, during the sufficiency period when avoided cost rates are based on market prices, the utility should specify the factors that it used in developing the avoided cost rates, and how those factors have changed in the indicative pricing proposal. These factors should include the delivery point, firmness, reserve requirements, time-of-use adjustments, losses, and any other adjustments that the utility has made to standard avoided cost rates. Similarly, when the utility sends the QF a draft contract (Schedule 38, Section B.6), the utility should explain in writing how and why the terms of the draft have been modified from the standard agreement.

Q. **SHOULD THE UTILITY BE ALLOWED TO MODIFY THE STANDARD CONTRACT OR STANDARD AVOIDED COST RATES IN WAYS IN WHICH THE COMMISSION HAS NOT PROVIDED GUIDANCE IN THIS PROCEEDING? [ISSUE 1F]**

A. No. The purpose of this phase of UM 1129 is to streamline and clarify the negotiation process by specifying the parameters within which negotiations will occur. That purpose will be defeated if the utility has unlimited flexibility to negotiate each and every term of the contract, or to change standard avoided cost rates in ways that the Commission has not reviewed. Giving the utility *carte blanche* to modify avoided cost rates is likely to result in either fewer successful negotiations or greater need for Commission adjudication of disputes arising from negotiations related to large QF contracts.

VI. AVOIDED COST PRICES INDEXED TO NATURAL GAS

Q. DID ORDER NO. 05-584 PROVIDE THAT THE UTILITIES MUST INDEX THEIR AVOIDED COST PRICES TO NATURAL GAS PRICES?

A. Yes, it did. The Order finds that indexing avoided cost prices to natural gas prices provides a QF with the ability to choose a pricing option that best meets its operational needs, and advances the Commission's goal "to more accurately value avoided costs."[20/] For example, to the extent that avoided cost rates are based on the fixed and operating

[20/] Order No. 05-584 at 34.

costs of a new combined-cycle power plant—as they are for the period when the utilities are capacity deficient—a substantial portion of avoided costs will vary directly with natural gas prices. In Phase I of this implementation proceeding for Order No. 05-584, the Commission also will decide whether to extend gas indexing to avoided cost rates when they are based on forecasted electric market prices.[21/] Weyerhaeuser and ICNU support the indexing of electric market-based avoided costs to gas, because electric market prices in the West are strongly correlated with natural gas prices.

Q. IN ADDITION TO THE REASONS CITED IN THE ORDER, ARE THERE OTHER REASONS THAT AVOIDED COST RATES SHOULD BE INDEXED TO NATURAL GAS PRICES?

A. Yes. Indexing to gas prices is particularly important for gas-fired CHP QFs whose fuel costs will vary with natural gas prices and for whom fuel represents the major operating expense. Without avoided cost prices that are fully indexed to natural gas prices, the potential risks to project viability from volatile gas prices present a major barrier to CHP development. With indexing, CHP projects gain the assurance of a direct link between the major cost driver of both their input and output costs, reducing operating risk and promoting more stable output. Ratepayers will also benefit when natural gas prices decline if QF prices are tied to indexed natural gas prices.

Q. DO YOU KNOW OF ANY CONCEIVABLE REASON THAT AVOIDED COST RATES FOR LARGE QFS SHOULD NOT BE INDEXED TO NATURAL GAS PRICES IN THE SAME FASHION AS STANDARD RATES FOR SMALL QFS?

A. No. QFs both larger and smaller than the Commission's adopted 10 MW size threshold will avoid the same utility market purchases during the sufficiency period and the same combined cycle gas turbine project when the utility is capacity-deficient. The Commission has found that, although avoided cost rates for large QFs may be tailored

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[21/] *See* ICNU/200, Falkenberg/8-14 (Direct Testimony in Phase I Compliance Filing) (Dec. 9, 2005).

through negotiations to the individual circumstances of the large QF, the negotiations should start and be founded on the utility's filed avoided cost rates, which of course are the same rates that apply to small QFs. Although it may be reasonable for a utility to negotiate rates with a large QF that differ from standard rates due to the individual circumstances of that QF, those specific circumstances are highly unlikely to include the large QF somehow not avoiding the same resources or market purchases as small QFs. As a result, large QFs should have access to the same procedures to index avoided cost rates to natural gas that are available to small QFs. As provided in Order No. 05-584 at 35, the choice of the gas indexing option should be the QF's.

VII. COMPETITIVE BIDDING

Q. SHOULD COMPETITIVE BIDDING BE USED TO SET PRICING FOR QFS GREATER THAN A CERTAIN SIZE (E.G., LARGER THAN 100 MW) IF THE UTILITY HAS RECENTLY COMPLETED AN RFP, OR A BIDDING PROCESS IS IN PROGRESS OR IMMINENT? IF SO, HOW? [ISSUE 11]

A. Bids from competitive solicitations should not be used to set avoided cost rates unless the utility can justify, and the Commission approves, the use of such bids as the correct measure of the utility's avoided costs. If the utility makes such a request, the Commission will need to decide whether the product procured in the solicitation accurately represents the utility's avoided costs with respect to QF resources. If the Commission does decide to revise a utility's filed avoided cost rates as the result of a competitive solicitation, it should do so only on a prospective basis and only after following established procedures for changes to avoided cost rates. In assessing whether the results of a competitive solicitation have any relevance to a utility's avoided costs, the Commission should look carefully at whether the solicitation was structured to allow and to encourage QFs to bid, as an indication of whether the results of the solicitation are representative of the costs avoided by the types of power products that QFs can provide.

Q. SHOULD STATES RELY COMPLETELY ON PRICES DETERMINED IN COMPETITIVE SOLICITATIONS TO SET AVOIDED COST PRICES FOR LARGE QFS?

