Office of the Secretary
Service Date
November 24, 2004

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF AVISTA CORPORATION FOR THE AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC AND NATURAL GAS SERVICE TO ELECTRIC AND NATURAL GAS CUSTOMERS IN THE STATE OF IDAHO.	)	**CASE NOS. AVU-E-04-1 AVU-G-04-1** **ORDER NO. 29638**

On February 6, 2004, Avista Corporation dba Avista Utilities (Avista; Company) filed an Application with the Idaho Public Utilities Commission (Commission) for authority to increase its rates and charges for electric and natural gas service in the State of Idaho.

On October 8, 2004, the Commission issued final Order No. 29602 authorizing Avista to increase its Idaho electric base revenue requirement by $24,716,195 or approximately 16.90%. This increase was offset by disallowances in the Power Cost Adjustment (PCA) coupled with an adjustment in the PCA recovery period and the reduction in the energy efficiency rider. These offsetting adjustments reduced the authorized electric net revenue increase to $3,182,000 or 1.9% of current annual revenue. The Commission also authorized Avista to increase its natural gas revenues by $3,311,000 or approximately 6.38%.

On October 29, 2004, Avista filed a Petition for Reconsideration of Order No. 29602. *Idaho Code* § 61-626. On November 5, 2004, Potlatch Corporation filed an Answer and Cross Petition for Reconsideration. Also filed on November 5, was Commission Staff's Reply to Avista's Petition for Reconsideration. The Commission in this Order approves the technical computation errors identified by the Company and agreed to by Staff and denies the remaining relief sought in the Company's Petition for Reconsideration and Potlatch's Cross Petition for Reconsideration.

The respective Petition, Answer and Cross Petition, and Reply can be summarized as follows:

Avista Petition for Reconsideration

Avista contends that certain portions of the Commission's Order No. 29602 are unreasonable, unlawful, erroneous and not otherwise in conformity with the facts of record and/or the applicable law, resulting in a revenue requirement and rates that are confiscatory.

I. Deal A Disallowance

Avista contends that the Commission's disallowance of one-third of the Idaho jurisdictional share of Power Cost Adjustment (PCA) Coyote Springs 2 (CS2) Deal A losses fails to recognize evidence of record and was otherwise unreasonable.

In Avista PCA Order No. 29377, Case No. AVU-E-03-6, the Commission deferred a PCA recovery decision regarding the Company's acquisition and later sale at a loss of natural gas to fuel the Coyote Springs 2 (CS2) combined cycle combustion turbine. CS2 was initially scheduled for testing in early 2002 and was expected to be commercially available in July 2002. As it turns out, at the time the gas was scheduled for delivery CS2 was not operational nor was it economical to use the gas purchased at the Company's other facilities. Instead Avista simply purchased its power needs on the electric market and sold the Deal A gas back into the gas market at a loss because gas prices had declined.

As reflected in the Commission's Order, Deal A consisted of two transactions of 10,000 dth/day each, for a 36 month delivery term (November 1, 2001 through October 30, 2004), that were entered into for the purpose of hedging or fixing, the natural gas price of index-based physical purchases for the period of November 1, 2001, through October 31, 2004. One transaction was entered into on April 11, 2001 at a price of \$6.7525/dth and the second transaction was entered into on May 2, 2001 at a price of \$6.50/dth. The price for October 2004 gas was locked-in for three and one-half years into the future. The system loss attributable to Deal A gas through May 31, 2004 was \$47,936,000. The Idaho jurisdictional amount disallowed by the Commission was \$4,771,550.

On reconsideration Avista contends, as previously indicated at hearing by its witness Robert Lafferty, that the combination of net system variability and high/volatile energy prices, posed a "significant economic risk" to the Company. The Company in response elected to hedge a portion of the monthly deficit associated with the combined variability of loads and hydroelectric generation conditions.

Avista points out that the Commission's own Staff was quite clear and unambiguous in its recommendation to disallow only Deal B hedge losses. As Staff witness Hessing indicated, "Deal A hedges were not done with an Avista affiliate, but Deal B hedges were. Also, the Deal A gas purchase did not put the Company over the long limit contained in its Risk Policy. . . ." Tr. at 1270. Citing Commission Staff, Avista contends that Deal A was well within the

Company's risk parameters or "protocols"; provided the necessary gas supply, at a fixed cost, to fuel the needed Coyote Springs 2 generation plant; and was not "speculative" because it aligned the Company's loads and resources for the future and within the limits that were set in the Company's Risk Policy. Tr. at 1270, 1271-72, 1308-09.

