BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

POTLATCH CORPORATION, Complainant v. AVISTA UTILITIES, Respondent	))))))))	CASE NO. AVU-E-02-8

DIRECT TESTIMONY

OF

DENNIS E. PESEAU

ON BEHALF OF

POTLATCH CORPORATION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Dennis E. Peseau. My business address is Suite 250, 1500 Liberty Street, S.E., Salem, Oregon 97302.

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

A. I am the President of Utility Resources, Inc. ("URI"). URI has consulted on a number of economic, financial and engineering matters for various private and public entities for more than twenty years.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My resume is attached as Exhibit No. 1.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION?

A. Yes, many times. In addition, I have testified on the subject of avoided costs before this Commission on numerous occasions since the 1980s.

Q. FOR WHOM ARE YOU APPEARING IN THIS CASE?

A. I am appearing on behalf of Potlatch Corporation.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The ultimate purpose of my testimony is to make a recommendation to the Commission on the best method of resolving the complaint in this case. To that end, I will first briefly discuss how the current impasse between Potlatch and Avista came about. I will then examine Avista's proposal to Potlatch and explain why it is inconsistent with PURPA's requirements and this Commission's orders governing

PURPA purchases. Finally, I will propose a method of resolving the controversy that is fair to both Avista and its ratepayers and to Potlatch.

Q. PLEASE DESCRIBE HOW THE DISPUTE IN THIS CASE AROSE.

A. The Commission is well aware of most aspects of the long history between Potlatch and Avista, so I will confine my remarks to a brief summary of the relevant facts. Prior to December 31, 2001, Potlatch and Avista were parties to an Electric Service and Purchase Agreement dated January 3, 1991 ("1991 Agreement"). This lengthy and complex agreement provided for the purchase of all of Potlatch's electric energy needs for its Lewiston facilities from Avista and for the simultaneous sale to Avista of a maximum of 59 megawatts of energy from Potlatch's four cogeneration units.

During the last year of the 1991 Agreement's existence, attempts to negotiate a successor agreement broke down. Potlatch's first concern was obviously with its electric supply, so on March 23, 2001, Potlatch filed a petition with this Commission seeking a determination of the terms and conditions of electric service from Avista to Potlatch's Lewiston facility. IPUC Case No. AVU-E-01-5. On August 17, 2001, shortly before the scheduled commencement of hearings, the parties were able to reach a settlement that provided for continued Avista service to Potlatch at Schedule 25 rates until a new special contract rate could be established in Avista's next general rate case.

With its supply situation resolved, Potlatch turned its attention to the sale of its cogeneration output. On October 2, 2001, Potlatch sent Avista a written request for a firm avoided cost quote for the purchase of its cogeneration. This request contained the information required by applicable Commission orders. A copy is attached as Exhibit 2. The request also proposed that the parties meet on October 12, 2001, to begin contract negotiations.

Q. DID THE PARTIES IN FACT MEET ON OCTOBER 12TH?

A. Yes. Meetings were held on October 12th, November 14th, and December 12th. I did not attend these meetings, but I have reviewed the written materials that Avista provided as well as the follow up correspondence between the parties. I should mention parenthetically that Rick Sterling attended the November and December meetings on behalf of the Commission Staff.

Q. DID AVISTA PROVIDE POTLATCH WITH A FIRM QUOTE FOR THE PURCHASE OF ITS COGENERATION AT THESE MEETINGS?

A. Yes. Avista offered Potlatch $30.95 per megawatt hour for a 5 year contract. The contract price was, however subject to a $1.14/mwh offset for reserves that Avista insisted were Potlatch's responsibility, making the net price $29.81/mwh. The offer was also subject to a liquidated damages provision for non delivery, which subsequent correspondence priced at $5.00/mwh or 20% of the price, whichever is greater. The offer is summarized in the hand out Avista distributed at the November 14th meeting, which I have attached as Exhibit 3.

For the purpose of this testimony, I have treated the offering price as $30.95 because there is absolutely no authority in the Commission's orders for Avista's attempt to impose liquidated damages, reserve charges or any other ancillary charges on a QF sale.

Q. HOW DID AVISTA ARRIVE AT THIS PROPOSED PRICE?

A. According to Avista, it calculated the price in accordance with the requirements of Commission Order No. 26576. That order was promulgated on September 4, 1996 in IPUC Case No. IPC-E-95-9 in order to prescribe a new methodology for avoided cost rate negotiations for Qualifying Facilities ("QF") of one megawatt or larger.

Q. DOES AVISTA'S RATE CALCULATION IN FACT COMPLY WITH THE REQUIREMENTS OF ORDER NO. 26576?

A. In my judgment, it complies with neither the letter nor the spirit of the order, and it clearly does not produce the results the Commission envisioned when it signed the order.

Q. PLEASE EXPLAIN.

A. Order No. 26576 adopted a new avoided cost methodology for large QFs that was devised primarily in the course of settlement discussions between the Idaho utilities and the Commission Staff.[1] In essence, the new methodology attempted to produce an objective calculation of avoided costs by requiring utilities to model QF driven changes to the utilities' Integrated Resource Plans ("IRP"). The ultimate objective was to peg avoided cost rates to "the difference in the present value of revenue requirements (PVRR) between the base case resource plan and a modified resource plan that includes the QF resource." Settlement Stipulation at 4. This result was to be accomplished through a complex seven-step process described as follows in the Settlement Stipulation:

> 1. An IRP is prepared for the utility. The IRP should consider a range of load forecasts for various sets of possible economic conditions. The IRP should also consider all possible resources for meeting load, both supply and demand side. In addition,

[1] A few Idaho independent power producers apparently participated in the settlement discussions to some degree, but they did not sign the resulting Settlement/ Stipulation.

consideration should be given to the risks and uncertainties associated with each scenario examined. The least cost combination of resources is selected to meet each scenario. The most likely scenario is identified as the base case plan

2. An initial simulation analysis using a power supply and/or capacity expansion model chosen by the utility is used to calculate the PVRR of the base case resource plan over the lifetime of the proposed QF contract.

3. The proposed QF resource is added to the base case resource plan during all years of the proposed contract. The required description of the QF project includes all data and information needed to model the intended dispatchable or non-dispatchable operation of the project on the power supply system (see pps. 9-10 for a list of data and information needed from QFs.)

4. A second simulation analysis, including the QF resource, is performed which results in an adjustment of the amount and/or timing of the new resources in the base case plan. The modified plan including the QF purchase is constructed to maintain resource adequacy and system reliability equivalent to that of the base case plan.

5. The PVRR of the modified resource plan including the QF is calculated over the full term of the QF contract, excluding the total costs of the QF resource itself.

6. Finally, the present value of the QF project avoided cost is calculated by subtracting the PVRR of the modified plan, with costs of the QF set to zero, from the PVRR of the base case plan.

7. Rates for capacity and energy from the QF project can now be developed for which, on a present value basis, the expected payments to the QF are equal to the project's avoided cost over the life of the contract.

Q. DID AVISTA FOLLOW THIS PROCEDURE IN CALCULATING THE PRICE IT OFFERED TO POTLATCH?

A. While I have no doubt that Avista probably has workpapers, complete with multiple runs of the proprietary Prosym model, to prove that it actually followed this seven step procedure, the simple fact is that the whole exercise was, is, and continues to be, nonsensical for the purpose of correctly computing avoided costs.

Q. WHY DO YOU CHARACTERIZE AVISTA'S MODELING EFFORTS AS NONSENSICAL?

A. Avista's interpretation of the process devised in Order No. 26576 is nonsensical because, regardless of the inputs or the nature of the QF resource being modeled, the answer is always the same—<u>the supposedly modeled avoided costs are always equal to forward market prices at the time the model is run</u>. In short, the Prosym modeling exercise is irrelevant. You can get the same answer by just consulting a single input—market prices. The reason that market prices always equal avoided costs is that Avista's model does not allow actual or planned resources to be deferred by the avoided cost resource. If it can't defer resources, the model can't simulate the Surrogate Avoidable Resource found prudent in GNR-E-02-1. This is a fatal flaw in the modeling process.

Q. IS THAT BECAUSE AVISTA HAS SURPLUS RESOURCES AND HAS NO NEED FOR POTLATCH'S POWER?

A. No. On November 14, 2001, the same day that Avista presented its offer to Potlatch, Avista also filed its response to Commission Order No. 28884. That order required Avista to submit a revised load/resource balance sheet to reflect changes to Avista's IRP. I have attached a copy of Avista's filing as Exhibit 4. This exhibit shows that, even with Coyote Springs II coming on line in 2002 (which did not in fact occur), Avista has an annual average energy deficit in every single year. Even if all resources currently under construction come on line as scheduled, Exhibit 4 projects an average energy deficit of 108 megawatts in 2004 and constantly rising deficits every year thereafter. In reviewing the evidence at the time, the Commission Staff concluded that it "confirms an immediate need for new generation resources and demonstrates additional needs in the not too distant future." Order No. 28884 at 2.

