Office of the Secretary
Service Date
September 26, 2002

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE INVESTIGATION OF THE CONTINUED REASONABLENESS OF CURRENT SIZE LIMITATIONS FOR PURPA QF PUBLISHED RATE ELIGIBILITY (i.e., 1 MW) AND RESTRICTIONS ON CONTRACT LENGTH (i.e., 5 YEARS).	**CASE NO. GNR-E-02-1** **ORDER NO. 29124**

Sections 201 and 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA) and pertinent regulations of the Federal Energy Regulatory Commission (FERC) require regulated electric utilities to purchase power from qualifying facilities (QFs). On February 5, 2002, the Commission initiated this generic docket soliciting comments on the reasonableness of existing project size limitations for QFs of 1 MW and the five-year restriction on QF contract length. On May 21, 2002, the Commission issued Order No. 29029 increasing the size of QFs eligible for published rates from 1 MW to 5 MW and increasing the maximum required contract length from 5 years to 20 years.

On May 21, 2002, Idaho Power Company filed a Motion to Stay Entitlement to Published Rates, and Avista Utilities filed a similar motion on June 11, 2002. On June 10, 2002, Petitions for Reconsideration were filed by J. R. Simplot Company (Simplot) and Earth Power Resources, Inc. (Earth Power). Petitions for Reconsideration were also filed by Idaho Power and Avista on June 11, 2002.

The Commission in Order No. 29069 issued July 2, 2002 (1) granted the Petition for Reconsideration filed by Simplot and Earth Power and increased the size of QFs eligible for published rates from 5 MW to 10 MW; (2) granted the Petitions for Reconsideration filed by Idaho Power and Avista for the purpose of reviewing the reasonableness of the variables in the existing avoided cost methodology and scheduled an August hearing on the reconsideration; and (3) granted the Motions for Stay filed by Idaho Power and Avista staying the published rates resulting from Order No. 29029, except as they apply to existing QF contracts, until the Commission rendered this decision on reconsideration.

The Commission in this Order approves changes to the generic variables in the avoided cost methodology, approves the resultant fueled and non-fueled avoided cost rates for Idaho Power Company, Avista Corporation, and PacifiCorp and reaffirms the changes to contract length for QFs smaller than 10 MW approved in Order No. 29069.

ORDER NO. 29029

The Commission initiated this case to review by written comments whether the current size limitations for QFs eligible for published rates and restrictions on contract length were still reasonable. Comments were received from developers of QF facilities, from interested persons and from the regulated electric utility companies (Idaho Power, Avista, and PacifiCorp) required to purchase QF power. Prior to the issuance of Order No. 29029, QFs were eligible to contract to sell energy at the published rates if the facility produced up to 1 MW of electricity, and the purchasing utilities were required to provide a contract length of at least five years.

Regarding the standard contract length, the Commission noted in Order No. 29029 that its policy has changed during the years that PURPA has been effective in Idaho. For the first seven years, through 1987, utilities were obligated to provide QFs with a 35-year contract. In 1987, the Commission shortened the standard contract length to 20 years to reduce the risk and uncertainty inherent in long range forecasting. The Commission in 1996 shortened the standard contract length to five years for projects 1 MW and larger.

Regarding the production capacity of QFs eligible to receive published rates, FERC rules and regulations require only that QFs with a design capacity of 100 kW or less be eligible. *See* 18 C.F.R. § 292.304(c). PURPA does not prohibit larger projects from being eligible for published rates and this Commission had set the design capacity limit at 1 MW.

After reviewing the comments filed by all the parties, the Commission in Order No. 29029 found "that a convincing case has been made to increase the QF size threshold for published rate eligibility to 5 MW and also to provide QFs with contracts of up to 20 years in length." Order No. 29029, p. 9. Despite a recommendation made by many parties in the case to expand the proceedings to explore avoided costs methodology and other QF issues, the Commission declined to expand the scope of the case beyond the issues identified, i.e., restrictions on contract length and QF published rate eligibility.

PETITIONS FOR RECONSIDERATION

The sole issue raised by the Petitions for Reconsideration filed by Simplot and Earth Resources is the Commission's decision on the size of QFs eligible for published rates. Simplot and Earth Power asked the Commission to grant reconsideration to increase the eligible QF size from 5 MW to 10 MW. The companies point out that QFs in size between 5 and 10 MW provide 56% of the total megawatt capacity provided to Idaho Power by QFs. Simplot contends the 5

MW limitation will prevent many QFs, such as wind, geothermal and biomass, from capturing economies of scale. Simplot and Earth Power also contend the effect of a 10 MW versus a 5 MW QF on a utility's electrical system is inconsequential. The companies assert that if the published avoided rates are no longer fair and accurate, the appropriate response is to adjust the rates, rather than limit too narrowly the size of QFs eligible for published rates.