A. No. Washington State, for example, uses the results of competitive solicitations to set avoided cost rates for large QFs. This method has not stimulated the development of QF resources in Washington, particularly because the utilities can obtain resources through means other than solicitations, and can obtain waivers from the requirement to hold solicitations.[22/] As a result, avoided cost rates for large QFs in Washington can become stale and out-dated if the utility does not conduct a solicitation for many years. In addition, it appears that use of competitive bidding in Washington has provided the utilities with another tool to stonewall and to refuse to enter into contracts with cost effective QFs.

Q. SHOULD LARGE QFS BE REQUIRED TO PARTICIPATE IN COMPETITIVE SOLICITATIONS WITH OTHER TYPES OF RESOURCES, IN ORDER TO SECURE A CONTRACT WITH A UTILITY?

A. QFs should not be required to bid in such solicitations, although they also should not be precluded from doing so. In my experience, utility solicitations often are not tailored to the procurement of QF resources. Because QF resources often are powered by intermittent resources (as in the case of renewables) or are associated with industrial processes that have specific operating requirements (as in the case of CHP), QFs have difficulty meeting the dispatch or other operational requirements that utilities often seek in their solicitations. Many CHP projects, for example, face thermal production

[22/] The 2002 data on QF development that ICNU presented in the policy phase of UM 1129 showed that in 2002 QFs constituted just 1.7% of the installed generating capacity in Washington. *See* ICNU/102 (Exhibit in Phase I) (Aug. 3, 2004). For the Washington competitive bidding rules, *see* WAC § 480-107-001.

requirements that limit their operational flexibility and require them to operate in most hours, which generally prevent them from being able to provide fully dispatchable power.

Q. HAVE STATE POLICYMAKERS RECOGNIZED THE PROBLEMS THAT COGENERATION QFS FACE IN OBTAINING NEW OR RENEWED LONG-TERM CONTRACTS WITH THE IOUS?

A. Yes. Since 2003, the California IOUs have been relying on competitive solicitations to procure new resources, and have advocated requiring QFs that seek new power purchase contracts to participate in these solicitations. The IOU solicitations generally have sought physically dispatchable resources, which cogeneration QFs cannot provide if they need to provide thermal energy in a baseload profile for their thermal hosts. In addition, past utility solicitations in California have included 25 MW minimum bid requirements that excluded most QFs, as well as onerous credit provisions and the requirement that the QF function as its own scheduling coordinator. Northwest utilities also often have a 25 MW-size threshold for competitive bids.[23/] The most recent solicitations of Pacific Gas & Electric and Southern California Edison have invited QFs to participate, have relaxed the size limitation to 1 MW, and have indicated a willingness to consider baseload deliveries from QFs, but it remains unclear how successful those solicitations will be at retaining existing QF resources and attracting new projects.

In November 2005, the California Energy Commission recognized in its 2005 Integrated Energy Policy Report ("IEPR"), California's leading energy policy document, that the IOUs' solicitations were not resulting in the development of new CHP resources or the extension of existing CHP contracts with the IOUs. The CEC's 2005 IEPR clearly articulates both the problem and the solution:

23/ *See* ICNU/100, Schoenbeck/11-12 (Phase I Direct Testimony) (Aug. 3, 2004).

> The state also needs to improve access to wholesale energy markets and streamline the utilities' long-term contract processes so that CHP owners can easily and efficiently sell their excess electricity to their local utility. This would provide CHP owners with the certainty needed to guide their investment decisions to install or expand their CHP operations.
>
> Recent federal energy legislation suggests that the Public Utilities Regulatory Policies Act, enacted in 1978, is likely to remain in effect in California because of the lack of a robust and functioning wholesale market. By the end of 2006, the CPUC should require IOUs to buy, through standardized contracts, all electricity from CHP plants in their service territories at their avoided cost, as defined by the CPUC in R.04-04-025.[24/]

Q. DOES REQUIRING CHP QFS TO PARTICIPATE IN UTILITY SOLICITATIONS COMPLY WITH PURPA'S MANDATORY PURCHASE OBLIGATION?

A. No, it does not. PURPA requires the utility to purchase "any energy and capacity" that is "made available" to the utility by a QF, at rates equal to the utility's avoided cost.[25/] FERC's regulations allow a QF to elect to provide energy to the utility as the QF determines such energy to be "available," or pursuant to a contract that provides for delivery over a specified term.[26/] For example, the California Commission recently has held that PURPA can be satisfied by QFs' <u>voluntary</u> participation in utility solicitations, but has rejected proposals to require QFs to participate in solicitations as their only option.[27/]

Q. ARE THERE REASONS WHY A QF MIGHT WANT TO PARTICIPATE VOLUNTARILY IN A UTILITY SOLICITATION?

A. Yes. PURPA requires utilities to purchase QF power at avoided cost rates. Not surprisingly, this mandatory purchase obligation under PURPA has always been, to put it mildly, a source of tension between utilities and the QF community. QF participation in

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24/ 2005 IEPR at 77.

25/ 16 U.S.C. § 824a-3(b); 18 C.F.R. §292.303(a) (2003); *see also, American Paper Institute v. American Electric Power*, 461 U.S. 402 (1983).

26/ 18 C.F.R. § 292.304(d) (2004).

27/ CPUC Decision No. 04-01-050 at 154-55.

utility solicitations resolves this tension, because the QF is seeking to fill a need that the utility itself has identified. The challenge with solicitations is whether the utility's bid conditions will recognize and accommodate the unique needs of QFs, such as the need for CHP projects to satisfy the requirements of their thermal hosts. Provided that QFs have a fair opportunity to participate in a utility solicitation, QFs may decide to do so, in order to avoid the "need" debate, and in recognition that, if the utility fills its immediate resource needs through the solicitation, its avoided costs may drop as its future needs for generation are reduced or pushed out in time.