Paradoxically, the fact that Avista needs precisely the type of base load resource that Potlatch can provide has no effect whatever on Avista's calculation of avoided costs. In fact, Avista's resource deficiency could grow much larger and still have no effect on Avista's calculated value of the Potlatch resource.

Q. HOW DO YOU KNOW THAT?

A. Avista admits as much. In Staff Data Request No. 3, Staff asked Avista to show the avoided cost rate with and without the Coyote Springs II generating station included in the base case. Avista responded as follows:

> Two runs were performed in AURORA for Request 3. The first run with CSII in the Company's resource portfolio and developed market prices in this case. The second was done without CSII. Refer to the workbook entitled "Request 3" in the file "February Offer Analysis-AURORA.xls" (provided in electronic format on an attached diskette in answer to Staff Production Requests 2 and 3) to see that the market prices of power during the January 2003 through December 2008 (taken from the AREA PRICE table of the AURORA run of Request 2) <u>are identical in both alternatives, and therefore that the avoided cost rate calculated in this manner is the same as the E-95-9 Rate</u>, at $34.05/MWH for March 2003 through February 2008.

(Emphasis added). This result is not only counter-intuitive, it is also inconsistent with the clear language of the Commission's order. In Order No. 26576, the Commission stated that, "the value of power from the QF is dictated by the type, amount, timing and cost of the resources in the IRP which would be displaced or deferred." Order No. 26576 at 2. Thus, if a QF purchase could displace or defer the cost of Coyote Springs II, the avoided cost should be largely driven by the cost of that displaced or deferred resource. This was a major purpose of GNR-E-02-1. But using Avista's methodology, the cost of that displacement or deferral is irrelevant because avoided cost always equals projected market prices.

Q. DO YOU THINK THIS WAS THE COMMISSION'S INTENDED RESULT WHEN IT SIGNED ORDER NO. 26576?

A. I am confident it was not. In the first place, Avista's results are clearly at odds with the Commission language I just quoted. Furthermore, if the Commission had intended that avoided costs would always equal estimated market prices, it presumably would have said so in a straightforward and direct manner. There would have been no need for the elaborate process it in fact endorsed. Finally, the settlement itself states that the cost of market resources should only "be one component in determining utilities avoided costs," and then only to the extent utilities are actually relying on them. Settlement Stipulation at 4-5.

Q. THEN HOW DID THINGS COME TO THIS PASS THAT AVISTA CAN CLAIM THAT ITS AVOIDED COSTS ALWAYS EQUAL PROJECTED MARKET PRICES?

A. The evidence will support either of two alternative explanations. The first is that this is the unfortunate and unintended consequence of a Commission decision that the utility has followed in good faith. The more cynical view is that the Commission's order left Avista an opportunity it has exploited to subvert the Commission's intent.

Q. HOW DID YOU ARRIVE AT THESE ALTERNATIVES?

A. In Order 26576 the Commission was forced to decide one critical issue the parties could not resolve in the Stipulated Settlement. The utilities wanted the maximum contract term shortened from 20 years to five years, arguing that they did not intend to construct or acquire new long term generating resources. See Order No. 26576 at 3-5. Staff and the QF developers continued to support 20 year contracts. Ultimately the Commission adopted the utilities' arguments and shortened the mandatory contract length to five years. Order No. 26576 at 6-7.

This finding effectively opened the door to unzipping all the painstaking work that went into the Stipulated Settlement. In Avista's case, it simply assumed, <u>for avoided cost purposes</u>, that: (1) market prices can be reasonably forecast for five years, (2) all short term resource needs of 5 years or less will be met by market purchases and (3) existing high cost resources will be displaced by market purchases rather than the avoided cost resource, and "*Voila*!" Avoided costs automatically equal projected market prices no matter what happens to all the other variables in the avoided cost model.

Q. YOUR ANSWER EMPHASIZES THE FACT THAT AVISTA MADE THIS ASSUMPTION "FOR AVOIDED COST PURPOSES." WHY?

A. I can't say whether Avista really believed in 1996 that the market would provide all future resource needs. In any case, those utilities that believed in total reliance on the market as a prudent resource acquisition strategy were disabused of that notion by the events of 2000-2001. By early 2001 Avista had clearly abandoned any market reliance strategy and begun the construction of Coyote Springs II, Boulder Park, and a number of other smaller generating projects. But for avoided cost purposes, Avista made no such change in planning even though its IRP, which is supposed to drive avoided cost calculations, clearly recognizes the need for, and construction of, new resources.

Q. WHY IS THIS OBJECTIONABLE?

A. In the first place, it violates the express terms of the Stipulated Settlement that Avista signed in 1996. That settlement authorized the utilities to select their own variables in their avoided cost calculations as long as those "values and assumptions fall within a reasonable range." Stipulated Settlement at 5. But the settlement further provided that utilities "will be required to analyze their own resources on an equal footing with QF resources." *Id.* Thus, market prices are an acceptable component of the avoided cost determination only if they are in fact the resource of choice for the utility. *Id.*

It is obvious that when Avista made the decision to construct Coyote Springs II and Boulder Park it abandoned market purchases as the resource of choice. It is equally obvious that Avista did not analyze those resources in anything like the manner in which it is evaluating Potlatch's cogeneration. There is clearly nothing "equal" or fair about a situation in which Avista is constructing plants that will surely come in at an all-in cost roughly 50% to 100% higher than Avista's offer to Potlatch.

Moreover, this situation is a violation of both the letter and spirit of PURPA. The whole point of PURPA is to insure that QFs receive payments equivalent to the cost that their generation avoids. If a utility is constructing base load plants, as Avista is, then the avoided cost should bear a strong relationship to the cost of those plants. Again, the Commission's adoption of the SAR avoided costs in GNR-E-02-1 underscores this point.

Q. HOW DO YOU PROPOSE THAT THE COMMISSION RECTIFY THIS SITUATION?

A. First, I recommend that the Commission abandon or revoke Order No. 26576. It was promulgated at a time when the utility world looked much different than it does now and, at least as administered by Avista, it obviously does not produce an accurate calculation of avoided costs. At the very least, I recommend that the Commission adopt a 20 year contract limitation for large QFs for the same reasons that persuaded it to adopt a maximum contract length of 20 years for QFs of less than 10 megawatts.

Second, the Commission should make it clear that avoided costs cannot be equated to market prices, except possibly for very short term needs one or two years in the future.

Q. WHY IS AN EXPLICIT RESTRICTION ON THE USE OF MARKET PRICES NECESSARY?

A. In the first place, market prices are meaningful only if the market is liquid, transparent and unconstrained. With the collapse of Enron, and the near death experience of Dynergy and a host of others, western power markets are arguably too thinly traded to meet these criteria, particularly over the longer term such as five years. Even if you can determine the most recent price for a 5 year, 50 megawatt contract there is no assurance that another contract could be executed at the same price.

Perhaps more important, if one uses market prices as a surrogate for avoided costs, then those prices should be adjusted upward to reflect market risks. As we have all learned from recent experience, the risks of going long or short in the market are not symmetrical. If I buy $50 worth of power the most I can lose on the transaction is $50, even if the market price goes to zero. But if I go short and depend on the market to meet my future needs, there is no limit to the price I could be required to pay, as Avista found out when it was forced to pay in excess of $300/mwh in 2000-2001. Any utility that plans on meeting its needs by market purchases must take this risk into account, and so should any avoided cost calculation that uses market prices. Unfortunately, there is no reliable way to quantify the present value of this risk in the Prosym model, and utilities that have resorted to using financial derivatives to attempt to limit market risk have generally met with disastrous results. That is in fact why Avista is constructing generating plants that exceed the supposedly efficient market-clearing price determined by the model.

Q. HOW THEN DO YOU PROPOSE THE COMMISSION DETERMINE THE PRICE FOR POTLATCH'S COGENERATION?

A. One possibility is that the Commission could modify the Prosym model in an attempt to determine Avista's true avoided costs. But as I pointed out earlier, the fact that the model is proprietary and therefore unavailable for detailed analysis, means that one has to make educated assumptions about the nature of the required modifications. Moreover, I cannot say with assurance that the necessary changes can, as a practical matter, be accomplished without violating the integrity or functionality of the model.