The Petitions for Reconsideration of Idaho Power and Avista address the reasonableness of the existing rates, especially in light of the Commission's decision to extend the contract period to 20 years. Idaho Power contends the Commission's Order is "unreasonable, unlawful, erroneous, unduly discriminatory, not based on facts in the record, and is inconsistent with applicable law because the rates established by the Order for payment to qualifying cogenerators and small power producers (QFs) exceed the level permitted by federal law." The Company contends federal law requires that purchase rates set by the Commission cannot result in the utility paying QFs more than the utility's avoided costs. Idaho Power asserts that the Commission, by focusing only on QF eligibility size and the mandatory contract length, failed to recognize the real effect of the Commission's decision on those issues. According to Idaho Power, "by changing the mandatory term of the contract from 5 years to 20 years, the Commission increased the levelized published rates Idaho Power will have to offer to QFs that are entitled to receive the published rates. The resulting levelized purchase prices substantially exceed Idaho Power's current avoided costs." Idaho Power asked the Commission to stay the effectiveness of Order No. 29029 to allow time to update the assumptions in the existing avoided cost rate methodology.

Avista made an argument similar to Idaho Power's in its Petition for Reconsideration. Avista claims the current published cost rates are not a fair, reasonable and accurate representation of the costs of the surrogate avoided resource (SAR) over a 20-year period. The Company contends the published rates over a 20-year period are much higher than Avista's current estimates of the costs associated with constructing a combined cycle combustion turbine. Avista requested that the Commission grant rehearing for the purpose of receiving evidence and current information on avoided costs before QFs are entitled to 20-year contracts.

RECONSIDERATION – TECHNICAL HEARING

The Commission initiated this case to review only the reasonableness of existing limitations on QF contract length and the size limitation on QFs eligible to sell energy at published rates. As the petitions and motions of Idaho Power and Avista make clear, however, changing those factors can have a significant effect on the overall reasonableness of the QF terms during the life of the contract. In this case, the Commission has approved increases in the maximum QF project size, from 1 MW to 10 MW, and in the contract length, from five years to 20 years. If the variables that make up the avoided cost formula are inaccurate, the effect will be magnified significantly because the resulting rates will be in place over a 20-year contract. As Simplot and Earth Power suggest, the cure is not to shorten the contract length or to decrease the maximum project size, but to review and adjust if necessary the variables in the avoided cost formula.

The other major factor affecting published rates is the recent extreme volatility in gas prices. The published rates are adjusted each year based on the average gas price at Sumas, Washington. The past two years saw extremely high spikes in natural gas prices, resulting in higher published rates. Gas prices have now returned to more normal levels. QF contracts signed now calculated with abnormally high gas rates that are then escalated at the currently accepted rate of 6% each year under the avoided cost rate formula could result in unreasonable and unfair costs borne by the regulated utility, which ultimately will be paid by its ratepayers. The Commission cannot expose ratepayers to avoided cost rates that rely too heavily on uncharacteristically high gas prices in combination with a high escalation rate.

On August 12, 13, 2002, the Commission on reconsideration held a technical hearing in Boise, Idaho on the continued reasonableness of the variables in existing avoided cost rate methodology. The following parties appeared by and through their counsel of record:

Idaho Power Company	Barton L. Kline; Monica Moen
Avista Corporation	R. Blair Strong
PacifiCorp	John M. Eriksson
Independent Energy Producers of Idaho & J.R. Simplot Company	Peter J. Richardson
Potlatch Corporation & Wind Works, Inc.	Conley Ward
Plummer Forest Products, Inc.	Dean J. Miller
Commission Staff	Scott Woodbury

The Commission has reviewed and considered the transcripts of the proceedings in this case including exhibits, our underlying related Orders and filed comments. Not all parties addressed all the variables. Some variables were deemed to be more critical than others, i.e., current year fuel cost, fuel escalation rate and first deficit year. The following matrix depicts the changes in variables proposed by the parties:

COMPARISON OF PROPOSED VARIABLES

Data Type	Current Variables	Staff	Avista	Idaho Power	PacifiCorp	IEPI	Plummer/ Potlatch	Avista Rebuttal	PacifiCorp Rebuttal	IEPI Rebuttal
Surplus Energy Cost (mil/kWh):	19.00	Abandon	22.12 to 30.73	28.28	33.54	Abandon		22.12 to 30.73	33.54	Abandon
Surplus Cost Base Year:	1994	Abandon	2002	2002	2002	Abandon		2002	2002	Abandon
First Deficit Year:	2010/ 1998/1999	Abandon	2007	2005	2008	Abandon	2000/ NA/NA	2007	2008	Abandon
"SAR" Plant Life (Years):	30	No Change	No Change	No Change	No Change			No Change	No Change	
"SAR" Plant Cost ($/kW):	$667	$679	$577	$686/ $729	$632			$669	$632	
Base Year of "SAR" Cost:	1994	2000	2000	2002	2002			2002	2000	
"SAR" Capacity Factor (%):	92%	No Change	89.5%		No Change			91.38	No Change	
"SAR" Fixed O&M ($/kW):	$7.43	$10.70	$14.75	$9.45	$7.00			$9.04	$8.10	
"SAR" Variable O&M (mil/kWh):	1.65	2.80	2.80	3.27	1.61			2.69	2.80	
Current Yr Fuel Cost ($/MMBtu):	$5.23	$3.19	NWPPC	$2.79	$3.95	$3.84		NWPPC	$3.19	$3.91
Base Year, O&M Expenses:	1994	2000	2000	2002	2002			2002	2000	
Escalation Rate; "SAR" (%):	3.60%	2.10%	2.40%		0.47% thru 2007 2.5% after			2.26%	2.10%	
Escalation Rate; Surplus (%):	4.50%	Abandon	see above	5.90%	4.80			see above	4.80%	
Escalation Rate; O&M (%):	3.21%	2.70%	2.40%		2.50%			2.53%	2.70%	
Escalation Rate; Fuel (%):	6.0% nom	4.4% nom	NWPPC	2.62% nom	1.97%	3.10%		3.27% NWPPC	3.10% NWPPC	3.60%
"Tilting" Rate (%):	3.60%	2.10%	2.40%		2.50%			2.38%	2.10%	
Heat Rate (Btu/kWh):	7350	7100	7340	6899/ 6994	7074			7127	7100	

Avista, on rebuttal, recommends averaging the recommendations made for capital cost, O&M cost, heat rate, and escalation rates. Avista also accepts Staff's proposal to use a five-year rolling average to establish the starting year gas price, but proposes using a 50/50 blend of Sumas and AECO gas prices. IEPI, on rebuttal, recommends that 3% be added to each utility's capital carrying charge.

The positions advanced by the parties and our findings as to the continued reasonableness of the variables can be summarized as follows:

First Deficit Year

The first deficit year determines the point at which the avoided cost rate converts from a surplus energy cost to a rate that includes both the energy and capacity costs of the surrogate avoided resource (SAR). The first deficit year for each utility is based on the utility's load/resource balance and forecast.

The Commission Staff proposed to abandon the "first deficit year" as an avoided cost variable, together with the related surplus energy cost and surplus escalation rate. In support of its position, Staff recited the following nine reasons:

1. Establishment of utilities' first deficit years requires regular filings by the utilities followed by Commission Orders. None of the utilities have made a filing to update its first deficit year since the first deficit years were last established in 1996.

2. It is unclear whether determination of a first deficit year should be based on a utility's energy needs or capacity needs.

3. When a utility becomes deficit depends on the conditions assumed for planning. Water conditions and reserve margins used for planning are not consistent for all of the utilities.

4. Load forecasts are one half of the surplus/deficit equation. Load forecasts are prepared entirely by each utility with little or no oversight. Utilities can easily manipulate their load forecasts to produce a desired result.

5. Utilities increasingly rely on market purchases. Should long-term contracts that do not begin for several years be counted as resources in determining first deficit year?

6. The difference between "surplus" energy rates and "SAR-based" rates is not as great as it used to be; therefore, there is less justification for two different bases for parts of the avoided cost computations.

7. Utilities always plan to be surplus in the short-term, at least for as long as it takes to acquire new resources. Having too large of surplus can be as

problematic as being deficit. Avoided cost rates should not provide incentives for a utility to increase its surplus period.

8. The addition of a PURPA project, particularly if it is less than 10 MW, does not have a large impact on a utility's load-resource balance. The cumulative effect of many PURPA projects could have a significant impact, but the capacity of PURPA projects has historically been small.

9. If surplus energy rates are retained in the avoided cost analysis, determination of the prices to be used during a utility's surplus period poses some difficulty because of recent extreme variations in market prices.

Staff and IEPI's proposal to eliminate the "first deficit year" as an avoided cost variable was met with considerable opposition from Avista and PacifiCorp. No party, however, disputed any of the reasons advanced by Staff. Establishing the first deficit year was likened by Staff to a mirage in the desert, a goal which can never be reached. It was also suggested by Plummer that it poses a "Catch 22" dilemma – i.e., a utility only has to purchase if it's deficit; however, a utility can extend its surplus by constructing its own resources, so a utility is never deficit and never has to purchase.