Avista includes as an Appendix to its Petition a load resource position summary based on 90% confidence interval planning that it contends demonstrates that Deal A if looked at alone, was well within and consistent with the Company's resource planning criteria. Tr. Exh. 7, Sch. 26, p. 2. (A 90% confidence interval represents a 5% chance that the Company would have to purchase some amount of energy above a specific megawatt amount for a given month.)

Avista disputes the Commission's finding that the Company's supporting analysis appeared to be "cobbled together" after the fact, citing Lafferty testimony describing the Company's analysis. Avista contends that the record reflects that the Company conducted extensive modeling of its load/resource balance prior to entering into the hedge transactions and also undertook a comparative analysis of the cost to generate power at the hedged price of gas compared to electric power prices available at the time.

Avista contends that fixing the price of index-based physical purchases through the Deal A hedged transactions was also consistent with its electric Integrated Resource Planning (IRP) objectives.

The Company concludes that when one looks to the "prudence" of decision making at the time the decisions were made, the evidence demonstrates that (a) an analysis of the load/resource balance with Deal A had been conducted, demonstrating that even with Deal A, the Company was in a resource deficit position, and (b) that an examination of forward prices, at the time, demonstrated that the hedged natural gas fuel would result in generation costs of between \$38/MWh to \$48/MWh – well below the higher-priced power available in the market, and (c) that Deal A hedged transactions were consistent with resource planning objectives and Risk Policy guidelines or protocols. The record, the Company contends, demonstrates that both the need for the hedge transactions and the cost of such transactions were, in fact, analyzed before entering into the transactions. Analysis and documentation pertaining to both the load/resource deficits and the forward market prices did exist, the Company states, before it entered into the transactions.

Potlatch Cross Petition

Potlatch in its Cross Petition contends as both a matter of law and equity, that the entirety of the Deal A costs should be disallowed, citing the "just and reasonable" standard of *Idaho Code* § 61-301. The "just and reasonable" rate standard, Potlatch contends, necessarily assumes reasonable managerial competence and prudence. If a utility spends money unnecessarily or imprudently, Potlatch contends it should not be allowed to recover such expenditures. The underlying physical purchases for Deal A had already been made, Potlatch states. What Deal A, Potlatch contends, did was to lock-in an immediate gamble on the price direction of the natural gas futures market. The 36-month length of the Deal A hedges and the financial exposure created, Potlatch contends, was, as reflected in its testimony of Potlatch witness Dr. Dennis Peseau, unprecedented for Avista, and for the electric industry as a whole. Potlatch contends that the risk assumed in Deal A was a derivative risk and that the risk was assumed without any formal cost benefit analysis. The failure of the Company to evaluate it as an exposure separate and distinct from the physical purchase of gas, Potlatch contends, was not only imprudent, it was specifically prohibited by Avista's Risk Management Policy. Citing Risk Management Policy:

> Any incremental market exposure created from the use of derivatives is inconsistent with the risk management objectives of this Policy and is not permitted. The use of derivatives exposes Avista Corp. to risks similar to risks of physical products, and may have additional liquidity, settlement, legal, and systematic risk attributes. Even the proposed use of derivatives that would hedge risks should be assessed against these additional risks, and such use is permitted only to the extent that the expected benefit is considered to outweigh these risks. Tr. at 956 (Confidential).

Potlatch contends that the Commission's disallowance of one-third of Deal A's cost is a wholly inadequate remedy. Deal A, it states, was imprudent and "not permitted" under the Company's Risk Policy and it should be similarly "not permitted" for ratemaking purposes. The Commission, Potlatch states, can have no basis for finding that any portion of the costs associated with Deal A can be passed onto ratepayers as a necessary and prudent expenditure. The Commission, Potlatch contends, simply does not have authority to attempt a middle approach that attempts to give something to both the utility shareholders and its ratepayers. Deal A losses, it concludes, must be left with the utility whose incompetence and recklessness caused their incurrence.

Commission Findings

The Commission has reviewed the filings of record in Case Nos. AVU-E-04-1/AVU-G-04-1 including Avista's Petition for Reconsideration, Potlatch's Answer and Cross Petition for Reconsideration, Commission Staff's Reply, the underlying transcript of proceedings and our Order No. 29602. We have also reviewed recent customer comments filed with the Commission opposing further rate increases.