Q. CAN YOU LIST SOME OF THE CHANGES THAT WOULD BE REQUIRED TO ENABLE THE MODEL TO DETERMINE AVISTA'S TRUE AVOIDED COSTS?

A. Obviously the first adjustment would be to eliminate the market supply cost curve from the model. This would probably require the substitution of some other type of historical market data to capture the cost of opportunity sales and purchases, but it is not immediately apparent to me how this consideration could be included without turning the model back into a market driven exercise. In addition, we would have to estimate variable operating and maintenance costs for Coyote Springs II and Boulder Park with little or no actual operating data to go on. This is necessary because, with market pricing eliminated, both of these resources would be key drivers of the dispatch simulation and avoided cost calculation. Environmental costs associated with the operation of one of the Company's peakers would also have to be added, probably in the form of external calculations.

Most important, because the model is essentially an energy only calculation, we would have to add a credit or adder to reflect the value of capacity and the risks posed by the lack of sufficient capacity, and this calculation would probably have to be devised outside the model and then somehow reinserted into the modeling process. Without this adjustment, the model will always underestimate the true avoided costs. Finally, I suspect that if I had access to the model itself I would find that additional changes are necessary, and that the changes I have proposed necessitate still more adjustments to preserve the model's functionality.

Q. ARE YOU IN FACT RECOMMENDING THAT THE COMMISSION USE THE MODEL ADJUSTED IN THE FASHION YOU HAVE SUGGESTED?

A. I cannot even assure the Commission it is physically possible to correct the model in the manner I have suggested. The Prosym model was designed to value a resource acquisition only in comparison to market prices. Once we decide, as Avista quite sensibly has, that market purchases are not a reasonable substitute for physical generating resources, the model must be completely rebuilt in order to furnish any sort of intelligible information about a given resource's value. Moreover, the most crucial components of this rebuilding process (e.g, Coyote Springs' variable costs and the appropriate capacity credit) would have to be developed outside the model, so in the end the results would hinge on the results of a debate about the appropriate value of these elements. Under these circumstances, I do not believe that the required effort is even remotely worth the dubious results that might be achieved by altering the model to fit Avista's current situation.

Q. IS THERE AN ALTERNATIVE METHOD THE COMMISSION COULD USE TO CALCULATE AVISTA'S AVOIDED COSTS?

A. Yes. This case presents a unique opportunity to determine Avista's avoided cost with great accuracy. When Avista first began construction of Coyote Springs it planned on receiving approximately 280 megawatts of capacity and energy from that plant. Unfortunately, Avista's financial condition was then devastated by the huge purchase power costs it incurred in 2000 and 2001, so it was forced to sell half of Coyote Springs to bolster its balance sheet and curb cash expenditures. This leaves Avista 140 megawatts short of the resource needs it identified as prudent and for which it was, and presumably still is, willing to "purchase" at Coyote Springs' all-in cost per mwh. If Potlatch provides a portion of this 140 megawatts at a price equivalent to Coyote Springs' cost, both Avista and its ratepayers would be indifferent to the result and PURPA's requirements would be satisfied.

Q. DO YOU KNOW WHAT THE COST OF COYOTE SPRINGS' GENERATION WILL BE?

A. I know what the preliminary cost estimates were, but I suspect they will turn out to be lower than actual because of construction problems at the site. Unfortunately, I am not at liberty to divulge even the preliminary estimated costs because they were furnished as confidential material in another proceeding. Under these circumstances, the only way to immediately use Coyote Springs' actual costs would be to set an interim avoided cost rate for Potlatch and then adjust it retroactively to Coyote Springs' costs when the plant comes on line.

Q. SHOULD THE COMMISSION IMMEDIATELY UNDERTAKE AN INDEPENDENT INVESTIGATION OF COYOTE SPRINGS' COST IN ORDER TO DETERMINE AVISTA'S AVOIDED COST?

A. Fortunately, I don't believe that is necessary. The Commission has just recently completed a thorough reexamination of the cost of constructing and operating a natural gas generating facility in connection with its determination of avoided costs for projects of 10 megawatts or less. I believe the Commission could with complete confidence use the costs determined in that case as the basis for an avoided cost determination in this proceeding.

Q. YOU STATED THAT THE PRICES PUBLISHED IN CASE NO. GNR-E-02-1 COULD BE USED AS "THE BASIS" FOR AVOIDED COSTS IN THIS CASE. DO YOU HAVE ANY REASON TO BELIEVE THE COMMISSION WOULD AGREE TO THIS RECOMMENDATION?

A. Yes. Approximately three weeks ago, on March 28, 2003, the Commission issued Order No. 29216 in Case No. GNR-E-03-1. In that case the Independent Energy Producers of Idaho filed a petition requesting that the Commission increase from 10 MW to 30 MW the size at which a qualifying cogeneration or small power production facility is entitled to published avoided cost rates. The Commission rejected the proposal that larger QFs should be entitled to published rates as a matter of right, but went on to say:

> The Commission notes that QFs greater than 10 MW are not precluded from contacting an electric utility and individually negotiating a power purchase agreement. That has long been the contract procedure for large QFs. <u>The starting point for such negotiations under the approved methodology is the established posted rate.</u> Should a utility fail to negotiate in good faith with a qualified QF, a complaint can be filed with this Commission.

Order No. 29216 at 3. I recommend that the Commission follow exactly that procedure in this case.

Q WHAT ARE THE CURRENT POSTED RATES FOR AVISTA?

A. As I stated earlier, the rate for a 5 year contract term, which seems to be acceptable to both parties, is $43.3/mwh. A full copy of Avista's posted SAR rates is attached as Exhibit 5.

Q. IF THESE RATES ARE THE "STARTING POINT" FOR NEGOTIATIONS, SHOULD THEY BE ADJUSTED IN SOME FASHION?

A. Yes. There are at least four factors that argue for an upward adjustment to the posted rates for Potlatch. First, there is the matter of sheer size. Potlatch's cogeneration facility is capable of providing 80 megawatts of capacity and energy on a near continuous basis. A purchase of this magnitude provides obvious economies of scale as compared to the purchase of similar quantities of energy from a number of producers.

Second, Potlatch's plant has a demonstrated history of safe, reliable and efficient generation and delivery of power to Avista. Most other proposed QFs will be new facilities that are subject to all the inherent uncertainties and risks associated with an untried and untested startup. Moreover, the interconnection facilities between Avista and Potlatch, including the necessary metering equipment and related items, are already in place and the parties already have 10 years of cooperative operating experience in the simultaneous sale and purchase of power. All of these factors tend to decrease Avista's costs.

Third, as a true cogenerator, Potlatch offers Avista a unique and valuable measure of risk protection that no other resource, including Avista's own plants, can provide. A hydroelectric facility can be washed out by floods, a wind generator can be disabled by storms, and a utility steam generator can be unusable for extended periods as a result of catastrophic accidents. In each case, the utility purchasing the lost plant's output may be forced to scramble for replacement power supplies at inconvenient times. But Potlatch's cogeneration is an integral part of its mill operations, and it is difficult to imagine that all four of Potlatch's cogeneration units would be completely off line unless the mill was also shut down. In that event, Avista would not be faced with a sudden need to find replacement resources because the loss of the Potlatch mill load would exceed the disabled generating capacity. Avista might then find itself with some extra energy available for sale but it would not face the risks associated with replacing lost resources.

Fourth, and most important, Potlatch is entitled to an addition to the posted cost rates to reflect the fact that Potlatch's cogeneration provides Avista with very significant savings in capital expenditures on transmission. It is common knowledge that, without Potlatch's cogeneration, Avista would have to upgrade its transmission system in order to provide reliable service to the Lewiston/Clarkston valley. Avista's avoided investment in transmission does not fit within the normal avoided cost calculation, but this is a unique situation. Given the magnitude of Avista's avoided transmission costs, it would be both unrealistic and inequitable to omit these costs from Potlatch's rates.

Q. HAVE YOU QUANITIFIED THE ADDED VALUE TO POSTED AVOIDED COST RATES FOR THE FACTORS YOU HAVE JUST DICUSSED?

A. No, not precisely. If we are successful in discovery requests, I may be in a position to more formally address this in rebuttal or at the hearings.

Q. CAN YOU OFFER AN ESTIMATE OF THIS ADDED VALUE?

A. Yes, I estimate that the additional savings from avoiding the line losses of an external resource such as Coyote Springs II, and avoidance of major internal-transmission expenditures to replace the system stability provided by Potlatch generation to be roughly equivalent to a 10% increase in the avoided cost rates. I conclude therefore that a rate of 47.6 mills/kwh to Potlatch is fair and reasonable.

In the alternative, Potlatch would agree to an interim rate of $47.60/mwh until Coyote Springs is brought on line. At that point, the Commission would calculate Coyote Springs' all-in costs and adjust Potlatch's rates to those costs. Potlatch would take the risk that Coyote Springs might come in lower than Potlatch's rate. This proposal has the benefit of matching Potlatch's rate to the exact plant that Potlatch is deferring and it holds the ratepayers completely harmless.

