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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 NO. AVU-E-09-01 DIRECT TESTIMONY OF WILLIAM G. JOHNSON

FOR AVISTA CORPORATION

(ELECTRIC ONLY)

I. INTRODUCTION

Q. Please state your name, business address, and present position with Avista Corporation.

A. My name is William G. Johnson. My business address is 1411 East Mission Avenue, Spokane, Washington, and I am employed by the Company as a Wholesale Marketing Manager in the Energy Resources Department.

Q. What is your educational background?

A. I graduated from the University of Montana in 1981 with a Bachelor of Arts Degree in Political Science/Economics. I obtained a Master of Arts Degree in Economics from the University of Montana in 1985.

Q. How long have you been employed by the Company and what are your duties as a Wholesale Marketing Manager?

A. I started working for Avista in April 1990 as a Demand Side Resource Analyst. I joined the Energy Resources Department as a Power Contracts Analyst in June 1996. My primary responsibilities involve power contract origination and management and power supply regulatory issues.

Q. What is the scope of your testimony in this proceeding?

A. My testimony will 1) identify and explain the proposed normalizing and pro forma adjustments to the October 2007 through September 2008 test period power supply revenues and expenses, and 2) describe the proposed changes to the Power Cost Adjustment (PCA) calculation methodology and the new authorized level of power supply expense for PCA calculation purposes and 3) describe how the Company proposes to track the expense and revenue associated with the Lancaster plant, which will become an Avista Utilities resource beginning January 1, 2010.

Q. Are you sponsoring any exhibits to be introduced in this proceeding?

A. Yes. I am sponsoring Exhibit No. 6, Schedules 1 through 4, which were prepared under my supervision and direction.

Q. Are other company witnesses providing testimony regarding issues you are addressing?

A. Yes. Company witness Mr. Kalich provides detailed testimony on the AURORA model used by the Company to develop short-term power purchase expense, fuel expense and short-term power sales revenue included in my exhibits.

II. Pro Forma Expense Adjustment

Q. Please provide an overview of your pro forma adjustment to power supply expense.

A. The pro forma adjustment to power supply expense involves the determination of revenues and expenses based on the generation and dispatch of Company resources and expected wholesale market power prices as determined by the AURORA model simulation for the pro forma period under normal weather and hydro generation conditions. In addition, adjustments are made to reflect contract changes between test period and the pro forma period. The table below shows total net power supply expense during the test period and the pro forma period. For information purposes only, the power supply expense currently in rates, which is based on a calendar 2009 pro forma period, is also shown.

Power Supply Expense (Not Including Directly Assigned Potlatch Purchase)	System	Idaho Allocation
Power Supply Expense in Current Base Rates (Calendar 2009 pro forma)	$174,849,000	
Actual Oct 07-Sep 08 Power Supply Expense	$180,395,000	
Adjustment to Test Period	$27,645,000	$9,789,095
July 2009 - June 2010 Pro forma Power Supply Expense	$208,040,000	
Increase from Expense in Current Rates	$33,191,000	$11,752,933

The net effect of my adjustments to the test year power supply expense is an increase of $27,645,000 ($208,040,000 - $180,395,000) on a system basis. The Idaho allocation of this adjustment of $9,789,095 is incorporated into the revenue requirement calculation for the Idaho jurisdiction by Company witness Ms. Andrews.

The increase in power supply expense compared to the pro forma level in current base rates is $33,191,000 (system) and $11,752,933 (Idaho allocation). The power supply expense in current base rates is based on a calendar year 2009 pro forma.

Q. What are the major factors driving the increased power supply expense in the pro forma year over the level of power supply expense currently in base rates?

A. The level of power supply expense currently in base rates is $174,849,000 (system number). This expense level is based on a calendar 2009 pro forma period. This compares to the proposed pro forma power supply expense of $208,040,000, an increase of approximately $33.2 million on a system basis and an Idaho allocation of approximately $11.8 million.

This increase in pro forma power supply expense over the expense currently in base rates is based on numerous factors, primarily reduced hydro generation due to the elimination of the rate mitigation adjustment included in the last case and higher retail loads.

Pro forma retail loads are 22.7 aMW higher than loads that current rates are based on. The increased loads are due to two factors. One is the natural increase in retail loads of approximately 14.3 aMW. The other 8.4 aMW of load increase is due to the reduction in Potlatch generation. Because Potlatch generation expense is directly assigned to Idaho, the Potlatch load equivalent to their generation is removed from system loads. The reduction in Potlatch generation has the effect of increasing system loads for rate making purposes, while at the same time reducing the Potlatch power purchase expense directly assigned to Idaho.

Hydro generation is also lower than the level in current base rates. Pro forma hydro generation is 533.3 aMW compared to 563.1 aMW in current base rates, a reduction of 29.8 aMW. This pro forma removes the additional 26.5 aMW of hydro generation incorporated in last year's general rate case as the "rate mitigation adjustment." The remaining reduction in hydro generation is due to the reduction in Mid Columbia purchased hydro generation resulting from the expiration of the Wanapum contract in November 2009.

The table below shows the primary factors driving the increase in power supply expense compared to the level in current base rates.

Power Supply Expense Change July 2009 - June 2010 Pro forma vs. 2009 Pro forma		
Factor	Power Supply Change (System) $millions	Power Supply Change (Idaho) $millions
System Load	$11.0	$3.90
Rate Mitigation Removed	$12.8	$4.53
Settlement Adjustments Removed	$3.1	$1.10
Actual Transactions Mark-to-Model	$4.3	$1.52
Coyote Operating Margin	-$0.5	-$0.18
Other	$2.5	$0.89
Total Pro forma Increase	$33.2	$11.8

III. PRO FORMA POWER SUPPLY EXPENSE

Overview

Q. Please identify the specific power supply cost items that are covered by your testimony and the total adjustment being proposed.

