BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE INVESTIGATION)	
OF THE CONTINUED REASONABLENESS OF)	
CURRENT SIZE LIMITATIONS FOR PURPA)	CASE NO. GNR-E-02-1
QF PUBLISHED RATE ELIGIBILITY	)
(i.e., 1 MW) AND RESTRICTIONS ON)	
CONTRACT LENGTH (i.e., 5 YEARS)	)
)	

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

DENNIS E. PESEAU

Q. Please state your name and business address for the record.

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 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. Does Exhibit 103 accurately describe your background and experience?

A. Yes, although my testimony below expands this information to be more specific as to my participation in Idaho in regard to avoided costs.

Q. What is the subject of your direct testimony?

A. On July 2, 2002 the Idaho Public Utilities Commission ("the Commission") issued Order No. 29069, an order on various petitions for reconsideration and motions to stay related to its May 21, 2002 Order No. 29029. Among other things, Order No. 29069 set testimony and hearing

dates for these proceedings. The Commission indicated that " . . . [T]he purpose of the hearing is to receive evidence on the reasonableness of the variables in the existing avoided cost rate methodology . . ." [Order No. 29069, Page 8.] My testimony will demonstrate that some of the existing variables are no longer reasonable and propose revised variables that will more accurately track future generation costs.

Q. Have you computed avoided costs and rates in Idaho previously?

A. Yes. I and others in my firm participated in the original PURPA proceedings in Idaho in the early 1980s on behalf of the Independent Power Producers of Idaho. We continued to develop avoided cost methodology and policy issues in Idaho until 1997. Our firm has been similarly involved in PURPA avoided cost matters in numerous state jurisdictions and in filings before the FERC.

Q. Do you propose changes in the existing avoided cost methodology in your testimony?

A. No. As I understand the Commission's intentions, the purpose of these proceedings is to minimize the time period in which present published rates are stayed

by addressing only issues that involve an updating of the variables and data necessary to compute avoided costs within the existing methodology. The avoided costs I offer herein continue to be based on the Surrogate Avoided Resource (SAR) as used by this Commission for some time. I will, however, propose enhancements within the SAR method.

Q. What conclusions have you reached from your review of the filings in this case?

A. I conclude that there are understandable tensions in Idaho at this time between the interests of ratepayers and the interests of potential qualifying facilities (QF) developers.

The present proceedings are all about costs and rates. The old assumptions regarding the physical and financial variables inherent in determining avoided cost rates have suddenly become very prominent due to the very high rates produced by the lengthening of available contract terms from five to twenty years. These high rates are shown in Order No. 29057 in Case Nos. AVU-E-02-4, IPC-E-02-6, and UPL-E-02-1. Rates this high will undoubtedly attract the attention of the major national and international developer interests. But any avoided cost rates that exceed present utilities' incremental costs by

significant amounts would not be in the long-term interests of local QF developers and certainly not ratepayers. However, with the vanishing resource surplus in the West, properly computed avoided cost rates in Idaho and elsewhere should provide for healthy economic climate for QF development.

Potential developers naturally view the prospect of very high published rates computed using the past assumptions favorably. Utilities and Staff have raised concerns that these past assumptions will stimulate excess development and much higher rates to ratepayers than if lower cost alternative power sources are acquired.

The Commission has acted quickly and responsibly to reconsider the many complex assumptions and variables making up avoided cost estimates in a manner that should not delay developers the timely opportunity to enter into contracts.

Q. Do you have a recommendation that might simplify and expedite a resetting of avoided cost rates for these proceedings?

A. Yes. At the risk of slightly oversimplifying, I contend that the reason that the current published rates are too high can be attributed almost

exclusively to two factors: one, a grossly inaccurate estimate of initial natural gas prices and, two, a grossly excessive estimate of natural gas escalation used in computing the levelized fuel component available for "non-fueled projects."

I conclude that specific attention and modification of these two factors would provide a reasonable basis for rates for developers wishing to immediately pursue contracts. I recommend that the Commission adjust these two fuel-related variables and set new rates. At that point I would recommend that the Commission expeditiously convene a proceeding during which the Commission could rigorously consider the additional issues that the Commission should evaluate to set accurate avoided cost rates in the new world of open transmission access and deregulated wholesale markets. As some parties have noted, consideration of QF dispatchability, seasonal and daily production characteristics, extent of capacity value and more accurate and flexible quantification of the impact QF resource additions will have on avoided costs is necessary to set a lasting and stable QF environment.

These additional enhancements can be considered expeditiously, but not in the accelerated

schedule set for these proceedings. Below I address the two key fuel-related factors and the remaining list of previous “typical” avoided cost determinants and the rates which result from my recommendations.