Q. ARE THERE ANY OTHER RELEVANT FACTORS THAT THE COMMISSION SHOULD CONSIDER IN THIS CASE?

A. Yes. Since the expiration of the prior Avista/Potlatch contract on December 31, 2001, the lack of a power sales contract has forced Potlatch to generate into its own load. By any measure, this is an undeserved windfall for Avista because Avista effectively gets the benefit of Potlatch's generation without paying for it. But this is a dangerous game for Avista's ratepayers. Someday market prices will spike up to a sufficiently high level to entice Potlatch to sell its generation to a third party. At that point, Avista will have to buy replacement power in the same high priced market. Ninety percent of the cost of that replacement power will flow straight through Avista's PCA, resulting in a direct and immediate rate increase for Idaho ratepayers. Avista itself will absorb only ten percent of that cost. Given the windfall it is receiving from the free use of Potlatch's power in the interim, this is a small risk for Avista to run. But the stakes for the ratepayers are far higher and the potential for loss much more severe.

Q. WOULD YOU PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS?

A. I recommend that the Commission adopt as a point of departure the "SAR" avoided cost concept it established in the recent Case No. GNR-E-02-1 and increase those avoided cost rates for Potlatch for reasons I explained earlier in my testimony. The five- year SAR posted rate beginning in 2004 is approximately $43.30/mwh. With the additions I have proposed, Potlatch's rates would become $47.60/mwh. Alternatively, I recommend that the Commission adopt the $47.60 rate as an interim rate until Coyote Springs' costs can be determined, at which point Potlatch's rate would be adjusted to equal Coyote Springs' costs.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that on the 25th day of April, 2003, I caused to be served a true and correct copy of the foregoing by the method indicated below, and addressed to the following:

Jean Jewell
Idaho Public Utilities Commission
472 W. Washington Street
P.O. Box 83720
Boise, ID 83720-0074
__ U.S. Mail __ Fax _x_ By Hand

Scott D. Woodbury
Idaho Public Utilities Commission
472 W. Washington
P.O. Box 83720
Boise, ID 83720-0074
__ U.S. Mail __ Fax _x_ By Hand

David J. Meyer
Senior Vice President and General Counsel
Avista Corporation
1411 E. Mission Ave.
Spokane, WA 99220
_x_ U.S. Mail __ Fax __ By Hand

R. Blair Strong
Paine, Hamblen, Coffin, Brooke & Miller LLP
717 West Sprague Avenue, Suite 1200
Spokane, WA 99201-3505
_x_ U.S. Mail _x_ Fax __ By Hand

Tina Smith
Tina Smith

DENNIS E. PESEAU

President
Utility Resources, Inc.

EDUCATION

Claremont Graduate School	Ph.D. Economics, 1977 M.A. Economics, 1971
California State University (Chico)	B.A. Economics, 1969

INDUSTRY AND GOVERNMENT EXPERIENCE

Zinder Companies, Inc.	Senior Vice President
Oregon Public Utility Commissioner	Senior Economist
Southern California Edison Company	Economist

Dr. Peseau has consulted on numerous technical, legal and administrative economic, engineering and financial topics for over fifteen years. He currently heads a firm which is engaged entirely in technical, mathematical and computer modeling of large scale economic problem solving for litigated, disputed or otherwise contentious issues. Members of the firm are involved almost constantly in the development and presentation of economic issues in a manner which can be understood by persons not expert in these areas.

Dr. Peseau has personally testified in various administrative and civil proceedings on more than one hundred occasions.

TESTIFIED OR PREPARED STUDIES BEFORE STATE AND FEDERAL AGENCIES IN:

Alaska	Maryland	New York
California	Minnesota	Oregon
Colorado	Montana	Virginia
Idaho	Nevada	Washington
		Washington, D.C.

SELECTED CONSULTING EXPERIENCE

- Anti-Trust, Economic Evaluation and Other Civil Suits

Western Cities Broadcasting, Inc. vs. Eldorado Communications. District Court, Jefferson County, State of Colorado.

Schmidt-Tiago vs. State of Colorado. Conducted extensive econometric and statistical analysis and direct testimony to rebut liability and damage claims by plaintiffs in bid rigging anti-trust case.

Asphalt Paving vs. State of Colorado. Conducted extensive econometric and statistical analysis and direct testimony to rebut liability and damage claims by plaintiffs in bid rigging anti-trust case.

Peter Kiewit Construction vs. State of Colorado. Conducted extensive econometric and statistical analysis to rebut liability and damage claims by plaintiffs in bid rigging anti-trust case.

State of Oregon vs. Santiam Canyon Lumber Companies. Develop modeling methods for plaintiffs to estimate damages from alleged bid-rigging practices.

UNOCAL vs. Pacific Gas & Electric, U. S. District Court, Central District of California. Develop modeling methods to estimate damages in complaint for violation of federal antitrust law; breach of contract.

Oregonian Paper Dealers vs. Oregonian Newspaper. Develop modeling methods for plaintiffs to estimate damages from alleged price setting to dealer groups.

PPC vs. Johnson, before Judge Panner, Federal Court Case in Oregon. Prefiled testimony ordered by Judge Panner on various federal Northwest Power Planning Act issues.

Colorado Interstate Gas Companies vs. Martin Exploration Management Corp., District Court of the County of El Paso. Damage calculations in gas contract price case.

Lifetime earnings analysis and job interview appraisal for wrongful termination, discrimination suit.

Analysis regarding appropriate settlement levels in take-or-pay suit.

- Power Economics

Conducted reserve and reliability studies for the Northwest Power Planning Council.

Developed an optimal capacity expansion model for electric power systems to analyze reliability, reserve margins, hydro dispatch and costs of system growth.

Developed procedure to value electric energy from cogeneration projects and economic trade-offs of electric and process pressure steam.

Testified before Bonneville Power Administration in 1982, 1983, and 1985 rate cases

-Cogeneration and Avoided Cost Estimation

Developed, sponsored utility system models of groups of prospective CSPPs to estimate avoided costs in Alaska, Oregon, Idaho, California, Washington, Virginia, Maryland and District of Columbia.

Conducted economic and financial feasibility studies and developed models for same for several prospective CSPPs.

Testified on avoided costs, contract terms, cost classification and seasonal rates for CSPPs in several jurisdictions. Wrote discussion papers on the value of geothermal development in the Pacific Northwest for U.S. Secretary of Energy and Administrator of Bonneville Power Administration.

- Rates, Rate of Return and Regulation

Co-developed rate and marginal cost estimation models and assessed rate spread implications for several major U.S. electric utilities. Testified in PURPA and general rate cases on these matters.

Developed a series of energy and revenue forecasting computer models for Southern California Edison Company.

Developed cost of capital and economic feasibility testimony in support of an incentive rate of return for a major natural gas pipeline.

Developed a model based on capital asset pricing for use in cost of capital testimony for major U.S. utilities. Testified recently in over twenty cases.

Conducted a capital s tructure study for Pacific Northwest Bell Telephone Company.

- Finance

Developed a rate of return, cost of capital and capital structure study and sponsored testimony on these subjects in several regulatory jurisdictions.

Conducted a study assessing the financial impact on ratepayers, utility companies and a municipality of dual jurisdiction as proposed in a large Northwest city.

Assisted the Arthur D. Little team to analyze the demand forecasting and financial modeling of Portland General Electric Company.

PUBLICATIONS

Size, Growth and Profits, and Executive Compensation in the Large Corporation (with D. Smyth and W. Boyes). (London, The Macmillan Press, and New York, Holmes and Meier, 1975).

"On the Relationship Between Executives' Compensation, Sales, and Profits," Atlantic Economic Journal, Vol. VII, No. 2, July 1979.

"A Comment on the Use of CAPM in Public Utility Rate Cases," Financial Management Journal, Vol. 7, No. 3, Autumn 1978.

"The Measurement of Firm Size: Theory and Evidence for the United States and the United Kingdom" (with D. Smyth and W. Boyes), Review of Economics and Statistics, Vol. LVI, No. 1, February 1975.

"On Optimization in Models of Urban Land Use Densities" (with W. Boyes), Journal of Regional Science, Vol. 13, No. 1, 1973.

PAPERS AND CONFERENCE PRESENTATIONS

Guest lecturer, Executive Seminar, "Regulated Utility Cost of Equity and the Capital Asset Pricing Model," Colgate Darden Graduate School of Business, University of Virginia, 1979.

"Shorter Term Stability and Predictability of Parameters of Capital Asset Pricing with Implications for Regulated Utilities," presented to the Western Economic Association Conference, Las Vegas, 1979.

"Rate Base Valuation as a Determinant of Risk in the Electric Utility Industry," presented to the Financial Management Association, Seattle, 1977.