The testimony at hearing reflected the difficulty in determining a first deficit year. The inherent problem lies in the fact that a utility's loads and resources are by their very nature dynamic and continuously changing. 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 SAR-based capacity and energy value from the first year of resource deficit forward. If the surplus period is not recognized, the utility will immediately pay an avoided cost based on the SAR. Such a result, the utilities argue, may run counter to the requirements of PURPA and FERC which require consideration of a utility's "need" for resources and its marginal or incremental costs. Reference 18 C.F.R. § 292.304 Rates for Purchases. Issues concerning the deficit year computation, utilities suggest, can be adequately addressed with some additional effort on the utility's part. It is Staff's contention that it would be an inordinate amount of effort for what amounted to only about a 3 mill change in the avoided cost. Considering that two-thirds or more of the avoided cost rate with a natural gas CCCT for SAR is entirely dependent on fuel, Staff notes that there is a huge amount of uncertainty in the setting of any avoided cost rate. The parties should be mindful, Staff notes, that avoided cost calculation is not an exact science;

it is only an approximation. Testimony revealed considerable concern that the utility companies could continue to game the system. One need only to look at Avista for an example of the problems inherent in the first deficit year. Avista in its last IRP (2001) recognized the need to update its avoided costs, promised to do so and then failed to do so. Avista is a utility officially on record as implicitly claiming to have adequate resources through 2007-2010 and yet it is nevertheless building and buying resources, in addition to covering deficits with purchased power. Avista is not alone, however – all the utilities in this case are adding additional generating capacity, gas combustion turbines that are smaller in size and more rapidly installed. As a consequence, company IRPs almost never accurately reflect a utility's actual surplus/deficit situation.

As the utilities candidly admit, their load/resource balances are not static numbers but can change from day to day. Indeed, in the short course of these proceedings Avista in its filings has claimed a number of different first deficit years. The record reflects the year that it presently recommends, 2007, may be in error because the Company continues to factor in Potlatch's self-generation as if it were a contracted resource and it is not. As recognized by the parties, all utilities in this proceeding are reconsidering their energy purchase strategies and have been recently active in upgrading existing resources and/or building or contracting for new resources and capacity. As a new twist, supply resources are often also being developed through the unregulated subsidiaries of utilities, thus avoiding or delaying regulatory scrutiny. Not once during this recent period of resource acquisition and building, it was noted, did a utility suggest that we should revisit avoided cost rates because perhaps the rates were too low, failed to reflect the need for resources and were not sending an appropriate market signal to QFs. In failing to do so, it was suggested that utilities have denied their customers a least-cost opportunity to acquire a greater diversity in supply resources.

The continued importance of a first deficit year in avoided cost calculations has to be weighed against the improbability of settling on a surplus period in which anyone has confidence. Utilities have had the opportunity to instill confidence in the first deficit year but in failing to update for changes in load/resource balance have compromised the public confidence in the reasonableness of its continued use. It is a factor in avoided cost calculation, the Commission finds, that needs to be taken into account only to the extent practicable. Reference 18 C.F.R. § 292.304(e). The record supports a finding that continued use of the first deficit year is administratively burdensome and no longer practicable. We therefore accept Staff and IEPI's proposals to abandon the first deficit year. In doing so, we acknowledge that we effectively eliminate the need for related variables including surplus energy costs, surplus cost base year and surplus escalation rate. Most utilities in the northwest are experiencing intermittent and seasonal shortages. The utilities before us are just now beginning to admit that they have capacity needs as well as energy needs. We find it appropriate to create an avoided cost that contains the full value for both energy and capacity.

Initial Year Fuel Costs ($/MMBtu)

Fuel costs are a component in both the fueled rates and non-fueled rates available to QFs. The rate for both fueled and non-fueled projects includes a levelized capital cost component. Non-fueled rates also include a levelized fuel component – locking in an assumed rate of inflation for the life of the contract. Fueled rates and the starting fuel price for non-fueled rates are adjusted each July 1 and are based on the average monthly gas price at Sumas, Washington during the previous calendar year. Non-fueled rates escalate the starting fuel price at a fixed rate over a 30-year plant life.

Idaho Power suggests that only two variables need be addressed in these proceedings to get avoided costs to a level that is accurate or realistic, i.e., (1) current year fuel costs and (2) fuel escalation rate. With a combined cycle combustion turbine as the SAR, fuel and associated variable costs typically comprise more than two-thirds of the total power costs making up avoided costs. This year's annual adjustment included prices from the 2000-2001 period of extreme market volatility when gas prices in the northwest went to extremely high levels. A change in the way the fuel cost component is computed for non-fueled rates is necessary to avoid the effect of locking in a single year of extreme gas prices for the entire contract length.

Alternative methods proposed for providing a starting gas price or current year fuel costs included historical averages, historical trend lines and future market projections, i.e., (1) a five-year rolling average of historic prices, (2) a five-year average consisting of two years historic and three years forecast, (3) the contract price of a one-year strip of power beginning November 1, (4) a seven-year historic average with high and low years discarded, (5) a three-year average, two and half years historic and one-half year projected, and (6) a combination three-year look back and five-year look forward. The only thing all parties agreed to was the inappropriateness of using the current year Sumas numbers which captured the 2000-2001 price volatility.