Q. DOES THIS COMPLETE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Weyerhaeuser-ICNU/301

R. Thomas Beach Qualifications

Mr. Beach is principal consultant with the consulting firm Crossborder Energy. Crossborder Energy provides intelligence, strategic advice, and economic consulting services on market and regulatory issues concerning the natural gas and electric industries. The firm is based in Berkeley, California, and its practice focuses on the energy markets in California, the western U.S., Canada, and Mexico.

Since 1989, Mr. Beach has participated actively in most of the major energy policy debates in California, including the addition of new natural gas pipeline capacity to serve the state, the restructuring of the state's gas and electric industries, and a wide range of issues concerning California's large independent power community. From 1981 through 1989 he served at the California Public Utilities Commission, including five years as an advisor to three CPUC commissioners. While at the CPUC, he was a key advisor on the CPUC's restructuring of the natural gas industry in California, and worked extensively on the state's implementation of PURPA.

AREAS OF EXPERTISE

- *Restructuring the Natural Gas and Electric Industries:* consulting and expert testimony on numerous issues in California's troubled restructuring of the state's electric industry. He has testified before the CPUC on transition cost and transmission pricing issues, and before the FERC on the protocols for California's Independent System Operator.

- *Energy Markets:* studies and consultation on the dynamics of natural gas and electric markets, including the impacts of new pipeline capacity on natural gas prices and of electric restructuring on wholesale electric prices.

- *Qualifying Facility Issues:* consulting with QF clients on a broad range of issues involving independent power facilities in California. He has negotiated complex QF contract restructurings with the California electric utilities, and is one of the leading experts in California on the calculation of avoided cost prices. Other QF issues on which he has worked include electric transmission and interconnection issues, property tax matters, electric standby rates, QF efficiency standards, and natural gas rates for cogenerators. Crossborder Energy's QF clients include the full range of QF technologies operating in California, both fossil-fueled and renewable.

- *Pricing Policy in Regulated Industries:* consulting and expert testimony on natural gas pipeline rates and on marginal cost-based rates for natural and electric distribution utilities.

EDUCATION

Mr. Beach holds a B.A. in English and physics from Dartmouth College, and an M.E. in mechanical engineering from the University of California at Berkeley.

ACADEMIC HONORS

Graduated from Dartmouth with high honors in physics and honors in English.
Chevron Fellowship, U.C. Berkeley, 1978-79

PROFESSIONAL ACCREDITATION

Registered professional engineer in the state of California.

EXPERT WITNESS TESTIMONY BEFORE THE CPUC

1. Prepared Direct Testimony on Behalf of **Pacific Gas & Electric Company/Pacific Gas Transmission** (I. 88-12-027 — July 15, 1989)

    - *Competitive and environmental benefits of new natural gas pipeline capacity to California.*

2. a. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (A. 89-08-024 — November 10, 1989)
   b. Prepared Rebuttal Testimony on Behalf of the **Canadian Producer Group** (A. 89-08-024 — November 30, 1989)

    - *Natural gas procurement policy; gas cost forecasting.*

3. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (R. 88-08-018 — December 7, 1989)

    - *Brokering of interstate pipeline capacity.*

4. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (A. 90-08-029 — November 1, 1990)

    - *Natural gas procurement policy; gas cost forecasting; brokerage fees.*

5. Prepared Direct Testimony on Behalf of the **Alberta Petroleum Marketing Commission and the Canadian Producer Group** (I. 86-06-005 — December 21, 1990)

    - *Firm and interruptible rates for noncore natural gas users*

6. a. Prepared Direct Testimony on Behalf of the **Alberta Petroleum Marketing Commission** (R. 88-08-018 — January 25, 1991)
   b. Prepared Responsive Testimony on Behalf of the **Alberta Petroleum Marketing Commission** (R. 88-08-018 — March 29, 1991)

   - *Brokering of interstate pipeline capacity; intrastate transportation policies.*

7. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (A. 90-08-029/Phase II — April 17, 1991)

   - *Natural gas brokerage and transport fees.*

8. Prepared Direct Testimony on Behalf of **LUZ Partnership Management** (A. 91-01-027 — July 15, 1991)

   - *Natural gas parity rates for cogenerators and solar powerplants.*

9. Prepared Joint Testimony of R. Thomas Beach and Dr. Robert B. Weisenmiller on Behalf of the **California Cogeneration Council** (I. 89-07-004 — July 15, 1991)

   - *Avoided cost pricing; use of published natural gas price indices to set avoided cost prices for qualifying facilities.*

10 a. Prepared Direct Testimony on Behalf of the **Indicated Expansion Shippers** (A. 89-04-033 — October 28, 1991)
   b. Prepared Rebuttal Testimony on Behalf of the **Indicated Expansion Shippers** (A. 89-04-0033 — November 26,1991)

   - *Natural gas pipeline rate design; cost/benefit analysis of rolled-in rates.*

11. Prepared Direct Testimony on Behalf of the **Independent Petroleum Association of Canada** (A. 91-04-003 — January 17, 1992)

   - *Natural gas procurement policy; prudence of past gas purchases.*

12 a. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (I.86-06-005/Phase II — June 18, 1992)
   b. Prepared Rebuttal Testimony on Behalf of the **California Cogeneration Council** (I. 86-06-005/Phase II — July 2, 1992)

   - *Long-Run Marginal Cost (LRMC) rate design for natural gas utilities.*

13. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (A. 92-10-017 — February 19, 1993)

    - *Performance-based ratemaking for electric utilities.*

14. Prepared Direct Testimony on Behalf of the **SEGS Projects** (C. 93-02-014/A. 93-03-053 — May 21, 1993)

    - *Natural gas transportation service for wholesale customers.*

15 a. Prepared Direct Testimony on Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038 — June 28, 1993)
   b. Prepared Rebuttal Testimony of Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038 — July 8, 1993)

    - *Natural gas pipeline rate design issues.*

16. a. Prepared Direct Testimony on Behalf of the **SEGS Projects** (C. 93-05-023 — November 10, 1993)
    b. Prepared Rebuttal Testimony on Behalf of the **SEGS Projects** (C. 93-05-023 — January 10, 1994)