"Resource Allocation and Rate of Return Regulation in Electric Power Generation: Capital Surplus or Shortage?", presented to the Western Economic Association Conference, San Diego, 1975.

"Resource Allocation in an Industry Regulated by Rate of Return," read to the UCLA Graduate School Seminar on the Economics of Regulation, 1975.

4/03	Before the PSC of Nevada On behalf of Southern Nevada Water Authority	Docket No. 02-11021
7/02	Before the Idaho PUC On behalf of Idaho Power Company	Case No. GNR-E-02-1
5/02	Before the PSC of Nevada On behalf of Southern Nevada Water Authority	Docket No. 02-4037
2/02	Before the PSC of Nevada On behalf of Southern Nevada Water Authority	Docket No. 01-11029
1/02 2/02	Before the PSC of Nevada On behalf of Southern Nevada Water Authority	Docket No. 01-10001 Docket No. 01-10002
4/01	Before the Idaho PSC On behalf of Potlatch Corp.	Case No. AVU-E-01-5
1/01	Before the PSC of Nevada On behalf of Southern Nevada Water Authority	Docket No. 00-10014 Docket No. 00-10015
9/00	Before the PSC of Nevada On behalf of Southern Nevada Water Authority	Docket No. 00-6063
6/00	Before the PUC of Oregon On behalf of Industrial Customers of Northwest Utilities	Docket No. UM-967
12/99	Before the Idaho PSC On behalf of Potlatch Corp.	Case No. AVU-E-99-6
8/99	Before the PSC of Nevada On behalf of Southern Nevada Water Authority	Docket No. 99-4005
5/99	Before the Idaho PUC On behalf of Industrial Customers	Case No. IPC-E-99-3

	of Idaho Power	
4/99	Before the Idaho PUC On behalf of Potlatch Corp.	Case No. WWP-E-98-11
9/98	Before the Nevada PSC On behalf of Southern Nevada Water Authority	Docket No. 98-7023
8/98	Before the PSC of Nevada On behalf of Southern Nevada Water Authority	Docket No. 97-7030
5/98	Before the Idaho PUC On behalf of Industrial Customers of Northwest Utilities	Case No. IPC-E-97-12

Potlatch

October 2, 2001

Potlatch Corporation
Idaho Pulp and Paperboard Division

803 Mill Road
P.O. Box 1126
Lewiston, Idaho 83501-1126
Telephone (208) 799-1561

Mr. Douglas Young
Avista Utilities
1411 East Mission
Spokane, Washington 99220

Subject: Avoided Cost Calculation

Dear Mr. Young:

Potlatch Corporation is in the process of determining the most beneficial way to sell the output from its generation facilities at the expiration of the current contract between Potlatch and Avista at the end of this year. One option is to sell Potlatch's generation to Avista Utilities (Avista) at avoided cost. Therefore, we are requesting that Avista provide us with the avoided cost amount for Potlatch's generation – the amount Avista will pay to avoid generating power or purchasing power at market if it could instead obtain such power from Potlatch's facilities.

It is our understanding that the avoided cost methodology for projects larger than one megawatt has been developed and is approved by the Idaho Public Utilities Commission (IPUC). We request that Avista perform all calculations, and fulfill all requirements, as described in the approved calculation methodology. It is also our understanding that the calculation methodology that Avista is required to use is described in Case No. IPC-E-95-9. If this is not your understanding, please advise as to the methodology Avista intends to use for calculating the avoided cost and Avista's rationale for using an alternative methodology.

The IPUC staff contends that, under the approved methodology, the utility is obligated to respond to a request for an avoided cost calculation within 30 days. We would greatly appreciate an earlier response if possible.

IPUC staff recommends a meeting between the developer (Potlatch) and Utility (Avista) to discuss details of the project and details of the avoided cost calculation. It is Potlatch's desire to conduct this meeting at your earliest convenience. Potlatch suggests 10:00 a.m. October 12, 2001, in Spokane, Washington, as a potential date and time for this initial meeting.

Per the approved cost calculation methodology we are providing the following information.

1. The Developer is:

   Potlatch Corporation
   601 West Riverside Ave.
   Suite 1100
   Spokane, WA 99201

2. Proof of QF Status:

   Potlatch has four (4) separate Qualified Facilities

   1. QF83-142-000 - A cogeneration facility rated 11,188 kVA @ 0.8 PF
   2. QF83-144-000 - A cogeneration facility rated 12,500 kVA @ 0.8 PF
   3. QF83-143-000 - A cogeneration facility rated 41,600 kVA @ 0.85 PF
   4. QF92-67-000 - A cogeneration facility rated 66,916 kVA @ 0.95 PF

3. Project location:

   Potlatch Corporation
   803 Mill Road
   P.O. Box 1126
   Lewiston, ID 83501

4. Project size, including ambient conditions for this rating:

   The project generating size based upon available steam to the four turbine generators is a maximum of 85 MW under all ambient conditions.

5. Capacity factor and proposed time shape of production:
   Potlatch will provide proposed capacity levels after our initial meeting.

6. Fuel source and mode and route of delivery:

   A combination of wood waste, black liquor, and natural gas are used in various combinations to supply steam to power and recovery boilers. Wood waste is a by-product of on-site process production and is also delivered by truck. Black liquor is a by-product of the pulp-making process. Natural gas is delivered from various sources via a natural gas pipeline and then through Avista's distribution line.

7. Whether fuel supply is firm or non-firm and whether there are any constraints affecting its availability or dependability:

   Wood waste and black liquor are dependent on process plant production. Natural gas is dependent on the availability of supply and appropriate transportation capability. The reliability of the plant generation is anticipated to be the same as historically demonstrated.

8. Proposed contract term (final term – length and timing – to be subject to negotiations):

   The term is negotiable, but no less than five years.

9. On-line month and year:

   This is an existing facility that has sold part of its generation output to Avista under contract for nearly the past 10 years. This contract expires at 12:00 a.m., January 1, 2002, making the above-referenced output available at that time.

10. Maintenance schedule:

    Maintenance schedule is determined by plant process maintenance. Historically, this has been scheduled in advance with Avista, and Potlatch proposes to use similar procedures in the future. No difference is anticipated from what has been historically demonstrated.

11. Other factors affecting operations:

    Operations are expected to remain the same as historically demonstrated.

12. Wheeling utility or utilities between point of interconnection and point of delivery:

    None.

13. Expected delivery per months during heavy and light load hours:

    Delivery of energy is expected to be relatively constant over a 24-hour period, as historically demonstrated.

14. Guaranteed minimum capacity:

    The minimum capacity scenarios are described in item #5.

Thank you for your anticipated prompt response to this request.

Sincerely,

POTLATCH CORPORATION

Howard Ray
Engineering/Process Control Manager

c: Randy Lobb - IPUC
Conley Ward, Esq.

Power Sale Key Assumptions

Sale to AVA

- January 2002 through December 2006 term
- 50 MW flat
- Potlatch carries reserves for sale
  - 7% (3.5% spin/3.5% non-spin)
  - may require 2% spinning reserve requirement (will check with transmission group)
  - where AVA carries reserves, value is less
- financially-firm
  - i.e., in hours where there is no generation, Potlatch will compensate the Company at its cost of replacement power, including transmission to AVA's system
  - if Potlatch will not guarantee deliveries, value is substantially less

Sale to Market

- same terms as above
- requires purchase of AVA transmission, including losses, and reserves
  - approximately $3.11/MWh, including a load following charge
    - price of losses increase as market increases
- transmission to other systems not quantified
  - will lower value to Potlatch

Assumptions

Price Forecasts: 10/12/2001 Forward Curves

Month	Mid-C Electricity HLH ($/MWh)	Mid-C Electricity LLH ($/MWh)	Mid-C Electricity Flat ($/MWh)	Rathdrum Natural Gas ($/dth)	Month	Mid-C Electricity HLH ($/MWh)	Mid-C Electricity LLH ($/MWh)	Mid-C Electricity Flat ($/MWh)	Rathdrum Natural Gas ($/dth)
Jan-02	35.25	28.20	32.22	3.010	Jan-06	39.17	31.33	35.80	3.607
Feb-02	33.75	27.00	30.85	2.997	Feb-06	37.50	30.00	34.27	3.493
Mar-02	30.00	24.00	27.42	2.937	Mar-06	33.33	26.67	30.47	3.361
Apr-02	28.00	22.40	25.59	2.829	Apr-06	31.11	24.89	28.43	3.191
May-02	25.00	20.00	22.85	2.854	May-06	27.78	22.22	25.39	3.191
Jun-02	29.25	23.40	26.73	2.898	Jun-06	32.50	26.00	29.70	3.223
Jul-02	40.00	32.00	36.56	2.936	Jul-06	44.44	35.55	40.62	3.273
Aug-02	48.00	38.40	43.87	2.972	Aug-06	53.33	42.67	48.75	3.307
Sep-02	43.50	34.80	39.76	2.967	Sep-06	48.33	38.67	44.18	3.320
Oct-02	34.50	27.60	31.53	2.991	Oct-06	38.33	30.67	35.04	3.277
Nov-02	36.00	28.80	32.90	3.176	Nov-06	40.00	32.00	36.56	3.442
Dec-02	36.00	28.80	32.90	3.381	Dec-06	40.00	32.00	36.56	3.607
Average	34.94	27.95	31.93	2.996	Average	38.82	31.05	35.48	3.358