Idaho Power is of the opinion that a price based on something that is actual or known and measurable is preferable to something in a forecast. The problem with forward prices, it contends, is that they are somewhat volatile and include a premium – anyone who agrees to sell something at a fixed price has to charge more than one feels the price is going to be to earn a profit, i.e., to cover the risk premium. The relevant initial gas price, Idaho Power contends, is that which is most representative of current natural gas prices, not an average of several past years. Unless the present period appears to be one of very high or very low prices, Idaho Power contends that the principle ought to be to use the year's current data and price forecasts. Such a process, it was noted, would require an annual review as to whether gas prices are "normal."

The danger perceived in using a five-year average was that any year might include an outlier or market aberration. The alternative historic seven year average excluding high and low was seen to address this problem but was also perceived to be fallible to the extent that high and low prices were cyclical and actually part of the historic symmetry.

The Commission is persuaded that a reasonable method for calculating a starting gas price is to move away from Sumas and adopt a fuel cost from the draft Fifth Northwest Conservation and Electric Power Plan, April 25, 2002 of the Northwest Power Planning Council. Reference Idaho Power Exhibit 610. The Power Council produces five different levels or forecasts of statistical probabilities of occurring (low, medium-low, medium, medium-high and high). Specifically, we adopt the NWPCC medium 2002 forecast of $3.75/MMBtu calculated in the manner proposed by IEPI witness Trippel, i.e., a simple arithmetic average of nominal prices for the years 2000 through 2002 to arrive at an initial year (2002) medium forecast price. (Source Reference IEPI Exhibit 603, Tr. p. 464; IPCo Exhibit 610, NWPPC Forecast App. D p. F-1.) In doing so, we express confidence in the source and the use of a medium forecast which we believe has the highest probability of being right. We acknowledge that the Power Council does not issue its forecast on a regular basis. This will preclude a regular updating of the fuel price. Although annual updates for starting gas prices have worked well in the past, we do not consider an annual update to be an absolute necessity. Natural gas prices can be updated when a new NWPPC forecast becomes available. A proceeding to review in the starting gas price can also be initiated at any time by the Commission on its own motion or by petition of any utility or QF.

The current fuel price escalation rate is 6%. The escalation rate has a truly long-lasting impact. It was suggested that the best forecast of price escalation is that which has the highest probability of being right, a medium forecast being preferable to a medium-high or high forecast. Idaho Power witness Pesaeu, Tr. p. 637. Use of a single forecast from DOE/EIA as recommended by Staff was criticized as having greater fallibility than a forecast such as the Northwest Power Planning Council's Fuel Price Forecast which relies upon several independent forecasts including DOE/EIA. Staff's objection to use of NWPPC is that the forecasts are not issued on a regular basis and there is no certainty that they will be issued any differently in the future. Staff also noted that the problem with an attempt to collect, compile and calculate an average based on separate independent forecasts is that the forecasts are issued at different times and do not cover the same periods. Idaho Power recommended use of the DRI—WEFA Group's long-term gas escalator. Reference Tr. p. 56. The Commission finds the existing escalation rate of 6% to be unreasonably high for a fuel price escalator for non-fueled contracts. We find it reasonable to adopt the NWPPC estimate of 2.6% nominal rate as calculated using Mr. Trippel's methodology and NWPPC numbers for medium forecast. The escalation rate we approve is a significant downward correction but is high enough to reasonably reflect continued uncertainty in gas prices and supply.

SAR Generic Variable Costs

Apart from fuel costs, there are three primary cost components to the surrogate avoided resource, (1) capital costs, (2) fixed O&M, and (3) variable O&M. Capital costs are based on the initial plant construction costs amortized over the 30-year life of the plant at the utility's weighted cost of capital. O&M costs are based on an initial year estimate that is escalated at a fixed rate over the life of the plant. As proposed by a number of parties, the values of many of the variables under consideration can continue to be drawn from the plant cost data provided by the Generating Resources Advisory Committee (GRAC) of the Northwest Power Planning Council.

In 1996, the Commission in Order No. 25882 adopted a General Electric Frame 7FA 230 MW combined cycle combustion turbine (1 x 1 configuration) as the surrogate avoided resource (SAR). Values for the equipment related variables were drawn from GRAC. A question raised in this case is whether the Commission as part of its review of the variable rates should continue basing cost data on the GE Frame 7FA (1 x 1 configuration) or instead change to the GE Frame 7FB (2 x 1 configuration), a larger 490 MW CCCT. The larger unit and configuration was represented to reflect more current technologies and efficiencies. The Power Planning Council provides current cost data for both turbines and configurations.