    - *Utility overcharges for natural gas service; cogeneration parity issues.*

17. Prepared Direct Testimony on Behalf of the **City of Vernon** (A. 93-09-006/A. 93-08-022/A. 93-09-048 — June 17, 1994)

    - *Natural gas rate design for wholesale customers; retail competition issues.*

18. Prepared Direct Testimony of R. Thomas Beach on Behalf of the **SEGS Projects** (A. 94-01-021 — August 5, 1994)

    - *Natural gas rate design issues; rate parity for solar powerplants.*

19. Prepared Direct Testimony on Transition Cost Issues on Behalf of **Watson Cogeneration Company** (R. 94-04-031/I. 94-04-032 — December 5, 1994)

    - *Policy issues concerning the calculation, allocation, and recovery of transition costs associated with electric industry restructuring.*

20. Prepared Direct Testimony on Nuclear Cost Recovery Issues on Behalf of the **California Cogeneration Council** (A. 93-12-025/I. 94-02-002 — February 14, 1995)

    - *Recovery of above-market nuclear plant costs under electric restructuring.*

21. Prepared Direct Testimony on Behalf of the **Sacramento Municipal Utility District** (A. 94-11-015 — June 16, 1995)

    - *Natural gas rate design; unbundled mainline transportation rates.*

22. Prepared Direct Testimony on Behalf of **Watson Cogeneration Company** (A. 95-05-049 — September 11, 1995)

    - *Incremental Energy Rates; air quality compliance costs.*

23. a. Prepared Direct Testimony on Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038/A. 94-05-035/A. 94-06-034/A. 94-09-056/A. 94-06-044 — January 30, 1996)
    b. Prepared Rebuttal Testimony on Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038/A. 94-05-035/A. 94-06-034/A. 94-09-056/A. 94-06-044 — February 28, 1996)

    - *Natural gas market dynamics; gas pipeline rate design.*

24. Prepared Direct Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (A. 96-03-031 — July 12, 1996)

    - *Natural gas rate design: parity rates for cogenerators.*

25. Prepared Direct Testimony on Behalf of the **City of Vernon** (A. 96-10-038 — August 6, 1997)

    - *Impacts of a major utility merger on competition in natural gas and electric markets.*

26. a. Prepared Direct Testimony on Behalf of the **Electricity Generation Coalition** (A. 97-03-002 — December 18, 1997)
    b. Prepared Rebuttal Testimony on Behalf of the **Electricity Generation Coalition** (A. 97-03-002 — January 9, 1998)

    - *Natural gas rate design for gas-fired electric generators.*

27. Prepared Direct Testimony on Behalf of the **City of Vernon** (A. 97-03-015 — January 16, 1998)

    - *Natural gas service to Baja, California, Mexico.*

28. a. Prepared Direct Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (A. 98-10-012/A. 98-10-031/A. 98-07-005 — March 4, 1999).
    b. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (A. 98-10-012/A. 98-01-031/A. 98-07-005 — March 15, 1999).
    c. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (A. 98-10-012/A. 98-01-031/A. 98-07-005 — June 25, 1999).

    - *Natural gas cost allocation and rate design for gas-fired electric generators.*

29. a. Prepared Direct Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (R. 99-11-022 — February 11, 2000).
    b. Prepared Rebuttal Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (R. 99-11-022 — March 6, 2000).
    c. Prepared Direct Testimony on Line Loss Issues of behalf of the **California Cogeneration Council** (R. 99-11-022 — April 28, 2000).
    d. Supplemental Direct Testimony in Response to ALJ Cooke's Request on behalf of the **California Cogeneration Council and Watson Cogeneration Company** (R. 99-11-022 — April 28, 2000).
    e. Prepared Rebuttal Testimony on Line Loss Issues on behalf of the **California Cogeneration Council** (R. 99-11-022 — May 8, 2000).

    - *Market-based, avoided cost pricing for the electric output of gas-fired cogeneration facilities in the California market; electric line losses.*

30. a. Direct Testimony on behalf of the **Indicated Electric Generators** in Support of the Comprehensive Gas OII Settlement Agreement for Southern California Gas Company and San Diego Gas & Electric Company (I. 99-07-003 — May 5, 2000).
    b. Rebuttal Testimony in Support of the Comprehensive Settlement Agreement on behalf of the **Indicated Electric Generators** (I. 99-07-003 — May 19, 2000).

    - *Testimony in support of a comprehensive restructuring of natural gas rates and services on the Southern California Gas Company system. Natural gas cost allocation and rate design for gas-fired electric generators.*

31. a. Prepared Direct Testimony on the Cogeneration Gas Allowance on behalf of the **California Cogeneration Council** (A. 00-04-002 — September 1, 2000).
    b. Prepared Direct Testimony on behalf of **Southern Energy California** (A. 00-04-002 — September 1, 2000).

    - *Natural gas cost allocation and rate design for gas-fired electric generators.*

32. a. Prepared Direct Testimony on behalf of **Watson Cogeneration Company** (A. 00-06-032 — September 18, 2000).
    b. Prepared Rebuttal Testimony on behalf of **Watson Cogeneration Company** (A. 00-06-032 — October 6, 2000).

    - *Rate design for a natural gas "peaking service."*

33. a. Prepared Direct Testimony on behalf of **PG&E National Energy Group & Calpine Corporation** (I. 00-11-002—April 25, 2001).
    b. Prepared Rebuttal Testimony on behalf of **PG&E National Energy Group & Calpine Corporation** (I. 00-11-002—May 15, 2001).

    - *Terms and conditions of natural gas service to electric generators; gas curtailment policies.*

34. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (R. 99-11-022—May 7, 2001).
    b. Prepared Rebuttal Testimony on behalf of the **California Cogeneration Council** (R. 99-11-022—May 30, 2001).