Transmission: $1.40/kW-month, 3% losses ~$1.98/MWh

Reserves: 3.5%/3.5%/2.0% spin/supplemental/load following @ $8.94/kW-month ~ $1.14/MWh

Base Case: Potlatch sells off system, purchasing losses, reserves, and transmission
Avista serves entire load at Schedule 25 rates

Flat Sale Case: Potlatch sells 50 MW (flat, year-around, with liquidated damages) as PURPA to AVA
Avista serves entire load at Schedule 25 rates
$67.8 million portfolio benefit & 2,189,540 MWh = $30.95/MWh net value of power

PROSYM™

Market Simulation Engine

Energy enterPrise software

Business Solutions
for **Energy Supply Chain** Management

RETAIL DATA MANAGEMENT

LOAD FORECAST

PRICE FORECAST

GENERATION EVALUATION

GENERATION OPERATIONS

WHOLESALE TRADING

RISK ANALYSIS

PORTFOLIO OPTIMIZATION

ENERGY SCHEDULING

ENERGY SETTLEMENTS

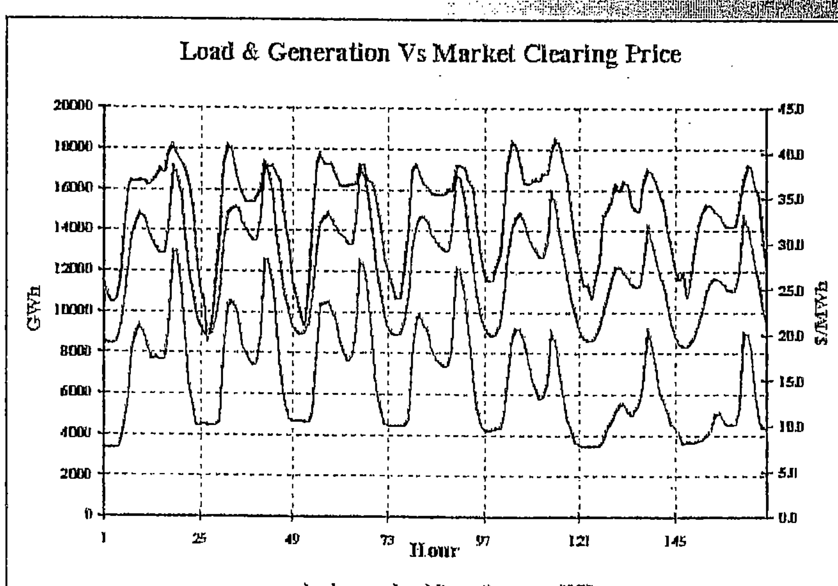
Electric markets worldwide are rapidly transforming from regulated industries to environments characterized by aggressive competition and customer choice. Wholesale energy is now sold, traded, and purchased as an unbundled commodity. Forecasting market-clearing prices, acquiring and scheduling supply resources in response to these prices, and developing a fundamental in-depth understanding of the market dynamics, are mission-critical tasks for any entity actively involved in the wholesale energy market.

Henwood Energy Services, Inc. (Henwood) has developed a suite of Business Solutions for energy supply chain management. **Henwood's** PROSYM™ product provides Price Forecasting, Generation Evaluation, Generation Operations, Risk Analysis, and Portfolio Optimization functions.

Product Description

PROSYM performs a detailed fundamental simulation of the electric wholesale market on an hour-to-hour basis. Electric production is modeled at the generation unit level while system loads and transmission constraints are modeled on an hourly basis. PROSYM computes market clearing prices and generation production for user-defined transmission zone(s).

PROSYM reflects the specific market rules for any region that is being modeled – whether it is the United Kingdom, Australia, Singapore, Alberta, California, or anywhere else in the world. As a result of its extensive ability to incorporate specific regional rules, PROSYM has up to an 80 percent market share in deregulated markets worldwide.



Benefits

PROSYM is a defensible and proven market modeling system, and the leading hourly simulation solution in the world for electric wholesale markets. PROSYM is currently being used by more than 120 companies on five continents.

PROSYM's robust flexibility allows the user to model scenarios ranging from the specific design details of a generation unit to assessing the impacts of market restructuring legislation.

PROSYM provides a more defensible market simulation result than any of its competing products. For the past 15 years, the model has been proven in the most exacting forums such as utility rate filings, litigation hearings, and bond financings.

PROSYM can be used in a stand-alone mode or can be further expanded with any combination of 10 modules that have been specifically designed by Henwood staff to solve complex or unique business issues.

Product Features

The extensive capabilities of PROSYM cause it to be the analytical tool of choice for understanding wholesale markets worldwide. These features include:

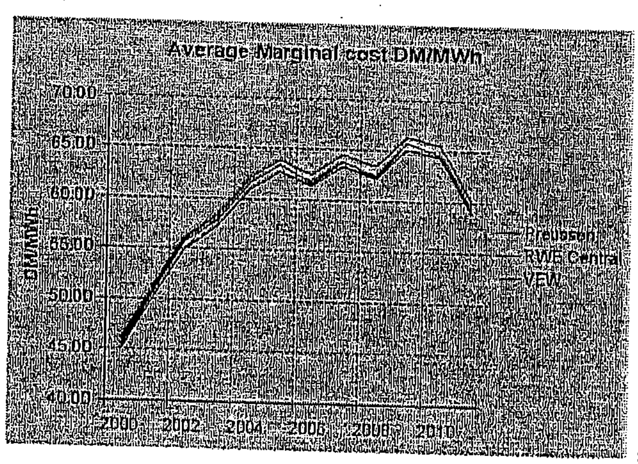
- Detailed market simulations from one day to twenty years
- Advanced hourly commitment and dispatch optimization
- Cost, bid, emission, or price-based dispatching capability
- Direct modeling of stochastic drivers and their correlations: forced outages, energy market and reserve market prices, emission prices, fuel prices, hydro energy and load
- Generating asset profit maximization in competitive markets
- Zonal market-clearing prices and congestion charges computed on an hourly basis
- Bid-based market simulations based on region-specific pool rules
- Zonal constraints such as minimum generation and multiple operating reserve criteria are enforced
- Detailed representation of performance, cost, and constraint characteristics of physical and financial supply resources
- Direct modeling of significant chronological constraints such as ramp rates and minimum up and down times
- Fuel contract and pipeline constraint optimization
- Direct modeling of start-up costs and fuel burn as a function of off-time

Business Applications

PROSYM performs detailed simulations of energy markets worldwide. It is used for forecasting wholesale electric prices, evaluating generation assets, energy transactions, and short-term unit commitment and dispatch decisions.

PROSYM, in tandem with its supplemental modules, provides regional simulation capabilities unparalleled in the industry. These applications are critical if a company is:

- Evaluating its competitive position and identifying attractive market opportunities
- Considering the acquisition or divestiture of an electric generation asset and need to determine the value of the asset under competitive market conditions
- Financing a major electric generation investment in a competitive power market
- Performing stranded cost recovery evaluation
- Developing forward-price curves or generation operating budgets
- Forecasting energy, capacity and ancillary service prices
- Performing transaction evaluation, and transmission congestion analysis
- Evaluating regional emission impacts of generating facility additions



Henwood
2710 Gateway Oaks Drive Suite 300N
Sacramento, CA 95833
Tel: (916) 569-0985
Fax: (916) 569-0999
Sacramento • Atlanta • Australia • London

Energy enterPrise software

Market Analytics
- MarketPlace™
- MARKETSYM™

Risk Analysis
- RiskReporter™
- RISKSYM™
- Theo™

Generation Operations
- PROSYM™
- OPSYM™
- MAINSYM™

Wholesale Operations
- TradeManager™
- WebScheduler™

Retail Operations
- RACM™

Henwood Consulting

Henwood's Consulting Services:
- Strategic Planning
- Power Market Analysis
- Power Business Solutions
- Retail Business Solutions

Henwood eBusiness

Henwood's eBusiness Applications
- MarketWatch
- GenReporter
- NextGen
- Hydro Forecasts