Q. Why are frequent updates to avoided cost variables necessary?

A. Accurate estimates of avoided costs have always been necessary to assure that a proper balance between ratepayers’ interests and qualifying facilities (QFs) is maintained. Avoided cost-based rates that are too high are costly to ratepayers, while avoided cost-based rates that are too low discourage the development of cost effective levels of QF projects.

One original intent of PURPA was to encourage some competition between generating resources of regulated electric utilities and outside generating resources. However, with open access and deregulation of wholesale power markets competition among generators to sell to utilities is significantly increased.

Perhaps most importantly, frequent updates of avoided costs are necessary because the utility’s marginal or incremental costs upon which avoided costs are based may change frequently, especially in today’s utility

environment.

Q. What are the principal variables affecting a utility's incremental and avoided costs?

A. Under the SAR methodology, the capital and operating costs of the SAR plant, the assumed rates at which capital and operating costs escalate, the forecast date in which the new SAR plant is needed and, finally, the short-term cost or value of short-term surplus energy in years prior to the load/resource deficit are the key factors or variables making up incremental or avoided costs.

A more specific list of these key variables was provided by Staff in its May 22, 2002 draft update of avoided costs. I include this list as page 1 of my Exhibit 104 for purposes of discussing the updates that I recommend, along with the updated values I testify to below.

Q. When were the values of the variables listed in your Exhibit 104 originally set by this commission?

A. With the exception of "current year fuel cost" these values were set prior to 1997. The current year fuel forecast is updated annually, but is tied to average gas prices at Sumas, Washington that are two years

old. All of the variables used in establishing the SAR avoided costs are clearly in need of review.

Q. How will your review of necessary variable updates proceed?

A. I will follow generally the list of variables in my Exhibit 104. However, I will attempt to address each variable in descending order of importance in the calculation of avoided costs. Far and away the most important variables in determining today's avoided costs are today's actual natural gas prices delivered to the SAR combined cycle combustion turbine (CCCT) and, for the non-fueled levelized rate option, the escalation rate assumed today for the delivered natural gas price over the life of the QF contract.

NATURAL GAS PRICES

Q. Why is the "current year fuel cost" such a large and important variable in determining avoided costs?

A. The SAR is presumed to be a Combined Cycle Combustion Turbine (CCCT). This technology is relatively capital efficient in that these plants are capable of being operated at very high capacity factors and have relatively low capital costs. Fuel and associated variable costs, here natural gas, will typically comprise more than two-

thirds of total power costs making up avoided costs. Therefore, the SAR natural gas cost adopted for purposes of estimating avoided costs must be indicative of what the utility would pay in the particular year the CCCT is assumed to be brought on line.

Q. What is the price of natural gas delivered to the CCCT assumed to be in the proposed 2002-2003 avoided cost update?

A. As pointed out by staff in its June 25, 2002 Supplemental Answer,

> . . . At the present time, the starting fuel price subject to 6% escalation over the life of contracts signed or requested this year is $4.82 per MMBtu. This price will increase to $5.23 in July if approved by the Commission. Under any other gas price methodology such as historical averages, historical trend lines or future market projections, the resulting avoided costs would be significantly below that using the existing methodology . . .
>
> [Staff Supplemental Answer, Page 3.]

Failure to update the gas price assumption to reflect actual natural gas prices today will result in the use of a $5.23 per MMBtu gas price as the basis for

computing the adjustable avoided cost rate for fueled rates, contracts and as the initial rate to be escalated for non-fueled rate contracts.

Q. Is the $5.23 per MMBtu natural gas price a reasonable assumption today?

A. No. For example, at the time of the writing of this testimony, the Sumas, Washington natural gas price, adjusted for delivery into Idaho on Northwest Pipeline is approximately $1.86 MMBtu ($1.51 border price, plus $.35). Use of the $5.23 figure for purposes of setting avoided costs for both fueled and non-fueled contracts would be very detrimental to ratepayers and is not in the public interest.

Q. What adjustments to the assumed natural gas price are necessary in order to reflect current and likely annual 2002-2003 prices?

A. The base price of natural gas delivered to Idaho should be reset to $2.79 per MMBtu for purposes of estimating avoided cost rates.

Q. How did you determine a natural gas price of $2.79 per MMBtu?

A. I began with a review of the daily firm prices of natural gas transactions at Sumas, Washington.

Sumas is the trading center that has been used recently for indexing natural gas prices for avoided costs in Idaho. Attached as my Exhibit 105 is a copy of daily recorded transactions at Sumas for the year ending July 17, 2002. Although average prices at Sumas during this period were as low as $1.08 per MMBtu and as high as $3.43 per MMBtu, the vast majority of gas sales were at prices that ranged between $1.80-2.70 per MMBtu. I note that, consistent with other forecasts, the trend in gas prices was downward from July 2001-July 2002.