A. Exhibit No. 6, Schedule 1 identifies the power supply expense and revenue items that fall within the scope of my testimony. These revenue and expense items are related to power purchases and sales, fuel expenses, transmission expense, and other miscellaneous power supply expenses and revenues.

Q. What is the basis for the adjustments to the test period power supply revenues and expenses?

A. The purpose of the adjustments to the test period is to normalize power supply expenses for normal weather and hydroelectric generation and to reflect known and measurable changes for the pro forma period that rates will be in effect. Adjustments are also made to reflect contract changes from the test period to the pro forma period.

The AURORA Model dispatches Company resources on an hourly basis and calculates the level of generation from the Company's thermal resources, fuel costs for thermal resources, and the short-term purchases and sales necessary to serve system requirements.

Q. Have any changes been made in the calculation of pro forma power supply costs from the last general rate case?

A. Yes. The primary change made in this general rate case is to include the actual term power and natural gas transactions already entered into for delivery in the pro forma period. Term transactions are monthly and quarterly transactions. This is done to more accurately reflect the actual power supply expense the Company will incur during the pro forma period.

As of November 30, 2008 Avista had entered into 33 forward electric contracts and 8 forward natural gas contracts for delivery in the pro forma period. The electric contracts include 15 physical purchases and 4 physical sales and 14 financial (fixed-for-floating swaps) purchases. The natural gas transactions include 4 purchases and 4 sales.

The mechanics of including actual transactions in the pro forma is to add the physical electric transactions as resources and obligations in the AURORA model and include a mark-to-model adjustment in the pro forma for the financial electric and natural gas transactions. If the actual transactions lower power supply expense (lower purchase costs or higher sales revenue) as compared to the cost produced by the AURORA model, then the lower cost is included in the pro forma expense. If the actual transactions increase power supply expense (higher purchase costs or lower sales revenue) as compared to the cost produced by the AURORA model, then the higher cost is included in the pro forma expense.

The Company's hedging program layers in purchase and sales transactions prior to the delivery period, and some of the actual transactions were entered into during the period of high forward prices during the middle of 2008. Because prices have declined since July 2008, the overall impact of the actual transactions is an increase in the pro forma expense. The table below shows the impact of the actual transactions in the pro forma. Overall, the actual transactions increase pro forma expense by $4,314,400 on a system basis, $1,527,729 Idaho allocation, compared to what expenses would be based solely on the AURORA model output. Avista's hedging strategy and risk management program are explained in Mr. Storro's testimony.

Actual Electric and Natural Gas Transactions
Impact on Proforma Power Supply Expense
Term Transactions through 11-30-08

	System Numbers	Idaho Allocation
Physical Electric Transactions Mark to Market	$43,304	$15,334
Financial Electric Transactions Mark to Market	$2,923,297	$1,035,139
Natural Gas Transactions Mark to Market	$1,347,800	$477,256
Total Proforma Impact of Actual Transactions	$4,314,400	$1,527,729

Detailed workpapers are provided for all the actual transactions included in the pro forma.

Q. Are there any other changes in how the pro forma in this case was developed?

A. No. Other than including actual transactions and the removal of the hydro rate mitigation adjustment, the process to develop the pro forma net power supply expense in this case is the same as in the 2008 general rate case.

A brief description of each adjustment is provided in Exhibit No. 6, Schedule 2. Detailed workpapers have been provided to the Commission coincident to this filing to support each of the pro forma revenues and expenses. The detailed workpapers for each adjustment show the actual revenue or expense in the test period, and the pro forma revenue or expense.

Long-Term Contracts

Q. How are long-term power contracts included in the pro forma?

A. Long-term power contracts are included in the pro forma by including the energy receipt or obligation associated with the contract in the AURORA model and including the cost or revenue in the pro forma net power supply expense.

Q. Are there any new power purchases or sales in the pro forma?

A. Yes. The Company entered into a two-year agreement to purchase generation from the Wells hydroelectric plant that is assigned to the Colville Indian Tribe, which I describe in more detail below. Also, the purchase from Thompson River Cogen, a cogeneration plant in Thompson Falls, Montana, that was included in the 2008 rate case, was removed from this case because of the delays in the start-up of the plant.

Q. Please describe the purchase of the Colville Indian Tribe's Well's generation output?

A. Avista entered into a two-year agreement beginning October 2008 and ending September 2010 to purchase the Colville Indian Tribe's 4.5% share of the output of the Wells hydroelectric generation. Prior to this agreement, Avista purchased 3.34% of the Well's output at actual production cost from the owner of Wells, Douglas PUD. The additional 4.5% of Wells output assigned to the Colville Indian Tribe was purchased through a competitive auction at the market prices at the time. The purchase of the Colville Indian Tribe's share of Wells output at market prices is the reason for the increase in Well's cost in the pro forma.

Q. Why is this purchase important to the Company?

A. This purchase was important because of the capacity and ancillary products that come with a Mid Columbia generation product. In addition to the energy, Mid Columbia generation has dynamic capacity that the Company uses for frequency regulation and load following. The generation also comes with a "paper pond" that allows the Company to shift generation from low load to high load hours.

The amount of generation the Company has at the Mid Columbia is being reduced as the existing contracts with Grant PUD expire and the amount of generation at Priest Rapids (November 2005) and Wanapum (November 2009) are reduced by roughly half. The Wells purchase makes up for a good portion of the loss of capacity at Priest Rapids and

Wanapum, and allows the Company to maintain regulation functions at the Mid Columbia.