Contrary to Avista's contention, the Commission did recognize evidence of record. The Commission weighed all the evidence including conflicting evidence and reached its conclusions.

Despite Avista's contention to the contrary, as reflected in the record, the Commission finds that Deal A did not conform to established protocols. There were no Commission-approved protocols in place for electric side gas procurement. The transaction both in length (36 months) and financial exposure was unprecedented for Avista and was accompanied by little supporting analysis and paper trail, of the sort relied upon by the Commission's auditing Staff for utility gas Benchmark transactions. The Deal A hedge transaction was a financial derivative contract. The Company took a price view using derivatives that despite the Company's contention to the contrary was clearly not permitted under its internal Risk Management Policy. Nor was the financial transaction, we find, the sort of physical transaction clearly authorized in the Company's electric Integrated Resource Plan.

The Commission in its Order prefaces its discussion of Deal A losses with a consideration of what it determined to be a threshold issue, the propriety of Avista's transactions with Avista Energy. Contrary to Avista's contention, the Commission's findings regarding no "operating protocol" being established for transactions between Avista Energy and Avista's electric operations was not a finding of deficiency as to Deal B alone – it was also a finding regarding Deal A. The need for operating protocols governing conduct between the utility and its unregulated affiliate exists whether or not Avista Energy was acting as a counter-party. Although not a counter-party to the Deal A transaction, Avista Energy brokered the deal. Thus, contrary to Avista's contention, Deal A hedge losses <u>cannot</u> be viewed separate and apart from any Avista Energy involvement.

The Company's Risk Management Policy, we find, was an internal Company policy intended to provide transactional guidance. It was not an operating protocol filed with or approved by the Commission. The Benchmark Mechanism, on the other hand, is an operating protocol approved by the Commission; but it exists only on the gas side, not the electric.

The Company's statements regarding the consistency of Deal A hedge transactions with its risk policy guidelines and resource planning objectives are not sufficient to justify transactions that were otherwise engaged in without an underlying Commission approved operating protocol and agency agreement. The Company's actions exposed utility customers to the risk associated with the Company's non-regulated subsidiary operations. Deal A was highly irregular and apart from any other transactions made by Avista. The fact that the Company failed to purchase gas with the same kind of long-term deals for its gas customers that it did for its electric customers, we find, also demonstrates the Company's inconsistency.

Potlatch contends that the Commission has no choice but to deny recovery of Deal A amounts. The Commission disagrees. While Avista was certainly engaging in objectionable transactions in Deal A and B, the transactions themselves were not expressly prohibited by Commission Order or established protocol. There was no Order; there was no protocol on the electric side to provide guidance in affiliate transactions. It is a grey area, not black and white. The Commission has a joint obligation to the utility and its customers. The Commission has authority under *Idaho Code* §§ 61-501 and 61-301 to assess the reasonableness of the Company's actions and to determine a reasonable level of cost recovery.

Consequently, we reaffirm our decision to disallow a portion of the losses associated with Deal A.

Deal A -- Miscalculations

Avista in its Petition also contends that there are four miscalculations related to the determination of Deal A losses that need to be corrected. The cumulative reduction for the four Company-identified miscalculations is $2,648,937. Incorporating these four adjustments to the calculation of gas losses results in a Deal A disallowance of $2,122,937. This compares to the Deal A disallowance of $4,771,550 in Order No. 29602.

A. <u>Company Contention</u>: Staff Exhibit 141 relied upon by the Commission, has the wrong number of days for the months of July 2003 through May 2004. This error overstates the loss calculation for Deal A. ... The Company-proposed adjustment is $91,035.

Staff Reply

Staff in its Reply concurs with the Company-proposed corrections to the wrong number of days in the months that were included in Deal A calculations.

Commission Findings

We accept on reconsideration the corrections for number of days in the month included in Deal A calculations.

B. Company Contention: The Staff Exhibit No. 141 calculation of Deal A gas losses includes an incorrect calculation of the Deal A gas profitably burned for the months of November 2003 through May 2004. It included only one-half of the Deal A gas profitably burned and should have included all of it, since Deal B had ended October 31, 2003. The Company-proposed adjustment is $35,819.

Staff Reply

Staff in its Reply concurs with the Company-proposed corrections to the calculation for gas profitably burned for the period November 2003 – May 2004.