    - *Avoided cost pricing for alternative energy producers in California.*

35. Testimony of R. Thomas Beach in Support of the Application of **Wild Goose Storage Inc.** (A. 01-06-029—June 18, 2001).

    - *Consumer benefits from expanded natural gas storage capacity in California.*

36. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Wild Goose Storage** (A. 01-06-029—November 2, 1991)

37. Prepared Direct Testimony of R. Thomas Beach on behalf of the **County of San Bernardino** (I. 01-06-047—December 14, 2001)

    - *Reasonableness review of a natural gas utility's procurement practices and storage operations.*

38. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 01-10-024—May 31, 2002)
    b. Prepared Supplemental Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 01-10-024—May 31, 2002)

    - *Electric procurement policies for California's electric utilities in the aftermath of the California energy crisis.*

39. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers & Technology Association** (R. 02-01-011—June 6, 2002)

- *"Exit fees" for direct access customers in California.*

40. Prepared Direct Testimony of R. Thomas Beach on behalf of the **County of San Bernardino** (A. 02-02-012 — August 5, 2002)

- *General rate case issues for a natural gas utility; reasonableness review of a natural gas utility's procurement practices.*

41. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association** (A. 98-07-003 — February 7, 2003)

- *Recovery of past utility procurement costs from direct access customers.*

42. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council, the California Manufacturers & Technology Association, Calpine Corporation, and Mirant Americas, Inc.** (A 01-10-011 — February 28, 2003)
b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council, the California Manufacturers & Technology Association, Calpine Corporation, and Mirant Americas, Inc.** (A 01-10-011 — March 24, 2003)

- *Rate design issues for Pacific Gas & Electric's gas transmission system (Gas Accord II).*

43. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers & Technology Association; Calpine Corporation; Duke Energy North America; Mirant Americas, Inc.; Watson Cogeneration Company; and West Coast Power, Inc.** (R. 02-06-041 — March 21, 2003)
b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Manufacturers & Technology Association; Calpine Corporation; Duke Energy North America; Mirant Americas, Inc.; Watson Cogeneration Company; and West Coast Power, Inc.** (R. 02-06-041 — April 4, 2003)

- *Cost allocation of above-market interstate pipeline costs for the California natural gas utilities.*

44. Prepared Direct Testimony of R. Thomas Beach and Nancy Rader on behalf of the **California Wind Energy Association** (R. 01-10-024 — April 1, 2003)

- *Design and implementation of a Renew able Portfolio Standard in California.*

45. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 01-10-024 — June 23, 2003)
    b. Prepared Supplemental Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 01-10-024 — June 29, 2003)

    - *Power procurement policies for electric utilities in California.*

46. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Indicated Commercial Parties** (02-05-004 — August 29, 2003)

    - *Electric revenue allocation and rate design for commercial customers in southern California.*

47. a. Prepared Direct Testimony of R. Thomas Beach on behalf of **Calpine Corporation and the California Cogeneration Council** (A. 04-03-021 — July 16, 2004)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Calpine Corporation and the California Cogeneration Council** (A. 04-03-021 — July 26, 2004)

    - *Policy and rate design issues for Pacific Gas & Electric's gas transmission system (Gas Accord III).*

48. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (A. 04-04-003 — August 6, 2004)

    - *Policy and contract issues concerning cogeneration QFs in California.*

49. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council and the California Manufacturers and Technology Association** (A. 04-07-044 — January 11, 2005)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council and the California Manufacturers and Technology Association** (A. 04-07-044 — January 28, 2005)

    - *Natural gas cost allocation and rate design for large transportation customers in northern California.*

50. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Solar Energy Industries Association** (R. 04-03-017 — April 28, 2005)

    - *Cost-effectiveness of the Million Solar Roofs Program*

51. Prepared Direct Testimony of R. Thomas Beach on behalf of **Watson Cogeneration Company, the Indicated Producers, and the California Manufacturing and Technology Association** (A. 04-12-004 — July 29, 2005)

    - *Natural gas rate design policy; integration of gas utility systems.*

52. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 04-04-003/R. 04-04-025 — August 31, 2005)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 04-04-003/R. 04-04-025 — October 28, 2005)

    - *Avoided cost rates and contracting policies for QFs in California*

53. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 05-05-023 — January 20, 2006)

    - *Electric marginal costs, revenue allocation, and rate design for commercial and industrial electric customers in southern California.*

EXPERT WITNESS TESTIMONY BEFORE THE NEVADA PUBLIC SERVICE COMMISSION

1. Pre-filed Direct Testimony on Behalf of the **Nevada Geothermal Industry Council** (Docket No. 97-2001—May 28, 1997)

    - *Avoided cost pricing for the electric output of geothermal generation facilities in Nevada.*

2. Pre-filed Direct Testimony on Behalf of **Nevada Sun-Peak Limited Partnership** (Docket No. 97-6008—September 5, 1997)

3. Pre-filed Direct Testimony on Behalf of the **Nevada Geothermal Industry Council** (Docket No. 98-2002 — June 18, 1998)

    - *Market-based, avoided cost pricing for the electric output of geothermal generation facilities in Nevada.*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC UTILITIES COMMISSION OF OREGON

1. a. Direct Testimony of Behalf of **Weyerhaeuser Company** (UM 1129 — August 3, 2004)
   b. Surrebuttal Testimony of Behalf of **Weyerhaeuser Company** (UM 1129 — October 14, 2004)

   - *Policies to promote the development of cogeneration and other qualifying facilities in Oregon.*

LITIGATION EXPERIENCE

Mr. Beach has been retained as an expert in a variety of civil litigation matters. His work has included the preparation of reports on the following topics:

- The calculation of damages in disputes over the pricing terms of a natural gas sales contract.
- The valuation of a contract for the purchase of power produced from wind generators.
- The compliance of cogeneration facilities with the policies and regulations applicable to Qualifying Facilities (QFs) under PURPA in California.
- Audit report on the obligations of a buyer and a seller under a direct access electric contract in the California market.
- The valuation of interstate pipeline capacity contracts.