Short-Term Power Purchases and Sales

Q. How are short-term transactions included in the pro forma?

A. After including the actual short-term transactions explained earlier as resources and obligations in the AURORA model, the balance of the short-term electric power purchases and sales are an output of the AURORA model. The model calculates both the volumes and price of short-term purchases and sales that balance the system's generation and long-term purchases with retail load and long-term obligations. The price of the short-term transactions represents the price of spot market power as determined by the AURORA model.

Thermal Fuel Expense

Q. How are thermal fuel expenses determined in the pro forma?

A. Thermal fuel expenses include Colstrip coal costs, Kettle Falls wood waste costs and natural gas expense for the Company's gas-fired resources including Coyote Springs 2, Rathdrum, Northeast, Boulder Park, and the Kettle Falls combustion turbine. Unit coal costs at Colstrip are based on the long-term coal supply and transportation agreements. Unit wood fuel costs at Kettle

Falls are based on multiple shorter-term contracts with fuel suppliers and inventory. Total fuel costs for each plant are based on the unit fuel cost and the plant's level of generation as determined by the AURORA model. Exhibit No. 6, Schedule 3 shows the pro forma fuel costs by month for each plant. Mr. Kalich provides details and supporting workpapers regarding the fuel costs for the Company's thermal plants.

Transmission Expense

Q. What changes in transmission expense are in the pro forma compared to the test year or the 2008 rate case?

A. There is almost no change in transmission expense. Transmission expense in the pro forma is $4,000 (system) higher than the test year actual expense and $169,000 lower than the pro forma in the 2008 rate case.

Q. Will there be additional transmission expense in the pro form period that has not been included in this case?

A. Yes, beginning January 1, 2010 the Company will purchase 250 MW of BPA point-to-point transmission for the Lancaster plant. The cost of this transmission will be approximately $375,250 per month. The Company proposes to track this expense in the PCA at 100 percent until such time that this expense is included in base retail rates.

IV. PCA CALCULATIONS

Proposed Changes to the PCA

Q. Is the Company proposing any changes to the PCA methodology?

A. Yes. The Company is proposing four changes to the PCA calculations. The first is to change the sharing percentages between Customers and the Company from 90%/10% to 95%/5%. The second change is to include third-party transmission expense (Accounts 565710 & 565000) and transmission revenue (Accounts 456100, 456016 & 456700) in the PCA. The third change is to use the average cost of production/transmission included in base rates as the retail revenue credit instead of the marginal cost of power currently used in the PCA. The fourth change is to include the Production Tax Credit in the PCA.

The Company is also proposing to include the expenses and revenues related to the Lancaster plant in the PCA beginning January 1, 2010, until the expense and revenue related to the Lancaster plant are included in base rates.

Customer/Company Sharing

Q. Why is the Company proposing a change in the sharing between customers and the Company in the PCA?

A. The primary reason to change the sharing methodology is the increased volatility of power supply costs. The increased volatility is driven primarily by two factors. One is the overall level of prices. Higher prices mean greater absolute variability due to hydro generation and load variations. Also important is the recent price volatility in the energy markets. For example, actual prices varied from $88/MWh in April 2008 when the Company was purchasing energy due to low hydro generation from the delayed run-off to $25/MWh in June when the hydro run-off materialized and the Company was selling surplus power. This kind of price volatility coupled with hydro variation can cause very large changes in the Company's power supply expense. In April 2008 alone, the Company's power supply expense exceeded the authorized level by over $4.0 million (Idaho Allocation, over $14 million on a system basis), leading to a PCA deferral of over $3.5 million, with the Company absorbing over $400,000.

An additional volatility the Company faces is the price of natural gas. This is a significant source of volatility with Coyote Springs 2 and will become even more significant with the addition of Lancaster in 2010. A rough rule of thumb is that every $1/dth change in natural gas prices changes Avista's system power supply expense by $10 million without the Lancaster plant. Natural gas prices have varied by over $5/dth during 2008. This variability caused by natural gas price will be even greater when the Company begins receiving power from the Lancaster plant in 2010.

<u>Transmission Expense and Revenue</u>

Q. Why is the Company proposing to include transmission expense and revenues in the PCA?

A. Transmission expense is a significant component of the Company's overall power supply expense. While much of the transmission is purchased under long-term contracts, some is purchased on a short-term basis and is subject to variability in the expense level. Including transmission expense in the PCA tracks the variability in this power supply related expense.

Including transmission revenue in the PCA is a fairness issue. If customers are absorbing the majority of any increases in transmission expense then it is fair that they receive the majority of increases in transmission revenue. The transmission revenue the Company is proposing to include in the PCA is the sale of Avista transmission to third parties.

Including transmission revenues and expenses in the PCA is also consistent with the Company's Retail Revenue Credit proposal. The proposed Retail Revenue Credit includes both the Production and Transmission components of the retail rate.

Finally, including transmission expense in the PCA is necessary in order for the Company to include the expenses associated with the Lancaster plant in the PCA. As stated earlier in my testimony, beginning January 1, 2010, Avista will be assigned 250 MW of BPA point-to-point transmission from the Lancaster plant. This transmission is the only means to move the power from the Lancaster plant to Avista's system. The annual cost of this transmission is approximately $4.5 million or $375,250 per month. Transmission expense must be included in the PCA in order for the Company to recover all the costs associated with the Lancaster plant. If the PCA is not modified to reflect transmission expense in the PCA, then the Company proposes that only the transmission expense for the Lancaster plant be included in the PCA (at 100% of expense) until the costs are included in base retail rates.