The generic variable costs we find appropriate and approve are the Staff proposed NWPPC draft Fifth Power Plan – GRAC updated numbers for the GE Frame 7FA (1 x 1 configuration) with plant cost adjustments for approximate AFUDC that would be required if a plant were to be constructed and heat rate adjusted for elevation. We find that the smaller configuration is a size that better matches the needs of at least two of the three utilities in this case, Idaho Power and Avista, as evidenced by base-load generating units recently constructed or proposed by those utilities or their affiliates. (Coyote Springs for Avista; Garnet for Idaho Power). The approved values are as follows:

Plant Cost	$679/kW	$624 + $55 adder for AFUDC
Fixed O&M	$10.70/kW	
Variable O&M	2.80 mil/kWh	
Heat Rate	7100 Btu	6980 w/adjustment for elevation
Base Year of SAR Cost	2000	
Base Year O&M Expenses	2000	
SAR Plant Life	30 Years (no change)	
SAR Capacity Factor	92% (no change)	

We find it reasonable to update and approve the following Staff-proposed escalation rates derived from the NWPPC's Fifth Power Plan preliminary data which forecasts a 0.6 percent real decrease in combined cycle plant costs adjusted upwards by a 2.70 percent inflation rate from DOE/EIA Annual Energy Outlook 2002:

SAR Construction Costs	2.10%	(0.6%) real decrease in combined cycle plant costs + 2.70% inflation adjustment
Tilting Rate	2.10%	" "

We also find reasonable an escalation rate for O&M set at 2.7%, the same inflation rate from DOE/EIA's Annual Energy Outlook.

O&M	2.70%	DOE/EIA Annual Energy Outlook 2002—general inflation rate*

*Annual Energy Outlook 2002, Table A20 Macroeconomic Indicators, GDP Chain – Type Price Index, Annual Growth 2000-2020; Tr. p. 578.

Utility Specific Variables

IEPI on rebuttal recommends that 3% be added to each utility's capital carrying charge (currently 12.424% for Idaho Power, 11.813% for Avista, and 12.600% for PacifiCorp) to reflect difficulty in obtaining financing for power plants in the current market. Reference Exhibit 608, Affidavit of Darrel Anderson, Vice President and Chief Financial Officer of IdaCorp, Inc. submitted in Idaho Power Garnet Case, IPC-E-01-42. In cross-examination it was clarified that the statement attributed to Mr. Anderson related specifically to the financing of merchant power plants, not utility rate-based generation. Reference Tr. p. 506. The Commission is persuaded that the distinction is relevant. We find no reason on the facts presented to modify the utilities' capital carrying charges, nor do we in this case modify any of the other relevant utility specific variables used in calculation of avoided cost rates.

Utility Avoided Costs

Having selected the generic variable values that we find to be reasonable, the 20-year levelized non-fueled avoided cost rates of Idaho Power, Avista and PacifiCorp for purchases from eligible QFs are: 47.43 mils/kWh Idaho Power, 46.97 mils/kWh Avista, and 47.35 mils/kWh PacifiCorp, as more specifically detailed in Attachment B to this Order. We find the purchase rates to be just and reasonable, to be in the public interest and to fairly represent the avoided costs of each utility. Reference 18 C.F.R. § 292.101(6); 292.304. It is the Commission's belief that in issuing this Order we are establishing a platform for avoided cost pricing that is reasonable and will appropriately reflect the avoided cost of each utility into the future.

CONCLUSIONS OF LAW

The Idaho Public Utilities Commission has jurisdiction over Avista Corporation dba Avista Utilities, Idaho Power Company, and PacifiCorp dba Utah Power & Light Company, electric utilities, pursuant to the authority and power granted it under Title 61 of the Idaho Code, and the Public Utility Regulatory Policies Act of 1978 (PURPA).

The Commission has authority under PURPA and implementing regulations of the Federal Energy Regulatory Commission (FERC) to set avoided costs, to order electric utilities to enter into fixed term obligations for the purchase of energy from qualified facilities, and to implement FERC rules.

ORDER

In consideration of the foregoing and as more particularly described, IT IS HEREBY ORDERED and the Commission on reconsideration does hereby approve changes to generic variables in avoided cost methodology (modification and/or elimination) as detailed in Attachment A to this Order.

IT IS FURTHER ORDERED and the Commission with the changes approved above does hereby approve the resultant fueled and non-fueled avoided cost rates for Idaho Power Company, Avista Corporation, and PacifiCorp as detailed in Attachment B to this Order.

IT IS FURTHER ORDERED and the Commission reaffirms the changes to contract length for QFs smaller than 10 MW approved pursuant to the Petitions for Reconsideration filed by J.R. Simplot Company and Earth Power Resources, Inc. in Order No. 29069.