In several of these matters, Mr. Beach was deposed by opposing counsel. Mr. Beach has also testified at trial in the bankruptcy of a major U.S. energy company.

Weyerhaeuser-ICNU/302

Sample Qualifying Facility Power Purchase Agreement Provisions for Capacity Termination, System Emergency Conditions, and Scheduled Maintenance Outages

Sample Qualifying Facility (QF) Power Purchase Agreement Provisions for Capacity Termination, System Emergency Conditions, and Scheduled Maintenance Outages.

A. Contract Capacity Termination

1.0 Performance Requirements. To receive the Monthly Capacity Payment in Section __, Seller shall provide the Contract Capacity in each Peak Month for all on-peak hours as such peak hours are defined in Utility's Tariff Schedule No. __ on file with the Commission, except that Seller is entitled to an 8% allowance for Forced Outages for each Peak Month. Seller shall not be subject to such performance requirements for the remaining hours of the year.

1.1 If Seller fails to meet the requirements specified in Section 1.0, Seller, in Utility's sole discretion, may be placed on probation for a period not to exceed 15 months. If Seller fails to meet the requirements specified in Section 1.0 during the probationary period, Utility may derate the Contract Capacity to the greater of the capacity actually delivered during the probationary period, or the capacity at which the Seller can reasonably meet such requirements. A reduction in Contract Capacity as a result of this Section 1.0 shall be subject to Section 2.0

2.0 Capacity Reduction. Subject to Section 2.1, Seller shall refund to Utility with interest at the current published Federal Reserve Board three months prime commercial paper rate an amount equal to the difference between (i) the accumulated Monthly Capacity Payments paid by Utility up to the time the reduction notice is received by Utility, and (ii) the total capacity payments which Utility would have paid if based on the Adjusted Capacity price.

2.1 Payments due to Contract Capacity Reduction

2.1.1 The parties agree that the refund and payments provided in Section 2.0 represent a fair compensation for the reasonable losses that would result from such reduction of Contract Capacity.

2.1.2 In the event of a reduction in Contract Capacity, the quantity, in kW, by which the Contract Capacity is reduced shall be used to calculate the refunds and payments due Utility in accordance with Section 2.0, as applicable.

2.1.3 Utility shall provide invoices to Seller for all refunds and payments due Utility under this section which shall be due within 60 days.

2.1.4. If Seller does not make payments as required in Section 10.4.3, Utility shall have the right to offset any amounts due it against any present or future payments due Seller and may pursue any other remedies available as a result of Seller's failure to perform.

2.2.0 Adjusted Capacity Price: The $/kW-yr capacity purchase price based on the Capacity Payment Schedule in effect at time of Contract execution for the time period beginning on the date of Firm Operation for the first generating unit and ending on the date of termination or reduction of Contract Capacity.

2.2.1 Contract Capacity: The electric power producing capability of the Generating Facility which is committed to Utility.

2.2.2 Contract Capacity Price: The capacity purchase price from the Capacity Payment Schedule approved by the Commission.

2.2.4 Contract Term: Period in years commencing with date of Firm Operation for the first generating unit(s) during which Utility shall purchase electric power from Seller.

2.2.5 Current Capacity Price: The $/kW-yr capacity price provided in the Capacity Payment Schedule determined by the year of termination or reduction of Contract Capacity and the number of years from such termination or reduction to the expiration of the Contract Term.

2.2.6 Firm Operation Date : The date agreed on by the Parties on which each generating unit(s) of the Generating Facility is determined to be a reliable source of generation and on which such unit can be reasonably expected to operate continuously at its effective rating (expressed in kW).

B. System Emergency

3.0 At Utility's request, Seller shall make all reasonable effort to deliver power at an average rate of delivery at least equal to the Contract Capacity during periods of Emergency. In the event that the Seller has previously scheduled an outage coincident with an Emergency, Seller shall make all reasonable efforts to reschedule the outage. The notification periods listed in Section 4.0 shall be waived by Utility if Seller reschedules the outage.

3.1.1 Utility Electric System Integrity: The state of operation of Utility's electric system in a manner which is deemed to minimize the risk of injury to persons and/or property and enables Utility to provide adequate and reliable electric service to its customers.

3.1.2 Emergency: A condition or situation which in Utility's sole judgment affects Utility Electric System Integrity.

C. Scheduled Maintenance

4.0 Each Party shall keep the other Party's Operating Representative informed as to the operating schedule of their respective facilities affecting each other's operation hereunder, including any reduction in Contract Capacity availability. In addition, Seller shall provide Utility with reasonable advance notice regarding its scheduled outages including any reduction in Contract Capacity availability. Reasonable advance notice is as follows:

SCHEDULED OUTAGE EXPECTED DURATION	ADVANCE NOTICE TO Utility
Less than one day One day or more (except for major overhauls) Major overhaul	24 Hours 1 Week 6 Months

4.1 Notification by each Party's Operating Representative of outage date and duration should be directed to the other Party's Operating Representative by telephone.

4.2 Seller shall not schedule major overhauls during Peak Months

4.3 Maintenance

4.3.1 Seller shall maintain the Generating Facility in accordance with applicable utility industry standards and good engineering and operating practices. Utility shall have the right to monitor such maintenance of the Generating Facility. Seller shall maintain and deliver a maintenance record of the Generating Facility to Utility's Operating Representatives upon request.

4.3.2 Seller shall make a reasonable effort to schedule routine maintenance during Off-Peak Months. Outages for scheduled maintenance shall not exceed a total of 30 peak hours for the Peak Months.