Retail Revenue Credit

Q. What change is the Company proposing to the Retail Revenue Credit rate?

A. The Company proposes that the average cost of production and transmission be used as the retail revenue credit rate in the PCA. Currently, the retail revenue credit rate is the marginal cost of power. The average production and transmission cost represents the power commodity component of retail rates and is the revenue collected from customers to recover power and transmission costs. Using the average cost of production and transmission as the retail revenue credit in the PCA ensures that the actual revenue collected from customers when retail sales increase is credited back against the increased power supply expense and only the difference between the actual cost of power and the amount of revenue collected from customers is included in the PCA.

The average production cost also works equally well when actual sales are lower than authorized sales. In that case, actual power supply expense is lower because loads are lower. The retail revenue credit adjusts for the actual revenue the Company did not receive from customers.

The benefit of using the average cost of production and transmission versus the marginal cost of power is that the average cost of production works equitably for customers and the Company when sales are both higher and lower than the authorized level. As a note, the average cost of production was used in the PCA for the months of October 2008 through December 2008. Beginning January 2009, the retail revenue credit returned to being the marginal cost of power.

Inclusion of Production Tax Credit in the PCA

Q. Please explain the Production Tax Credit and how the Company proposes to include it in the PCA.

A. The Production Tax Credit (PTC) is a Federal income tax credit the Company receives based on energy production at the Kettle Falls bio-fuel plant and for increased generation from upgrades at Cabinet Gorge dam. The amount of PTC included in this case is a system amount of $2,766,722, which lowers customer's rates. The PTC for ratemaking purposes is grossed up to a revenue level of $4.26 million (system) using the conversion rate of 65%, which is one minus the federal income tax rate. The PTC is set to expire for Kettle Falls on December 31, 2009.

Q. Why is it appropriate to include the PTC in the PCA?

A. The PTC is a credit that is directly tied to the level of generation at Kettle Falls and Cabinet Gorge. The credit is accrued monthly based on the level of generation at Kettle Falls and Cabinet Gorge. It is very similar to other power supply expenses, such as fuel expense, which is directly related to the level of production, and included in the PCA. Because it is directly tied to the level of generation at Kettle Falls and Cabinet Gorge it is an appropriate revenue item to include in the PCA.

As noted earlier, the Kettle Falls portion of the PTC is set to expire on December 31, 2009. When the PTC expires at the end of 2009, the PCA will properly account for this change. By including the PTC in the PCA, customers will appropriately receive the full benefits from the PTC through December 2009. If the PTC is not tracked through the PCA, beginning January 2010 Avista would inappropriately continue to flow a tax benefit to customers that does not exist.

The Company proposes that Idaho's share of the system PTC amount of $4.26 million be included in the authorized level of power supply expense in the PCA, which would then be compared with the actual PTC credit each month in the actual power supply expense in the PCA. The differences between the actual PTC and the authorized PTC will flow through the PCA in the same manner as other power supply expenses and revenues.

<u>Inclusion of Lancaster Expense and Revenue in the PCA</u>

Q. How does the Company propose including the expense and revenue related to the Lancaster plant in the PCA

A. Avista Utilities will begin purchasing the output of the Lancaster plant January 1, 2010. The Company proposes that the expense and revenues related to the Lancaster plant be included in the PCA until they are reflected in base retail rates.

The Lancaster plant has several cost components. Three cost components are part of the Lancaster power purchase agreement and include a fixed capital payment, a fixed O&M payment and a variable O&M payment. All three of these expenses will be recorded in Account 555, Purchased Power Expense, which is an account tracked by the PCA. The capital payment and the fixed O&M payment will be relatively constant month to month, and the variable O&M expense will be dependent on the amount of generation at the plant.

Other Lancaster plant costs include natural gas fuel expense and the natural gas pipeline transportation expense, both of which are included in Account 547, Fuel Expense, and the BPA transmission that is recorded in Account 565, Transmission Expense. As explained earlier, the Company is proposing in this filing that Transmission Expense and Transmission Revenue be included in the PCA calculation.

The Company is proposing that the fixed expenses related to the Lancaster plant be isolated and tracked in the PCA at 100% of the actual expense. The fixed expenses include the capacity payment (capital payment and fixed O&M payment), the natural gas pipeline transportation payment and the BPA transmission payment. These fixed payments do not vary and would otherwise be 100% included in base rates.

The Company proposes that the variable expenses and revenue from the Lancaster plant be included in the PCA in a manner similar to other expenses and revenues that would be subject to the Company's proposed 95%/5% Customer/Company PCA sharing. The variable expenses related to the Lancaster plant include the variable O&M payment, natural gas fuel expense and the net impact of either reduced electricity purchases or increased electricity sales. Tracking the variable expense and revenue in the PCA at the proposed 95%/5% sharing arrangement is similar to how these expenses are tracked for other resources.

New Authorized Power Supply and Transmission Expense

Q. What is the authorized power supply expense and revenue proposed by the Company for the PCA?

A. The proposed authorized level of annual system power supply expense is $192,927,906. This is the sum of Accounts 555 (Purchased Power), 501 (Thermal Fuel), 547 (Fuel), less Account 447 (Sale for Resale). The proposed level of Transmission Expense is $14,168,901. The proposed level of Transmission Revenue is $9,478,694.

The level of retail sales MWh and the retail revenue credit will also be updated. The proposed authorized level of retail sales to be used in the PCA is the July 2009 through June 2010 pro forma retail sales. The proposed retail revenue credit is $47.85/MWh, which is the average cost of production/transmission in this filing.

The proposed authorized PCA expense and revenue is shown in Exhibit 6, Schedule 4.