Email: sales@hesinet.com
www.henwoodenergy.com

Table 1
Potlatch Analysis Forward Curve Summary

	Average				2002				2003			
	Mid-C			NYMEX	Mid-C			NYMEX	Mid-C			NYMEX
Month	HLH	LLH	Flat	Gas	HLH	LLH	Flat	Gas	HLH	LLH	Flat	Gas
Jan	38.30	30.64	35.00	3.477	35.25	28.20	32.22	3.010	38.74	30.99	35.41	3.501
Feb	36.67	29.33	33.51	3.387	33.75	27.00	30.85	2.997	37.09	29.67	33.90	3.406
Mar	32.59	26.07	29.79	3.271	30.00	24.00	27.42	2.937	32.97	26.38	30.13	3.296
Apr	30.42	24.34	27.80	3.121	28.00	22.40	25.59	2.829	30.77	24.62	28.13	3.160
May	27.16	21.73	24.83	3.127	25.00	20.00	22.85	2.854	27.48	21.98	25.11	3.170
Jun	31.78	25.42	29.05	3.161	29.25	23.40	26.73	2.898	32.15	25.72	29.38	3.200
Jul	43.46	34.77	39.72	3.202	40.00	32.00	36.56	2.936	43.96	35.17	40.18	3.226
Aug	52.15	41.72	47.66	3.234	48.00	38.40	43.87	2.972	52.75	42.20	48.22	3.252
Sep	47.26	37.81	43.20	3.237	43.50	34.80	39.76	2.967	47.81	38.25	43.70	3.252
Oct	37.48	29.99	34.26	3.227	34.50	27.60	31.53	2.991	37.92	30.33	34.65	3.265
Nov	39.11	31.29	35.75	3.372	36.00	28.80	32.90	3.176	39.56	31.65	36.16	3.439
Dec	39.11	31.29	35.75	3.545	36.00	28.80	32.90	3.381	39.56	31.65	36.16	3.601

	2004				2005				2006			
	Mid-C			NYMEX	Mid-C			NYMEX	Mid-C			NYMEX
Month	HLH	LLH	Flat	Gas	HLH	LLH	Flat	Gas	HLH	LLH	Flat	Gas
Jan	39.17	31.33	35.80	3.661	39.17	31.33	35.80	3.607	39.17	31.33	35.80	3.607
Feb	37.50	30.00	34.27	3.546	37.50	30.00	34.27	3.493	37.50	30.00	34.27	3.493
Mar	33.33	26.67	30.47	3.399	33.33	26.67	30.47	3.361	33.33	26.67	30.47	3.361
Apr	31.11	24.89	28.43	3.234	31.11	24.89	28.43	3.191	31.11	24.89	28.43	3.191
May	27.78	22.22	25.39	3.229	27.78	22.22	25.39	3.191	27.78	22.22	25.39	3.191
Jun	32.50	26.00	29.70	3.261	32.50	26.00	29.70	3.223	32.50	26.00	29.70	3.223
Jul	44.44	35.55	40.62	3.301	44.44	35.55	40.62	3.273	44.44	35.55	40.62	3.273
Aug	53.33	42.67	48.75	3.334	53.33	42.67	48.75	3.307	53.33	42.67	48.75	3.307
Sep	48.33	38.67	44.18	3.328	48.33	38.67	44.18	3.320	48.33	38.67	44.18	3.320
Oct	38.33	30.67	35.04	3.326	38.33	30.67	35.04	3.277	38.33	30.67	35.04	3.277
Nov	40.00	32.00	36.56	3.362	40.00	32.00	36.56	3.442	40.00	32.00	36.56	3.442
Dec	40.00	32.00	36.56	3.527	40.00	32.00	36.56	3.607	40.00	32.00	36.56	3.607

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!
!       Avista Corporation
!       System Study
!       CONFIDENTIAL AND PROPRIETARY-NOT FOR DISTRIBUTION
!       PROSYM Chronological Production Modeling System
!       50 MW YEAR-ROUND POTLATCH SCENARIO
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STATIONS SECTION

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Potlatch.Load
        StationGroup    Potlatch
        SpinStatus      0
        CapacityMax     -93
        Price           31.9
        Commit          1                                                   ! Approximates Sch. 25 w/o Surcharge
        Loadbiaser

Potlatch.PURPA
        StationGroup    Potlatch
        SpinStatus      1
        CapacityMax     50
        Commit          1
        Loadbiaser

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!
!       Avista Corporation
!       System Study
!       CONFIDENTIAL AND PROPRIETARY-NOT FOR DISTRIBUTION
!       PROSYM Chronological Production Modeling System
!       NO POTLATCH SCENARIO
!
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STATIONS SECTION

!XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX
!       Potlatch Contracts
!XXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXXX

Potlatch.Load
        StationGroup    Potlatch
        SpinStatus      0
        CapacityMax     -93
        Price           31.9                                            ! Approximates Sch. 25 w/o Surcharge
        Commit          1
        Loadbiaser

Potlatch.4Resale
        StationGroup    Potlatch
        SpinStatus      1
        CapacityMax     48.5
        Commit          1
        Loadbiaser