Q. What is the average cost of delivering gas from Sumas to Idaho?

A. The firm transportation rates for delivery from either Sumas or the Rockies on Northwest Pipeline are approximately $.35 per MMBtu.

Q. What information and forecasts did you review in your concluding on the $2.79 per MMBtu?

A. In addition to the most recent gas prices at Sumas, Washington I analyzed the April 25, 2002 Draft Fuel Price Forecasts for the 5th Northwest Conservation and Electric Power Plan published by the Northwest Power Planning Council. Although this document, which I attach as my Exhibit 106, is a draft, it is very similar to the

Council's methods and forecasts used in its 4th Plan. In addition, most of the natural gas commodity price, transportation, well-head price and regional basis differential data are simply taken from established and reputable forecasting and data processing organizations.

A review of the Council's 5th Plan supported my recommended gas price of $2.79 per MMBtu.

Q. How do other forecasting organizations' natural gas price forecasts compare with your recommended $2.79 per MMBtu?

A. I reviewed the 2002-2003 U.S. wellhead natural gas price forecast for the U.S. Energy Information Administration, the Gas Research Institute, the draft California Energy Commission and the DRI-WEFA forecast. These institutions forecast national wellhead gas prices in the range of $2.60-$2.90 per MMBtu. National wellhead prices have a basis differential that is higher than Sumas by $.35-.45 per MMBtu. That is, these national wellhead prices must be reduced by $.35-.45 per MMBtu to be made into a comparable Sumas, Washington gas price forecast. These forecasts are summarized in the Council's 5th Plan.

Q. Exactly how did you reach a recommended price of $2.79 per MMBtu delivered to Idaho?

A. In order to reduce these ranges of prices to a single price, I averaged the 2002 and 2003 gas price forecasts for Pacific Northwest natural gas prices for regional utilities. The 2002 gas price of $2.53 and the 2003 gas price of $3.04 per MMBtu can be found on Page F-1, Appendix C of my Exhibit 106. The simple average of these prices is $2.79, which I recommend be used as the base gas price for purposes of setting avoided cost rates in these proceedings.

Q. Aren't "forward price" curves available from which the 2002-2003 Idaho natural gas prices could be predicted?

A. Yes. However, these forward price quotes are somewhat volatile. For example, I received a forward price on Platt's Gas Daily today (July 18, 2002) for July 2002-July 2003 for $1.90 flat from Sumas and $1.26 flat from the Rockies, both deliverable to Idaho for an additional $.35 per MMBtu. Given potential volatility, I continue to recommend the price of $2.79 per MMBtu.

Q. What is the significance of the second natural gas price factor you alluded to above, the escalation rate to be used for multi-year non-fueled projects?

A. Both fueled and non-fueled projects are entitled to rates containing a levelized capacity cost component. Non-fueled projects are entitled to a rate which also contains a levelized fuel component. Since the effect of levelizing the fuel component is to lock in an assumed rate of inflation and “front-end” load this assumed inflation over the life of the contract, it is very important to use a realistic rate. Staff’s Supplemental Answer, Pages 2-3 discusses the significant impact that the fuel price escalator has upon non-fueled levelized rates.

Q. What fuel price escalator has been used recently for purposes of computing non-fueled project rates?

A. 6%.

Q. Is a 6% assumed escalation rate for natural gas a reliable escalator for today’s or near-term future gas prices?

A. No. In fact retail gas prices in the Pacific Northwest have generally been flat since the late 1980s, rising only moderately. The one notable exception to this relative price stability was, as we are all painfully aware, the huge natural gas (and electric) price runup from fall 2000 to spring 2001. Any simple trending

or averaging technique used to attempt to forecast price escalation will be unduly influenced by this market aberration. The actual cause of this unpredicted price runup remains the subject of numerous lawsuits and regulatory inquiries in the western U.S.

Q. Do you have a specific natural gas price escalation rate that you recommend be used in these proceedings for purposes of the levelized fuel component for non-fueled contract rates?

A. Yes. For the most part, natural gas forecasts show little or no “real” escalation. That is, gas prices are predicted to escalate at near the general rate of inflation. For example, the Northwest Power Planning Council report referenced above shows forecasts of escalation rates of about .5% in real terms.

Upon review of Idaho Power’s 2002 IRP, I noted that the WEFA Group’s long-term gas escalator is 2.62% nominal. For purposes of estimating avoided cost rates for non-fueled contracts this year, I recommend that the escalation variable be changed from the previous 6% to 2.62%. For each subsequent update, I strongly recommend an updating of this variable.

Q. You indicated previously that the two

variables you have just discussed, the initial base natural gas price and the rate at which it escalates for non-fueled contracts, are most crucial for this abbreviated proceeding. Are you prepared to discuss other variable updates?