Q. Does that conclude your pre-filed direct testimony?

A. Yes.

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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 NO. AVU-E-09-01 EXHIBIT NO. 6 WILLIAM G. JOHNSON

FOR AVISTA CORPORATION

(ELECTRIC ONLY)

Avista Corp.
Power Supply Pro forma - Idaho Jurisdiction
System Numbers - Oct 2007 - Sep 2008 Actual and Jul 09 - Jun 10 Pro forma

Line No.		Oct 07 - Sep 08 Actuals	Adjustment	Jul 09 - Jun 10 Pro forma
	555 PURCHASED POWER			
1	Modeled Short-Term Market Purchases	$0	$51,202	$51,202
2	Actual ST Market Purchases - Physical	148,407	-117,609	30,798
3	Actual ST Purchases - Financial M-to-M	$0	$2,923	2,923
4	Rocky Reach	2,068	89	2,157
5	Wanapum	5,406	-3,369	2,037
6	Wells, Avista and Colville Share	1,311	11,302	12,613
7	Priest Rapids Project	4,858	2,361	7,219
8	Grant Displacement	5,552	-219	5,333
9	Douglas Settlement	497	122	619
10	WNP-3	12,553	2,248	14,801
11	Deer Lake-IP&L	7	0	7
12	Small Power	1,125	29	1,154
13	Stimson	1,964	138	2,102
14	Spokane-Upriver	1,790	300	2,090
15	Douglas Exchange Capacity	1,648	-1,648	0
16	Seattle Exchange Capacity	1,699	-1,699	0
17	Black Creek Index Purchase	144	11	155
18	Non-Monetary	-242	242	0
19	Contract A	6,808	-19	6,789
20	Contract B	6,764	-19	6,745
21	Contract C	6,675	-17	6,658
22	Contract D	7,576	-20	7,556
23	CS2 Exchange	387	-387	0
24	Northwestern Deviation Energy	1,867	-1,867	0
25	BPA NT Deviation Energy	3,236	-3,236	0
26	Potlatch Co-Gen Purchase	18,439	-18,439	0
27	Spinning Reserve Purchase	1,500	0	1,500
28	Ancillary Services	670	-670	0
29	Stateline Wind Purchase	3,424	-159	3,265
30	Total Account 555	246,133	-78,409	167,724
	557 OTHER EXPENSES			
31	Broker Commission Fees	104	0	104
32	REC Purchases	364	-14	350
33	Bad Debt Reserve	2,728	-2,728	0
34	Natural Gas Fuel Purchases	39,075	-39,075	0
35	Total Account 557	42,271	-41,817	454
	501 THERMAL FUEL EXPENSE			
36	Kettle Falls - Wood Fuel	7,227	3,848	11,075
37	Kettle Falls - Start-up Gas	23	0	23
38	Colstrip - Coal	17,688	418	18,106
39	Colstip - Oil	91	111	202
40	Total Account 501	25,029	4,377	29,406
	547 OTHER FUEL EXPENSE			
41	Coyote Springs Gas	99,105	-30,692	68,413
42	Actual Gas Purchases Financial M-to-M	0	1,348	1,348
43	Gas Transportation Charge	5,961	911	6,872
44	Rathdrum Gas	616	-342	274
45	Northeast CT Gas	277	-216	61
46	Boulder Park Gas	2,127	-2,090	37
47	Kettle Falls CT Gas	312	-236	76
48	Total Account 547	108,398	-31,316	77,082
	565 TRANSMISSION OF ELECTRICITY BY OTHERS			
49	WNP-3	789	0	789
50	Sand Dunes-Warden	20	0	20
51	Black Creek Wheeling	18	2	20
52	Wheeling for System Sales & Purchases	845	0	845
53	PTP for Colstrip & Coyote	8,427	3	8,430
54	BPA Townsend-Garrison Wheeling	1,173	0	1,173
55	Avista on BPA - Borderline	1,483	-5	1,478
56	Kootenai for Worley	39	6	45
57	Sagle-Northern Lights	136	-2	134
58	Garrison-Burke	592	0	592

Avista Corp.
Power Supply Pro forma - Idaho Jurisdiction
System Numbers - Oct 2007 - Sep 2008 Actual and Jul 09 - Jun 10 Pro forma

Line No.		Oct 07 - Sep 08 Actuals	Adjustment	Jul 09 - Jun 10 Pro forma
59	PGE Firm Wheeling	643	0	643
60	Total Account 565	14,165	4	14,169
	536 WATER FOR POWER			
61	Headwater Benefits Payments	654	1	655
	549 MISC OTHER GENERATION EXPENSE			
62	Rathdrum Municipal Payment	175	-15	160
63	TOTAL EXPENSE	436,825	-147,175	289,650
	447 SALES FOR RESALE			
64	Modeled Short-Term Market Sales	0	53,641	53,641
65	Actual ST Market Sales - Physical	132,119	-119,617	12,502
66	Peaker (PGE) Capacity Sale	1,800	0	1,800
67	Nichols Pumping Sale	3,440	402	3,842
68	Sovereign/Kaiser DES	816	-755	61
69	Pend Oreille DES & Spinning	555	-165	390
70	Northwestern Load Following	5,225	-1,968	3,257
71	SMUD Sale	49,173	-43,331	5,842
72	Ancillary Services	670	-670	0
73	Spokane Energy Service Fee - Peaker Sale	-52	0	-52
74	BPA NT Deviation Energy	2,073	-2,073	0
75	Total Account 447	195,819	-114,536	81,283
	456 OTHER ELECTRIC REVENUE			
76	Renewable Energy Credit Sales	13	-13	0
77	Gas Not Consumed Sales Revenue	41,799	-41,799	0
78	Total Account 456	41,812	-41,812	0
	453 SALES OF WATER AND WATER POWER			
79	Upstream Storage Revenue	303	-1	302
	454 MISC RENTS			
80	Colstrip Rents	57	-33	24
81	TOTAL REVENUE	237,991	-156,382	81,609
82	TOTAL NET EXPENSE	198,834	9,206	208,040
83	**Potlatch Purchase Assigned to Idaho**		18,439	
84	**Total Adjustment Including Potlatch**		27,645	

Exhibit No. 6
Case No. AVU-E-09-01
W. Johnson, Avista
Schedule 1, p. 2 of 2

Avista Corp.
Brief Description of Power Supply Adjustments

Line No.