THIS IS A FINAL ORDER ON RECONSIDERATION. Any party aggrieved by this Order or other final or interlocutory Orders previously issued in this Case No.GNR-E-02-1 may appeal to the Supreme Court of Idaho pursuant to the Public Utilities Law and the Idaho Appellate Rules. See *Idaho Code* § 61-627.

DONE by Order of the Idaho Public Utilities Commission at Boise, Idaho this 26th day of September 2002.

PAUL KJELLANDER, PRESIDENT

MARSHA H. SMITH, COMMISSIONER

DENNIS S. HANSEN, COMMISSIONER

ATTEST:

Jean D. Jewell
Commission Secretary

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AVOIDED COST GENERIC VARIABLES

DATA TYPE	CURRENT VARIABLES	NEW VARIABLES
SURPLUS ENERGY COST (mil/kWh):	19.00	Abandon
SURPLUS COST BASE YEAR:	1994	Abandon
FIRST DEFICIT YEAR:	2010/1998/1999	Abandon
"SAR" PLANT LIFE (YEARS):	30	No Change
"SAR" PLANT COST ($/kW):	$667	$679
BASE YEAR OF "SAR" COST:	1994	2000
"SAR" CAPACITY FACTOR (%):	92%	No Change
"SAR" FIXED O&M ($/kW):	$7.43	$10.70
"SAR" VARIABLE O&M (mil/kWh):	1.65	2.80
CURRENT YR FUEL COST ($/MMBtu):	$5.23	$3.75
BASE YEAR, O&M EXPENSES:	1994	2000
ESCALATION RATE; "SAR" (%):	3.60%	2.10%
ESCALATION RATE; SURPLUS (%):	4.50%	Abandon
ESCALATION RATE; O&M (%):	3.21%	2.70%
ESCALATION RATE; FUEL (%):	6.0% nom	2.6%
"TILTING" RATE (%):	3.60%	2.10%
HEAT RATE (Btu/kWh):	7350	7100

IDAHO POWER COMPANY
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	39.81	40.81	41.83	42.88	43.95	45.05	2002	39.81
2	40.29	41.30	42.33	43.39	44.47	45.59	2003	40.81
3	40.76	41.78	42.82	43.89	44.99	46.12	2004	41.83
4	41.22	42.25	43.31	44.39	45.50	46.64	2005	42.88
5	41.67	42.72	43.78	44.88	46.00	47.15	2006	43.95
6	42.12	43.17	44.25	45.36	46.50	47.66	2007	45.05
7	42.56	43.62	44.71	45.83	46.98	48.16	2008	46.17
8	42.99	44.06	45.17	46.30	47.45	48.64	2009	47.33
9	43.41	44.49	45.61	46.75	47.92	49.12	2010	48.51
10	43.82	44.92	46.04	47.19	48.37	49.59	2011	49.73
11	44.22	45.33	46.46	47.63	48.82	50.04	2012	50.97
12	44.62	45.73	46.88	48.05	49.25	50.49	2013	52.25
13	45.00	46.13	47.28	48.47	49.68	50.92	2014	53.56
14	45.38	46.51	47.68	48.87	50.09	51.35	2015	54.90
15	45.74	46.89	48.06	49.26	50.50	51.76	2016	56.28
16	46.10	47.25	48.44	49.65	50.89	52.17	2017	57.69
17	46.44	47.61	48.80	50.02	51.27	52.56	2018	59.13
18	46.78	47.95	49.15	50.38	51.65	52.94	2019	60.62
19	47.11	48.29	49.50	50.74	52.01	53.31	2020	62.14
20	47.43	48.61	49.83	51.08	52.36	53.67	2021	63.70
							2022	65.29
							2023	66.93
							2024	68.61
							2025	70.33
							2026	72.10
							2027	73.91

IDAHO POWER COMPANY
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	13.19	13.49	13.80	14.12	14.44	14.78	2002	13.18
2	13.33	13.64	13.95	14.27	14.60	14.94	2003	13.49
3	13.48	13.79	14.10	14.43	14.76	15.10	2004	13.80
4	13.62	13.93	14.25	14.58	14.91	15.26	2005	14.11
5	13.75	14.07	14.39	14.73	15.06	15.41	2006	14.44
6	13.89	14.21	14.54	14.87	15.21	15.56	2007	14.77
7	14.02	14.34	14.67	15.01	15.36	15.71	2008	15.11
8	14.15	14.48	14.81	15.15	15.50	15.86	2009	15.46
9	14.28	14.61	14.94	15.29	15.64	16.00	2010	15.82
10	14.40	14.73	15.07	15.42	15.78	16.14	2011	16.18
11	14.52	14.86	15.20	15.55	15.91	16.28	2012	16.55
12	14.64	14.98	15.33	15.68	16.04	16.41	2013	16.94
13	14.76	15.10	15.45	15.80	16.17	16.54	2014	17.33
14	14.87	15.21	15.56	15.92	16.29	16.67	2015	17.73
15	14.98	15.33	15.68	16.04	16.41	16.79	2016	18.14
16	15.09	15.43	15.79	16.15	16.53	16.91	2017	18.55
17	15.19	15.54	15.90	16.27	16.64	17.02	2018	18.98
18	15.29	15.64	16.00	16.37	16.75	17.14	2019	19.42
19	15.39	15.74	16.11	16.48	16.86	17.25	2020	19.87
20	15.48	15.84	16.21	16.58	16.96	17.35	2021	20.33
							2022	20.80
							2023	21.28
							2024	21.77
							2025	22.28
							2026	22.80
							2027	23.32