4.3.3 The allowance for scheduled maintenance is as follows:
Outage periods for scheduled maintenance shall not exceed 840 hours (35 days) in any 12-month period. This allowance may be used in increments of an hour or longer on a consecutive basis. Seller may accumulate unused maintenance hours on a year-to-year basis up to a maximum of 1,080 hours (45 days). This accrued time must be used consecutively and only for major overhauls.

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STANDARD & POOR'S

"Buy Versus Build": Debt Aspects of Purchased-Power Agreements

Standard & Poor's Ratings Services views electric utility purchased-power agreements (PPA) as debt-like in nature, and has historically capitalized these obligations on a sliding scale known as a "risk spectrum." Standard & Poor's applies a 0% to 100% "risk factor" to the net present value (NPV) of the PPA capacity payments, and designates this amount as the debt equivalent.

While determination of the appropriate risk factor takes several variables into consideration, including the economics of the power and regulatory treatment, the overwhelming factor in selecting a risk factor has been a distinction in the likelihood of payment by the buyer. Specifically, Standard & Poor's has divided the PPA universe into two broad categories: take-or-pay contracts (TOP; hell or high water) and take-and-pay contracts (TAP; performance based). To date, TAP contracts have been treated far more leniently (e.g., a lower risk factor is applied) than TOP contracts since failure of the seller to deliver energy, or perform, results in an attendant reduction in payment by the buyer. Thus, TAP contracts were deemed substantially less debt-like. In fact, the risk factor used for many TAP obligations has been as low as 5% or 10% as opposed to TOPs, which have been typically at least 50%.

Standard & Poor's originally published its purchased-power criteria in 1990, and updated it in 1993. Over the past decade, the industry underwent significant changes related to deregulation and acquired a history with regard to the performance and reliability of third-party generators. In general, independent generation has performed well; the likelihood of nondelivery—and thus release from the payment obligation—is low. As a result, Standard & Poor's believes that the distinction between TOPs and TAPs is minimal, the result being that the risk factor for TAPs will become more stringent. This article reiterates Standard & Poor's views on purchased power as a fixed obligation, how to quantify this risk, and the credit ramifications of purchasing power in light of updated observations.

Why Capitalize PPAs?

Standard & Poor's evaluates the benefits and risks of purchased power by adjusting a purchasing utility's reported financial statements to allow for more meaningful comparisons with utilities that build generation. Utilities that build typically finance construction with a mix of debt and equity. A utility that leases a power plant has entered into a debt transaction for that facility; a capital lease appears on the utility's balance sheet as debt. A PPA is a similar fixed commitment. When a utility enters into a long-term PPA with a fixed-cost component, it takes on financial risk. Furthermore, utilities are typically not financially compensated for the risks they assume in purchasing power, as purchased power is usually recovered dollar-for-dollar as an operating expense.

As electricity deregulation has progressed in some countries, states, and regions, the line has blurred between traditional utilities, vertically integrated utilities, and merchant energy companies, all of which are in the generation business. A common contract that has emerged is the tolling agreement, which gives an energy merchant company the right to purchase power from a specific power plant. (see "Evaluating Debt Aspects of Power Tolling Agreements," published Aug. 26, 2002). The energy merchant, or toller, is typically responsible for procuring and delivering gas to the plant when it wants the plant to generate power. The power plant operator must maintain plant availability and produce electricity at a contractual heat rate. Thus, tolling contracts exhibit characteristics of both PPAs and leases. However, tollers are typically unregulated entities competing in a competitive marketplace. Standard & Poor's has determined that a 70% risk factor should be applied to the NPV of the fixed tolling payments, reflecting its assessment of the risks borne by the toller, which are:

- Fixed payments that cover debt financing of power plant (typically highly leveraged at about 70%),
- Commodity price of inputs,
- Energy sales (price and volume), and
- Counterparty risk.

Determining the Risk Factor for PPAs

Alternatively, most entities entering into long-term PPAs, as an alternative to building and owning power plants, continue to be regulated utilities. Observations over time indicate the high likelihood of performance on TAP commitments and, thus, the high likelihood that utilities must make fixed payments. However, Standard & Poor's believes that vertically integrated, regulated utilities are afforded greater protection in the recovery of PPAs, compared with the recovery of fixed tolling charges by merchant generators. There are two reasons for this. First, tariffs are typically set by regulators to recover costs. Second, most vertically integrated utilities continue to have captive customers and an obligation to serve. At a minimum, purchased power, similar to capital costs and fuel costs, is included in tariffs as a cost of service.

As a generic guideline for utilities with PPAs included as an operating expense in base tariffs, Standard & Poor's believes that a 50% risk factor is appropriate for long-term commitments (e.g. tenors greater than three years). This risk factor assumes adequate regulatory treatment, including recognition of the PPA in tariffs; otherwise a higher risk factor could be adopted to indicate greater risk of recovery. Standard & Poor's will apply a 50% risk factor to the capacity

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component of both TAP and TOP PPAs. Where the capacity component is not broken out separately, we will assume that 50% of the payment is the capacity payment. Furthermore, Standard & Poor's will take counterparty risk into account when considering the risk factor. If a utility relies on any individual seller for a material portion of its energy needs, the risk of nondelivery will be assessed. To the extent that energy is not delivered, the utility will be exposed to replacing this power, potentially at market rates that could be higher than contracted rates and potentially not recoverable in tariffs.

Standard & Poor's continues to view the recovery of purchased-power costs via a fuel-adjustment clause, as opposed to base tariffs, as a material risk mitigant. A monthly or quarterly adjustment mechanism would ensure dollar-for-dollar recovery of fixed payments without having to receive approval from regulators for changes in fuel costs. This is superior to base tariff treatment, where variations in volume sales could result in under-recovery if demand is sluggish or contracting. For 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. In certain cases, Standard & Poor's may consider a lower risk factor of 10% to 20% for distribution utilities where recovery of certain costs, including stranded assets, has been legislated. Qualifying facilities that are blessed by overarching federal legislation may also fall into this category. This situation would be more typical of a utility that is transitioning from a vertically integrated to a disaggregated distribution company. Still, it is unlikely that no portion of a PPA would be capitalized (zero risk factor) under any circumstances.