1 **Short-term Market Purchases** - Short-term purchases from the AURORA Dispatch Simulation Model.

2 **Actual ST Market Purchases Physical** – Expense of the actual term transactions entered into for the pro forma period as of 11-30-08.

3 **Actual ST Purchases – Financial M-to-M** – Mark to model price expense of actual financial (fixed for floating swaps) electricity purchases entered into for the pro forma period as of 11-30-08.

4 **Rocky Reach** - The proforma cost for Rocky Reach is based on Chelan PUD's budgeted expenses. Avista's costs are based on the Company's 2.9% share of total cost.

5 **Wanapum** - Proforma costs are based on Grant County PUD's Power Cost Forecast for Wanapum. Avista's costs are based on the Company's 8.2% share of total Wanapum costs for July 2009 through October 2009. The Wanapum contract expires October 31, 2009. Beginning November 2009 Wanapum becomes part of the Priest Rapids Project and Wanapum costs are included in the Priest Rapids Project costs for November 2009 through June 2010.

6 **Wells** - Wells' costs are based on the Company's 3.34% share of total cost at project costs plus 4.5% of Well's output purchased from the Colville Indian Tribe at a competitive auction rate.

7 **Priest Rapids Project** - Priest Rapids Project expense includes the expense related to the purchased power from the Priest Rapids development for the entire pro forma year and power from the Wanapum development for the months of November 2009 through June 2010.

8 **Grant Displacement** - Grant Displacement is scheduled energy from Grant PUD that is priced at Grant's cost.

9 **Douglas Settlement** – Douglas Settlement is for power Avista purchases from Douglas PUD per the 1989 Settlement Agreement.

Exhibit No.6
Case No. AVU-E-09-01
W. Johnson, Avista
Schedule 2, p. 1 of 8

10 **WNP-3 -** Pro forma costs are based on the amount of energy and the lesser of the actual rate or the midpoint. The pro forma uses the actual rate for contract year 2008 through 2009 escalated at the 5-year average escalation rate to the pro forma period.

11 **Deer Lake-IP&L** - Proforma expense is for power purchased from Inland Power to serve Avista customers.

12 **Small Power** - Proforma costs are based on an expected generation and proforma period contract rates. (Contract details are provided in a CONFIDENTIAL workpaper).

13 **Stimson** – This purchase is from the cogeneration plant at Plummer, Idaho. Pro forma costs are based on expected generation and proforma period contract rates.

14 **Spokane-Upriver** - Proforma expense is based on a purchase on the net of pumping (at the plant) generation at a rate equal to the 8 year levelized avoided cost included in the Company's 2003 Integrated Resource Plan.

15 **Douglas Exchange Capacity** – Proforma is $0 because Avista bids annually for this capacity.

16 **Seattle Exchange Capacity** – Proforma is $0 because contract terminates March 31, 2009.

17 **Black Creek Index Purchase** - Expense is for an October purchase at index prices less transmission expense and a margin.

18 **Non-Monetary** - Expense is normalized to $0 in the proforma.

19 **Contract A** - This is a power purchase for the period January 2007 through December 2010 (Contract details are provided in a CONFIDENTIAL workpaper).

20 **Contract B** - This is a power purchase for the period January 2007 through December 2010 (Contract details are provided in a CONFIDENTIAL workpaper).

21 **Contract C** - This is a power purchase for the period January 2007 through December 2010 (Contract details are provided in a CONFIDENTIAL workpaper).

22 **Contract D** - This is a power purchase for the period January 2007 through December 2010 (Contract details are provided in a CONFIDENTIAL workpaper).

23 **CS2 Exchange** – Proforma is $0 because contract terminated Dec. 31, 2007.

24 **NorthWestern Load Following Deviation Energy** – Proforma expense is $0 because deviation energy is priced at market and is not included In AURORA model.

25 **BPA NT Deviation Energy** – Proforma expense is $0 because deviation energy is priced at market and is not included In AURORA model.

26 **Potlatch Co-Gen Purchase** - Pro forma expense is $0 because Potlatch purchase expense is directly assigned to the Idaho jurisdiction and is not included in system power supply expense.

27 **Spinning Reserve Purchase**– Pro forma expense is for a purchase of spinning reserves during the months of May and June that matches the test year purchase expense.

28 **Ancillary Services** - Proforma expense is $0 because this is an intra-utility expense (matching revenue in Account 447).

29 **Stateline Wind Purchase** - Proforma expense is for a 10-year purchase from a Northwest wind project. Expense is based on expected energy amount times the contract rate. (Contract details are provided in a CONFIDENTIAL workpaper).

30 **Total Account 555**

31 **Broker Commission Fees** – Proforma expense is associated with purchases and sales of electricity and natural gas fuel.

32 **REC Purchases** – Expense is for the purchase of California certifiable renewable Energy Credits to support the SMUD Sale.

33 **Bad Debt Reserve** – Expense was for power the Company delivered but no revenue was received (Lehman bankruptcy). Pro forma expense is $0.

34 **Natural Gas Fuel Purchases** – This is the expense for natural gas purchased for but not consumed for generation. Proforma expense is $0 because all gas purchased is assumed to be used for generation, and included in Account 547.

35 **Total Account 557**

36 **Kettle Falls Wood Fuel Cost** - Proforma fuel expense is based on the generation of the Kettle Falls plant in the AURORA Model and the projected unit cost of fuel.