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	15.48 + 26.63
2-20	15.48 + 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	13.18 + 26.63
2	13.49 + Adjustable component in year 2003
3	13.80 + Adjustable component in year 2004
4	14.11 + Adjustable component in year 2005

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

PACIFICORP
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	40.04	41.04	42.07	43.12	44.20	45.30	2002	40.04
2	40.52	41.53	42.57	43.63	44.72	45.84	2003	41.04
3	40.98	42.01	43.06	44.13	45.24	46.37	2004	42.07
4	41.44	42.48	43.54	44.63	45.74	46.89	2005	43.12
5	41.89	42.94	44.01	45.11	46.24	47.39	2006	44.20
6	42.33	43.39	44.47	45.58	46.72	47.89	2007	45.30
7	42.76	43.83	44.92	46.05	47.20	48.38	2008	46.43
8	43.18	44.26	45.36	46.50	47.66	48.85	2009	47.59
9	43.59	44.68	45.79	46.94	48.11	49.31	2010	48.78
10	43.98	45.08	46.21	47.37	48.55	49.76	2011	50.00
11	44.37	45.48	46.62	47.78	48.98	50.20	2012	51.26
12	44.75	45.86	47.01	48.19	49.39	50.63	2013	52.54
13	45.11	46.24	47.39	48.58	49.80	51.04	2014	53.85
14	45.46	46.60	47.77	48.96	50.19	51.44	2015	55.20
15	45.81	46.95	48.13	49.33	50.56	51.83	2016	56.58
16	46.14	47.29	48.47	49.69	50.93	52.20	2017	58.00
17	46.46	47.62	48.81	50.03	51.28	52.57	2018	59.45
18	46.77	47.94	49.14	50.37	51.63	52.92	2019	60.94
19	47.07	48.24	49.45	50.69	51.96	53.26	2020	62.47
20	47.35	48.54	49.75	51.00	52.27	53.58	2021	64.03
							2022	65.64
							2023	67.28
							2024	68.97
							2025	70.70
							2026	72.47
							2027	74.29

PACIFICORP
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	13.42	13.72	14.04	14.36	14.69	15.03	2002	13.41
2	13.56	13.87	14.19	14.52	14.85	15.19	2003	13.72
3	13.71	14.02	14.34	14.67	15.01	15.36	2004	14.03
4	13.85	14.17	14.49	14.82	15.16	15.51	2005	14.36
5	13.99	14.31	14.64	14.97	15.32	15.67	2006	14.69
6	14.12	14.44	14.78	15.12	15.46	15.82	2007	15.02
7	14.25	14.58	14.91	15.26	15.61	15.97	2008	15.37
8	14.38	14.71	15.05	15.39	15.75	16.11	2009	15.72
9	14.50	14.84	15.18	15.53	15.88	16.25	2010	16.09
10	14.62	14.96	15.30	15.66	16.02	16.39	2011	16.46
11	14.74	15.08	15.43	15.78	16.15	16.52	2012	16.83
12	14.86	15.20	15.55	15.91	16.27	16.65	2013	17.22
13	14.97	15.31	15.66	16.02	16.39	16.77	2014	17.62
14	15.08	15.42	15.78	16.14	16.51	16.89	2015	18.03
15	15.18	15.53	15.89	16.25	16.62	17.01	2016	18.44
16	15.28	15.63	15.99	16.36	16.73	17.12	2017	18.87
17	15.38	15.73	16.09	16.46	16.84	17.23	2018	19.30
18	15.47	15.83	16.19	16.56	16.94	17.33	2019	19.75
19	15.56	15.92	16.28	16.66	17.04	17.43	2020	20.20
20	15.65	16.01	16.37	16.75	17.14	17.53	2021	20.67
							2022	21.15
							2023	21.64
							2024	22.14
							2025	22.65
							2026	23.17
							2027	23.71

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	15.65 + 26.63
2-20	15.65 + 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	13.41 + 26.63
2	13.72 + Adjustable component in year 2003
3	14.03 + Adjustable component in year 2004
4	14.36 + Adjustable component in year 2005