Potlatch.Resale
        StationGroup    Potlatch
        SpinStatus      1
        CapacityMax     -48.5
        Price           3.11                        ! Approximates Trans charges, including reserves and losses
        Commit          1
        Loadbiaser
```

Avista Corporation
1411 East Mission P.O. Box 3727
Spokane, Washington 99220-3727
Telephone 509-489-0500
Toll Free 800-727-9170

AVISTA Corp.

November 14, 2001

Jean D. Jewell, Secretary
Idaho Public Utilities Commission
472 West Washington Street
Boise, ID 83702

RE: Order No. 28884, Case No. AVU-E-01-12, Compliance Filing

Dear Ms. Jewell:

On April 27, 2001, Avista Utilities filed its 2001 Integrated Resource Plan (IRP) with the Idaho Public Utilities Commission (Commission). On October 24, 2001 the Commission issued its "Acceptance of Filing" with Order No. 28884.

On July 12, 2000 Avista prepared an update to its 1997 IRP to include known and significant changes. This updated IRP served as the basis for a Request-For-Proposals (RFP), which was issued on August 14, 2000. The updated 1997 IRP and the 2000 RFP included significant input from both the Idaho and Washington Commission Staffs. The 2001 IRP was a more formal report to support and report on the 2000 RFP activities. At that time, because no agreement had been reached with Potlatch, their total load was not included in either the updated 1997 IRP or the 2001 IRP after January 1, 2002, when their 10-year contract ended with Avista. Although the total load was not included, a small incremental load in excess of Potlatch's generation and interruptible purchases was included.

Avista also believes, along with the Commission staff, that the IRP process provides a valuable tool to both Avista and the Commission by providing additional communications between the company and other public entities.

Under Order No. 28884 the Commission required Avista to submit a revised load/resource balance schedules that would include the addition of known new generating resources and the load relating to Potlatch's Lewiston facility. Please find attached the load/resource tabulation dated November 5, 2001 to meet that requirement.

The differences between the annual load/resources tabulation, dated January 24, 2001, found in Appendix K of the 2001 IRP and the current load/resource tabulation dated November 5, 2001 are as follows:

1. System Load- the current load numbers reflect the new load forecast completed by the company in July 2001, which had a decrease in forecasted loads due to the current economic conditions in its service territory. Then Potlatch loads were added and were assumed to be 110 MW peak and 93 aMW annual energy.
2. PacifiCorp sale was increased 3aMW to reflect their option to increase the summer delivery term one additional month.
3. BPA- WNP #3 current numbers showed delivery and receipt of energy but the net effect of 10 aMW was the same.
4. Nichols Pumping showed a continuation of that load but only the amount to cover Avista's share of the pumping load at Colstrip.
5. Reserves were adjusted to reflect the changes in the forecasted peak loads.
6. Hydro numbers were adjusted to reflect the numbers in the most recent Northwest Power Pool regulation studies (2001-02). Canadian Entitlement Return numbers were changed to match the information from BPA. Contract Hydro numbers starting in 2005 were increased to reflect the proposed Priest Rapids and Wanapum contract extensions.
7. Small Power energy figure was increased 1 MW to reflect updated information.
8. Northeast and Rathdrum CT's peak capability was reduced to better match historical operating capabilities and the energy reflects the average of monthly generation required to meet load.
9. Kettle Falls CT and Boulder Park generation was added.
10. BPA Residential Exchange shows no peak or energy due to the fact that the company has decided to receive cash payments in lieu of power.
11. Kettle Falls energy was decreased 3 aMW to reflect actual operating characteristics.
12. Colstrip energy was decreased 1 aMW to reflect actual operating characteristics, and the energy in year 2002 was further reduced to account for increased maintenance outages for that year.
13. Coyote Springs II generation for 50% of the plant output was added.

Any questions on this compliance filing should be directed to:

Douglas Young
Contracts and Resource Administrator
Avista Utilities
P.O. Box 3727
Spokane, WA 99220
Phone: (509) 495-4521

Sincerely,

Lloyd Meyers

Lloyd Meyers
Vice President, Power Supply

AVISTA CORP.

Requirements and Resources
figures in MW (critical water)

Line No.	REQUIREMENTS	2002 Pk	2002 Avg	2003 Pk	2003 Avg	2004 Pk	2004 Avg	2005 Pk	2005 Avg	2006 Pk	2006 Avg	2007 Pk	2007 Avg	2008 Pk	2008 Avg	2009 Pk	2009 Avg	2010 Pk	2010 Avg	2011 Pk	2011 Avg
1	System Load	1584	986	1612	1006	1665	1040	1728	1079	1776	1109	1828	1142	1884	1177	1946	1215	2003	1251	2057	1285
2	PacifiCorp Exchange	0	3	0	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	Puget #2	33	25	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4	PacifiCorp 1994	0	12	0	12	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	PGE #1	150	0	150	0	150	0	150	0	150	0	150	0	150	0	150	0	150	0	150	0
6	BPA-WNP #3	0	32	0	32	0	32	0	32	0	32	0	32	0	32	0	32	0	32	0	32
7	Nichols Pumping	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
8	Reserves	248	0	251	0	256	0	263	0	268	0	273	0	278	0	285	0	290	0	296	0
9	TOTAL REQUIREMENTS	2016	1059	2014	1054	2072	1073	2142	1112	2195	1142	2252	1175	2313	1210	2382	1248	2444	1284	2504	1318
	RESOURCES																				
10	System Hydro	973	320	973	320	973	320	973	320	973	320	973	320	973	320	973	320	973	320	973	320
11	Contract Hydro	196	74	196	74	196	74	196	75	181	80	178	79	175	78	175	78	173	77	170	69
12	Can Ent Return	-8	-4	-8	-6	-11	-6	-12	-6	-8	-5	-8	-5	-8	-5	-8	-5	-8	-5	-8	-4
13	Small Power/Upriver	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
14	Northeast CTs	47	11	59	12	59	12	59	12	59	12	59	12	59	12	59	12	59	12	59	12
15	Kettle Falls CT	0	3	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
16	Boulder Park	25	19	25	20	25	21	25	21	25	21	25	21	25	21	25	23	25	23	25	23
17	Rathdrum CTs	164	112	164	69	164	109	164	116	164	125	164	128	164	116	164	130	164	132	164	135
18	SEMPRA	0	7	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
19	PacifiCorp Exchange	50	3	50	3	50	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0
20	Entitlement & Supplemental	4	0	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
21	BPA Res. Exchange	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
22	BPA-WNP #3	82	42	82	42	82	42	82	42	82	42	82	42	82	42	82	42	82	42	82	42
23	CSPE	9	5	8	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
24	TransAlta-Centralia	200	143	200	143	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
25	Thermal- Kettle Falls	49	42	49	42	49	42	49	42	49	42	49	42	49	42	49	42	49	42	49	42
26	Colstrip	222	186	222	190	222	190	222	190	222	190	222	190	222	190	222	190	222	190	222	190
27	CS II CCCT	0	64	136	117	136	117	136	115	136	117	136	117	136	115	136	117	136	117	136	115
28	TOTAL RESOURCES	2025	1039	2179	1046	1964	942	1913	946	1902	963	1899	965	1896	950	1896	968	1894	969	1891	963
29	SURPLUS (DEFICIT)	9	-20	165	-8	-108	-131	-229	-166	-293	-179	-353	-210	-417	-260	-486	-280	-550	-315	-613	-355

AVISTA UTILITIES
AVOIDED COST RATES FOR NON-FUELED PROJECTS
SMALLER THAN TEN MEGAWATTS
September 26, 2002

mills/kWh

LEVELIZED							NON-LEVELIZED	
CONTRACT LENGTH (YEARS)	ON-LINE YEAR						CONTRACT YEAR	NON-LEVELIZED RATES
	2002	2003	2004	2005	2006	2007		
1	39.36	40.34	41.35	42.39	43.45	44.54	2002	39.36
2	39.83	40.83	41.85	42.90	43.97	45.08	2003	40.34
3	40.30	41.30	42.34	43.40	44.49	45.60	2004	41.35
4	40.75	41.77	42.82	43.89	44.99	46.12	2005	42.39
5	41.21	42.24	43.30	44.38	45.49	46.63	2006	43.45
6	41.65	42.69	43.76	44.86	45.98	47.14	2007	44.54
7	42.09	43.14	44.22	45.33	46.47	47.63	2008	45.66
8	42.51	43.58	44.67	45.79	46.94	48.12	2009	46.80
9	42.93	44.01	45.11	46.24	47.40	48.59	2010	47.98
10	43.34	44.43	45.55	46.69	47.86	49.06	2011	49.18
11	43.75	44.84	45.97	47.12	48.30	49.51	2012	50.41
12	44.14	45.25	46.38	47.55	48.74	49.96	2013	51.68
13	44.53	45.64	46.79	47.96	49.16	50.40	2014	52.98
14	44.90	46.03	47.18	48.37	49.58	50.82	2015	54.31
15	45.27	46.41	47.57	48.76	49.99	51.24	2016	55.67
16	45.63	46.77	47.95	49.15	50.38	51.65	2017	57.07
17	45.98	47.13	48.31	49.52	50.77	52.04	2018	58.50
18	46.32	47.48	48.67	49.89	51.14	52.43	2019	59.97
19	46.65	47.82	49.02	50.25	51.51	52.80	2020	61.48
20	46.97	48.15	49.35	50.59	51.86	53.16	2021	63.02
							2022	64.60
							2023	66.23
							2024	67.89
							2025	69.60
							2026	71.35
							2027	73.14

AVISTA UTILITIES
AVOIDED COST RATES FOR FUELED PROJECTS
SMALLER THAN TEN MEGAWATTS
September 26, 2002

mills/kWh

LEVELIZED							NON-LEVELIZED	
CONTRACT LENGTH (YEARS)	ON-LINE YEAR						CONTRACT YEAR	NON-LEVELIZED RATES
	2002	2003	2004	2005	2006	2007		
1	12.73	13.03	13.33	13.63	13.95	14.27	2002	12.73
2	12.87	13.17	13.47	13.79	14.10	14.43	2003	13.02
3	13.01	13.31	13.62	13.93	14.26	14.58	2004	13.32
4	13.15	13.45	13.76	14.08	14.40	14.74	2005	13.63
5	13.28	13.59	13.90	14.22	14.55	14.89	2006	13.94
6	13.41	13.72	14.04	14.36	14.70	15.04	2007	14.27
7	13.54	13.86	14.18	14.50	14.84	15.18	2008	14.60
8	13.67	13.99	14.31	14.64	14.98	15.32	2009	14.93
9	13.79	14.11	14.44	14.77	15.11	15.46	2010	15.28
10	13.92	14.24	14.57	14.90	15.25	15.60	2011	15.63
11	14.03	14.36	14.69	15.03	15.38	15.73	2012	15.99
12	14.15	14.48	14.81	15.15	15.50	15.86	2013	16.36
13	14.26	14.59	14.93	15.27	15.63	15.99	2014	16.74
14	14.37	14.71	15.05	15.39	15.75	16.11	2015	17.13
15	14.48	14.82	15.16	15.51	15.87	16.23	2016	17.53
16	14.59	14.92	15.27	15.62	15.98	16.35	2017	17.93
17	14.69	15.03	15.38	15.73	16.09	16.47	2018	18.35
18	14.79	15.13	15.48	15.84	16.20	16.58	2019	18.77
19	14.88	15.23	15.58	15.94	16.31	16.69	2020	19.21
20	14.98	15.32	15.68	16.04	16.41	16.79	2021	19.65
							2022	20.11
							2023	20.58
							2024	21.06
							2025	21.55
							2026	22.05
							2027	22.56

EFFECTIVE DATE	ADJUSTABLE COMPONENT
9/26/2002	26.63

The total avoided cost rate in each year is the sum of the adjustable component and the fixed component from either of the tables above.

Example 1. A 20-year levelized contract with a 2002 on-line date would receive the following rates:

Years	Rate
1	14.98 + 26.63
2-20	14.98 + Adjustable component in each year

Example 2. A 4-year non-levelized contract with a 2002 on-line date would receive the following rates:

Years	Rate
1	12.73 + 26.63
2	13.02 + Adjustable component in year 2003
3	13.32 + Adjustable component in year 2004
4	13.63 + Adjustable component in year 2005