37 **Kettle Falls-Start-up Gas** – Pro forma expense is for start-up gas at Kettle Falls and is based on the test-year expense.

38 **Colstrip Coal Cost** - Proforma fuel expense is based on the generation of the Colstrip plant in the AURORA Model and the projected unit cost of fuel.

39 **Colstrip Oil** – Pro forma expense is for start-up oil expense. Pro forma is based on a five year average.

40 **Total Account 501**

41 **Coyote Springs Gas** - Proforma expense is an output of the AURORA Model based on the projected unit cost of fuel and the dispatch of the plant, which determines the volume of fuel consumed.

42 **Actual Gas Purchases Financial M-to-M** - Mark to model price expense of actual natural gas purchases entered into for the pro forma period as of 11-30-08.

43 **Gas Transportation Charge** – This expense is for transportation of natural gas from AECO to the Coyote Springs 2 plant. Proforma expense is based on transportation charges in Canada and from the Canadian Border (Kingsgate) and for the Coyote Springs lateral.

44 **Rathdrum Gas** - Proforma expense is an output of the AURORA Model based on the projected unit cost of fuel and the dispatch of the plant, which determines the volume of fuel consumed.

45 **Northeast CT Gas** – Proforma expense is an output of the AURORA Model based on the projected unit cost of fuel and the dispatch of the plant (including test firing), which determines the volume of fuel consumed.

46 **Boulder Park Gas** – Proforma expense is an output of the AURORA Model based on the projected unit cost of fuel and the dispatch of the plant, which determines the volume of fuel consumed.

47 **Kettle Falls CT Gas** – Proforma expense is an output of the AURORA Model based on the projected unit cost of fuel and the dispatch of the plant, which determines the volume of fuel consumed.

48 **Total Account 547**

49 **WNP-3 Transmission** - Proforma WNP-3 wheeling is based on 32.22 MW at a rate of $2.04/kW/mo.

50 **Sand Dunes-Warden** - Pro forma expense is for a transmission expense with Grant PUD.

51 **Black Creek Wheeling** – Expense is for wheeling and shaping associated with the Black Creek power purchase.

52 **Wheeling for System Sales and Purchases** – Proforma expense is short-term transmission purchases.

53 **PTP for Colstrip and Coyotes Springs 2**– This wheeling is for the transmission of 196 MW from Colstrip at the Garrison substation and 272 MW from the Coyote Springs 2 plant to Avista's system. Proforma expense is based on 468 MW of capacity at a rate of $1.501/kW/mo.

54 **BPA Townsend-Garrison Wheeling** – This expense is for the transmission of Colstrip power from the Townsend substation to the Garrison substation.

55 **Avista on BPA Borderline** – This expense is to serve Avista load off of BPA transmission. Proforma expense is based on Avista's borderline loads priced at BPA's NT transmission rates plus ancillary services cost and use of facilities charges.

56 **Kootenai for Worley** – This expense is for Avista load served using Kootenai PUD's facilities.

57 **Sagle-Northern Lights** – Expense is for transmission purchased from Northern Light Utility to serve Avista customers in northern Idaho.

58 **Garrison Burke** – Garrison Burke wheeling is an expense for the transmission of Colstrip energy above 196 MW from the Garrison substation over Northwestern Energy's transmission system to the interconnection of Northwestern Energy and Avista.

59 **PGE Firm Wheeling** – PGE Firm wheeling reflects the cost of transmission from the John Day substation to COB (Intertie South) purchased from Portland General Electric. The Proforma expense is based on 100 MW at the current rate of $.53549/kW/mo.

60 **Total Account 565**

61 **Headwater Benefits Expense** - Proforma expense is based on the expense for contract year September 2008 through August 2009

62 **Rathdrum Municipal Payment** – This includes a payment in Jan. 2010 of $160,000 to the city of Rathdrum for mitigation related to the Rathdrum generating facility.

63 **Total Expenses** – Sum of Accounts 555, 557, 501, 547, 565, 536, and 549.

64 **Modeled Short-Term Market Sales** - Short-term market sales from the AURORA Model simulation.

65 **Actual ST Market Sales-Physical** – Revenue from the actual term transactions entered into for the pro forma period as of 11-30-08

66 **Peaker (PGE) Capacity Sale** – This proforma revenue is based on 150 MW of capacity at a price of $1/kW/mo.

67 **Nichols Pumping Sale** – This is a sale of energy to other Colstrip Units 3 and 4 owners at the Mid Columbia index price. Proforma revenue is based on approximately 8 MW at the market price as determined by the AURORA model.

68 **Sovereign/Kaiser DES** – This contract provides load control services to Kaiser's Trentwood plant. (Contract details are provided in a CONFIDENTIAL workpaper).

69 **Pend Oreille DES & Spinning Reserves** – This contract provides load control and spinning reserves for Pend Oreille PUD. (Contract details are provided in a CONFIDENTIAL workpaper).

70 **Northwestern Load Following** – This contract provides load following capacity to Northwestern Energy. (Contract details are provided in a CONFIDENTIAL workpaper).

71 **SMUD Sale** – Proforma revenue is the expected margin (margin only, not including index priced energy) from the sale of energy and associated renewable energy credits.

72 **Ancillary Services** - Proforma revenue is $0 because it is intra-utility revenue (matching expense in Account 555).

73 **Spokane Energy Service Fee** – Peaker Sale – Expense is for the scheduling of the Peaker (Portland General) capacity sales.

74 **BPA NT Deviation Energy** – Proforma revenue is $0 because deviation energy is priced at index and is not included in the AURORA model.