The previous scenarios address how purchased power is quantified for a vertically integrated utility with a bundled tariff. However, as the industry transitions to disaggregation and deregulation, various hybrid models have emerged. For example, a utility can have a deregulated merchant energy subsidiary, which buys power and off-sells it to the regulated utility. The utility in turn passes this power through to customers via a fuel-adjustment mechanism. For the merchant entity, a 70% risk factor would likely be applied to such a TAP or tolling scheme. But for the utility, a 30% risk factor would be used. What would be the appropriate treatment here? In part, the decision would be driven by the ratings methodology for the family of companies. Starting from a consolidated perspective, Standard & Poor's would use a 30% risk factor to calculate one debt equivalent on the consolidated balance sheet given that for the consolidated entity the risk of recovery would ultimately be through the utility's tariff. However, if the merchant energy company were deemed noncore and its rating was more a reflection of its stand-alone creditworthiness, Standard & Poor's would impute a debt equivalent using a 70% risk factor to its balance sheet, as well as a 30% risk-adjusted debt equivalent to the utility. Indeed, this is how the purchases would be reflected for both companies if there were no ownership relationship. This example is perhaps overly simplistic because there will be many variations on this theme. However, Standard & Poor's will apply this logic as

Table 1

ABC Utility Co. Adjustment to Capital Structure

	Original capital structure		**Adjusted capital structure**	
	$	**%**	**$**	**%**
Debt	1,400	54	1,400	48
Adjustment to debt	—	—	327	11
Preferred stock	200	8	200	7
Common equity	1,000	38	1,000	34
Total capitalization	2,600	100	2,927	100

Table 2

ABC Utility Co. Adjustment to Pretax Interest Coverage

		Original pretax interest coverage		**Adjusted pretax interest coverage**	
Net income	120				
Income taxes	65	300		(300+33)	
Interest expense	115	115	= 2.6x	(115+33)	= 2.3x
Pretax available	300				

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a starting point, and modify the analysis case-by-case, commensurate with the risk to the various participants.

Adjusting Financial Ratios

Standard & Poor's begins by taking the NPV of the annual capacity payments over the life of the contract. The rationale for not capitalizing the energy component, even though it is also a nondiscretionary fixed payment, is to equate the comparison between utilities that buy versus build—i.e., Standard & Poor's does not capitalize utility fuel contracts. In cases where the capacity and energy components of the fixed payment are not specified, half of the fixed payment is used as a proxy for the capacity payment. The discount rate is 10%. To determine the debt equivalent, the NPV is multiplied by the risk factor. The resulting amount is added to a utility's reported debt to calculate adjusted debt. Similarly, Standard & Poor's imputes an associated interest expense equivalent of 10%—10% of the debt equivalent is added to reported interest expense to calculate adjusted interest coverage ratios. Key ratios affected include debt as a percentage of total capital, funds from operations (FFO) to debt, pretax interest coverage, and FFO interest coverage. Clearly, the higher the risk factor, the greater the effect on adjusted financial ratios. When analyzing forecasts, the NPV of the PPA will typically decrease as the maturity of the contract approaches.

Utility Company Example

To illustrate some of the financial adjustments, consider the simple example of ABC Utility Co. buying power from XYZ Independent Power Co. Under the terms of the contract, annual payments made by ABC Utility start at $90 million in 2003 and rise 5% per year through the contract's expiration in 2023. The NPV of these obligations over the life of the contract discounted at 10% is $1.09 billion. In ABC's case, Standard & Poor's chose a 30% risk factor, which when multiplied by the obligation results in $327 million. Table 1 illustrates the adjustment to ABC's capital structure, where the $327 million debt equivalent is added as debt, causing ABC's total debt to capitalization to rise to 59% from 54% (48 plus 11). Table 2 shows that ABC's pretax interest coverage was 2.6x, without adjusting for off-balance-sheet obligations. To adjust for the XYZ capacity payments, the $327 million debt adjustment is multiplied by a 10% interest rate to arrive at about $33 million. When this amount is added to both the numerator and the denominator, adjusted pretax interest coverage falls to 2.3x.

Credit Implications

The credit implications of the updated criteria are that Standard & Poor's now believes that historical risk factors applied to TAP contracts with favorable recovery mechanisms are insufficient to capture the financial risk of these fixed obligations. Indeed, in many cases where 5% and 10% risk factors were applied, the change in adjusted financial ratios (from unadjusted) was negligible and had no effect on ratings. Standard & Poor's views the high probability of energy delivery and attendant payment warrants recognition of a higher debt equivalent when capitalizing PPAs. Standard & Poor's will attempt to identify utilities that are more vulnerable to modifications in purchased-power adjustments. Utilities can offset these financial adjustments by recognizing purchased power as a debt equivalent, and incorporating more common equity in their capital structures. However, Standard & Poor's is aware that utilities have been reluctant to take this action because many regulators will not recognize the necessity for, and authorize a return on, this additional wedge of common equity. Alternatively, regulators could authorize higher returns on existing common equity or provide an incentive return mechanism for economic purchases. Notwithstanding unsupportive regulators, the burden will still fall on utilities to offset the financial risk associated with purchases by either qualitative or quantitative means. ■

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CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served the Direct Testimony of R. Thomas Beach on behalf of Weyerhaeuser Company and the Industrial Customers of Northwest Utilities upon the parties, shown below, on the official service list by causing the foregoing document to be deposited, postage-prepaid, in the U.S. Mail, or by service via electronic mail to those parties who waived paper service.

DATED at Portland, Oregon, this 27th day of February, 2006.

DAVISON VAN CLEVE, P.C.

/s/ Anna E. Studenny
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