Commission Findings

We accept on reconsideration the corrections for Deal A gas profitably burned for the period November 2003 – May 2004.

C. Company Contention: The Commission-ordered disallowance of $4,771,550 is based on "one-third" of the Deal A losses. The Company has already absorbed 10% of the total Deal A losses through the 90%/10% sharing feature of the PCA. The effective disallowance is therefore 40% of the total losses—not the "one-third" disallowance ordered by the Commission. The Company proposed adjustment is $1,060,344.

D. Company Contention: The Deal A disallowance is based on total Deal A losses for the period November 2001 through May 2004. The losses in the period November 2001 through June 2002, however, had previously been authorized by the Commission for PCA recovery. To order a disallowance based on losses that were previously approved for recovery would, the Company contends, constitute retroactive ratemaking. The Company proposed adjustment is $1,461,415.

Staff Reply – C & D

The methodology used to calculate Deal A disallowance, Staff contends, is clearly specified in Order No. 29602 on page 46:

> Deal A losses through May amounted to $47,936,010 on a system basis; $15,905,167 on an Idaho jurisdictional basis. With 90/10 sharing the Idaho PCA amount related to Deal A losses is $14,314,651. Of that amount $5,636,885 was previously authorized for PCA recovery (July 1 - June 2002). Based on our consideration of the record and Deal A findings, the Commission finds it reasonable to exclude or disallow one-third of the Idaho system Deal A losses, or $4,771,550.

The table below, Staff states, duplicates the Commission specified methodology. The total amount of Deal A losses, at the system level, is multiplied by the allocation factor for the Idaho Jurisdiction, to come up with the Idaho Jurisdictional amount of the total Deal A losses. This amount is then adjusted to reflect the 10% sharing mechanism in the PCA calculation and the ratepayer portion of the losses. The ratepayer portion is then divided by three to arrive at the disallowance ordered by the Commission. Using the same methodology with corrections incorporating the proper number of days and the proper amount of gas profitably burned results in a Deal A disallowance of $4,608,452.

	Commission Order	Commission Order With Corrections
1. Losses already recovered on Deal A:	$18,876,448	$18,876,448
2. Losses deferred for recovery on Deal A:	$29,059,562	$27,421,045
3. Total System losses on Deal A:	$47,936,010	$46,297,493
4. Jurisdictional Factor:	33.18%	33.18%
5. Idaho Jurisdictional Portion of Deal A Losses:	$15,905,168	$15,361,508
6. 10% Shareholder PCA Portion of Deal A Losses:	$ 1,590,517	$ 1,536,151
7. Ratepayer Portion of Deal A Losses:	$14,314,651	$13,825,357
8. One Third of Ratepayer Portion of Deal A Losses:	$ 4,771,550	$ 4,608,452
9. Disallowance Amount of Deal A Losses:	$ 4,771,550	$ 4,608,452

With respect to miscalculation items C and D described above, Staff contends that the Company's calculation of the Deal A disallowance is not consistent with the Commission's Order. Rather than using total Deal A losses of $46,297,493 (as corrected) to calculate the disallowance as specified by the Commission, the Company, Staff notes, uses only Deal A losses of $27,421,045 (as corrected) currently deferred for recovery. The Company then improperly takes one third of the unrecovered Idaho jurisdictional Deal A losses before applying the 10 percent PCA sharing. This is in contrast, Staff contends, to the Commission Order that applies the 10% sharing first to the Idaho Jurisdictional losses and then takes one third of the remaining total to establish the disallowed amount.

The Company, Staff states, has calculated the Deal A disallowance in the following manner:

Deal A losses deferred for recovery:	$27,421,045
Jurisdictional Factor:	33.18%
Idaho Jurisdictional Portion of Unrecovered Deal A Losses:	$ 9,098,303
One Third of Idaho Jurisdictional portion of Unrecovered Deal A Losses:	$ 3,032,768
Less 10% of Idaho Jurisdictional portion of Unrecovered Deal A Losses:	$ 909,830
Company Disallowance Amount of Deal A Losses	$ 2,122,937

The Company, Staff contends, perceives inclusion of the $18,876,448 in the Deal A disallowances calculation to be retroactive ratemaking and therefore, removes the amount to correct what it characterizes as a calculation error. However, the Commission Order, Staff notes, clearly states ". . . $5,636,885 was previously authorized for PCA recovery (July 1–June 2002)." The $5,636,885 is the Idaho jurisdictional ratepayer share of $18,876,448. Total Deal A losses were simply used in the Order to establish what amount of the additional losses was subject to recovery through the PCA and what amount was not. Prior amounts recovered in rates are not being reversed.