A. Yes. Again I believe the two variables above to be most important for purposes of setting an immediate or interim rate. For determining an update on certain of the engineering, operating and cost data, Idaho Power has retained the firm of Parsons Brinckerhoff. This firm has provided me with the following SAR variables:

SAR Plant Life

SAR Plant Cost

SAR Capacity Factor

SAR Fixed O&M

SAR Variable O&M

The values for these variables and the base natural gas cost and escalation rate I just recommended are summarized in my Exhibit 104, along with the variable values I now discuss.

FIRST YEAR DEFICIT

Q. Why is the first year of generating resource deficit an important variable for computing avoided costs?

A. Under the SAR methodology, the avoided cost rate is computed as a surplus energy value for the immediate years in which the utility is surplus and a full capacity and energy value for the SAR from the first year of resource deficit forward. As the capacity and energy value of the SAR together is generally greater than the value of surplus energy, different assumptions on the year of the deficit will alter the levelized avoided cost. I note, however, that under the assumptions for surplus energy values used in this case, the deficit year issue is not very significant.

Q. What is the period you recommend as that Idaho power shows the need for new permanent resources?

A. The year 2005. Idaho Power's IRP indicates that the Company will require additional permanent resources beginning in June 2005 (IRP Page 4). There are limited peak deficits prior to 2005. Under poorer than median water conditions and greater than expected loads, small monthly energy deficits between in 2004. Accelerating the first deficit year by one year makes only

a one mill difference in a twenty year non-fueled contract.

SURPLUS ENERGY COSTS

Q. What surplus energy cost do you use to compute avoided costs?

A. I use a 2002 base year surplus energy cost of 28.28 mills/kWh, escalated at 5.90% annually.

CURRENT YEAR FUEL COST

Q. What value do you use to measure the current year fuel cost?

A. The current year fuel cost is determined by multiplying my $2.79 per MMBtu, 2002-2003 natural gas fuel cost by the SAR heat rate of 6994 Btu/kWh. This results in a current year fuel cost of 19.51 mills/kWh.

UNCHANGED VARIABLES

Q. Have some of the variables used in the computing of avoided costs remained unchanged?

A. Yes. Some of the variables, such as the utility's weighted cost of capital, ratepayer discount rate and capital carrying charge rate, remain the same as by prior Commission approval.

The remaining unchanged variable, the SAR plant life, is still thirty years as the CCCT technology is essentially unchanged.

SEASONALIZATION OF AVOIDED COSTS

Q. What is the issue with respect to the seasonalization of avoided costs?

A. The calculation of avoided costs is based on the utility's incremental or marginal costs. As is true for many utilities, and is particularly true for Idaho Power, incremental capacity and energy costs vary by season. To the extent that avoided costs rates are also seasonalized, QF projects that produce power during months in which Idaho Power experiences high loads and/or high costs will receive higher published rates. This is a very positive cost-based incentive for QFs and a means to minimize ratepayers' revenue requirement.

This is recognized currently in Staff's avoided cost methodology program, although the seasonalization factors are currently set to zero. In an effort to reward appropriate QF technologies, particularly QFs that should be able to some extent shape their production such as anaerobic digesters, the existing seasonalization factors approved by the Commission in Idaho Power's last incremental cost study should continue to be reflected in published avoided cost rates.

Q. Is the use of seasonalized published rates

in accord with sections 201 and 210 of PURPA?

A. Yes. The essential concept expressed by the FERC was that of calculating avoided cost-based rates in accordance with the incremental cost of the utility “but for” the purchase from the QF. Prior rate cases, and rates to ratepayers approved by the Commission clearly establish that Idaho Power’s incremental costs vary by season. Furthermore, in my opinion, seasonalized avoided cost rates better conform to rates that are just and reasonable to Idaho Power’s ratepayers, and would eliminate any discrimination against QFs because rates paid to them would be in stricter accordance with incremental costs.

Q. Were prior published QF rates seasonalized?

A. Yes, my understanding is that seasonalized rates have been approved by the Commission for Idaho Power.

Q. What are the presently approved seasonalization factors of Idaho Power?

A. The factors are as follows: .735 for March through May, 1.2 for June through September, and 1.0 October through February, as established in Commission Order No. 20350. These, or updated seasonal factors, should continue to be used to avoid cost payments.

Q. Do you have concluding remarks?

A. Yes. As we enter a period of need for additional resources, certain other aspects of QF contracts may need to be considered. Topics I mentioned at the outset of my testimony include dispatchability, a review of seasonal factors, contribution to capacity at peak, and load/resource balances. The intent of considering these factors would be to add certainty and value for the QF projects most capable of contributing to the operating needs of Idaho Power. A quick resolution of the base fuel rate and fuel escalator issues with the setting of rates based on updating these two key variables would provide additional breathing room in which to consider these other important considerations.

Q. Does this conclude your direct testimony?

A. Yes, it does.