Commission Findings

We reject Avista's characterization of the disallowance methodology and stand by the clear language of the Order that sets out the process used to establish the disallowed amount. Contrary to Avista's contention, we have not required a refunding of Deal A losses previously approved for recovery. While our mathematical calculation is based on the total Deal A losses through May 2004, we find the Deal A disallowance dollar amount to be otherwise reasonable as a reduction to the unrecovered Deal A loss amount.

In summary, the net effect of the proposed corrections A and B is an increase in Deal A loss recovery through the PCA of $163,098 after applying the Commission ordered disallowance methodology.

II. Boulder Park

The Commission's disallowance of costs associated with Boulder Park, Avista contends, was excessive and unduly harsh.

The Commission in Order No. 29602 regarding Boulder Park found a 53% construction cost overrun to be unreasonable. The original cost estimate in May 2001 was $21 million. The total actual cost upon completion was $31.9 million. The Commission found it reasonable to limit the authorized rate base amount for Boulder Park to the project construction estimate plus a 15% contingency, or $24,150,000. The Idaho jurisdictional share of the disallowance is $2.6 million. The Company contends that the disallowance should not exceed the 10% of final project costs recommended by Staff, $1.1 million (Idaho jurisdictional share).

Potlatch Answer

Regarding Boulder Park, Potlatch supports in its Answer the Commission's disallowance. The simple fact, Potlatch states, is that Boulder Park costs were wildly excessive when compared to any reasonable cost overrun possibilities. Clearly if Boulder Park had been purchased from an independent third party contract, Potlatch posits, it would have been unreasonable for Avista not to cap any potential cost overruns by contract. Similarly, Potlatch contends, it is not unreasonable for the Commission to impose an overrun limitation on plants built by Avista.

Commission Findings

The Commission in Order No. 29602 found that Avista should be held to a higher standard than recommended by Staff. Ratepayers, we found, should not be asked to pay for what we continue to find to be a Company learning experience. The reasonableness of our disallowance is not the percentage of total disallowed, but the percentage of cost overrun allowed.

III. Pension Expense Adjustment (Electric/Gas)

Avista in its Petition identified a technical correction to the adjustment of the Company's pension cost. The identified changes are needed to correctly allocate the "system" corporate level of pension expense to utility operations prior to applying the Idaho jurisdictional allocation factors. The correction results in a $46,411 increase in the electric revenue requirement and an $11,422 increase in the natural gas revenue requirement. Avista Petition, Attachment D.

Staff Reply

Staff agrees with the technical correction proposed by the Company.

Commission Findings

The Commission accepts the Company-proposed pension expense adjustments.

CONCLUSIONS OF LAW

The Idaho Public Utilities Commission has jurisdiction over this Petition and Avista Corporation dba Avista Utilities, an electric and natural gas utility, pursuant to the authority and power granted under Title 61 of the Idaho Code and the Commission's Rules of Procedure, IDAPA 31.01.01.000 *et seq*.

ORDER

In consideration of the foregoing and as more particularly described above, IT IS HEREBY ORDERED and the Commission by this Order on Reconsideration of final Order No. 29602 in Case Nos. AVU-E-04-1 and AVU-G-04-1 approves the Deal A technical corrections for proper number of days and the proper amount of gas profitably burned.

IT IS FURTHER ORDERED and the Commission by this Order approves the technical corrections to the natural gas and electric pension expense adjustments.

IT IS FURTHER ORDERED and the Commission by this Order denies reconsideration of the underlying disallowance for PCA Deal A losses and Boulder Park cost overruns and reaffirms its related findings in Order No. 29638.

THIS IS A FINAL ORDER ON RECONSIDERATION. Any party aggrieved by this Order or other final or interlocutory Orders previously issued in this Case Nos. AVU-E-04-1 and AVU-G-04-1 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 24th day of November 2004.

PAUL KJELLANDER, PRESIDENT

Comm. Smith was Out of the Office this Date
MARSHA H. SMITH, COMMISSIONER

DENNIS S. HANSEN, COMMISSIONER

ATTEST:

Jean D. Jewell
Commission Secretary

bls/O:AVUE0401_AVUG0401_sw8