75 **Total Account 447**

76 **Renewable energy Credit Sales** – Proforma revenue is $0 because test year revenue was for non-reoccurring renewable energy credit sales.

77 **Gas Not Consumed Sales Revenue** - This is the revenue for natural gas purchased for but not consumed for generation. Proforma expense is $0 because all gas purchased is assumed to be used for generation, and included in Account 547.

78 **Total Account 456**

79 **Upstream Storage Revenue** – Proforma revenue is based on the revenue for contract year September 2008 through August 2009.

80 **Colstrip Rents** – Proforma revenue is based on expected revenue.

81 **Total Revenue** – Sum of Accounts 447, 456, 453 and 454.

82 **Total Net Expense** – Total expense minus total revenue.

83 **Potlatch Purchase Assigned to Idaho** – This line shows the Potlatch purchase adjustment. The Potlatch expense is directly assigned to Idaho and is not included in the pro forma system power supply expense. The Potlatch purchase expense is included in the adjustment in line 83 to show the total adjustment from test year actual expense (includes Potlatch) to the proforma.

84 **Total Adjustment Including Potlatch** – This is the total adjustment in power supply expense factoring in the Potlatch purchase expense directly assigned to Idaho.

Avista Corp.
Market Purchases and Sales, Plant Generation and Fuel Cost Summary
Idaho Pro forma July 2009 - June 2010

		744	672	744	719	744	720	744	744	720	745	720	744
	Total	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09
Market Sales - Dollars	-$53,641,458	-$2,241,792	-$2,308,978	-$4,341,490	-$5,065,467	-$5,736,132	-$6,961,820	-$9,793,760	-$2,503,910	-$2,817,366	-$2,664,119	-$4,475,275	-$4,731,350
Market Sales - MWh	(1,241,847)	-36,866	-40,394	-81,660	-115,966	-196,354	-249,828	-198,727	-47,585	-60,318	-55,247	-85,205	-73,697
Average Market Sales Price -$/ MWh	$43.19	$60.81	$57.16	$53.17	$43.68	$29.21	$27.87	$49.28	$52.62	$46.71	$48.22	$52.52	$64.20
Market Purchases - Dollars	$51,202,237	$8,765,288	$5,689,822	$4,443,143	$2,639,681	$732,288	$581,719	$1,762,968	$6,521,264	$4,645,830	$5,563,051	$4,587,867	$5,269,317
Market Purchases - MWh	733,402	116,680	82,149	69,393	44,063	11,521	11,124	23,514	84,282	65,068	90,283	68,714	66,612
Average Market Purchase Price - $/MWh	$69.81	$75.12	$69.26	$64.03	$59.91	$63.56		$74.97	$77.37	$71.40	$61.62	$66.77	$79.11
Net Market Purchases (Sales) MWh	-508,445	79,815	41,755	-12,267	-71,903	-184,834	-238,704	-175,213	36,697	4,750	35,036	-16,491	-7,086
Net Market Purchases (Sales) aMW	-58.0	107	62	-16	-100	-248	-332	-236	49	7	47	-23	-10
Average Sale and Purchase Price - $/MWh	$53.08	$71.69	$65.27	$58.16	$48.15	$31.12	$28.91	$52.00	$68.44	$59.52	$56.53	$58.88	$71.28
Colstrip MWh	1,668,726	151,508	138,617	152,205	136,716	90,572	93,714	151,677	153,456	148,519	152,226	148,519	150,998
Colstrip Fuel Cost $/MWh	$10.85	$11.35	$11.35	$11.35	$11.35	$11.35	$11.35	$10.43	$10.43	$10.43	$10.43	$10.43	$10.43
Colstrip Fuel Cost	$18,106,171	$1,719,085	$1,572,826	$1,726,998	$1,551,254	$1,027,683	$1,063,326	$1,582,281	$1,600,843	$1,549,333	$1,588,007	$1,549,333	$1,575,202
Kettle Falls MWh	306,067	31,582	29,840	32,593	7,534	0	0	34,198	34,499	33,401	34,510	33,401	34,508
Kettle Falls Fuel Cost $/MWh	$36.18	$40.51	$40.40	$40.43	$40.45	#DIV/0!		$34.08	$34.06	$34.06	$34.06	$34.06	$34.06
Kettle Falls Fuel Cost	$11,074,827	$1,279,426	$1,205,540	$1,317,832	$304,715	$0	$0	$1,165,524	$1,175,192	$1,137,788	$1,175,547	$1,137,773	$1,175,490
Coyote Springs MWh	1,302,947	121,259	114,367	120,234	71,676	32,618	41,772	123,550	141,150	133,235	131,945	133,221	137,920
Coyote Springs Fuel Cost $/MWh	$52.51	$58.54	$58.07	$56.33	$50.62	$50.49	$51.84	$48.52	$48.92	$48.98	$49.13	$52.38	$54.91
Coyote Springs Fuel Cost	$68,413,368	$7,098,639	$6,641,601	$6,772,769	$3,628,055	$1,646,946	$2,165,475	$5,994,337	$6,904,777	$6,525,868	$6,482,726	$6,978,547	$7,573,628
Boulder Park MWh	537	0	5	0	1	68	6	226	222	0	0	7	0
Boulder Park Fuel Cost $/MWh	$68.97	$80.09	$79.74		$70.08	$69.44	$70.13	$67.41	$69.99	$69.18		$72.56	$75.48
Boulder Park Fuel Cost	$37,037	$26	$405	$0	$79	$4,746	$432	$15,247	$15,569	$34	$0	$488	$11
Kettle Falls CT MWh	1,122	31	70	11	55	199	52	355	309	18	1	15	5
Kettle Falls CT Fuel Cost $/MWh	$67.86	$77.65	$77.31	$75.02	$67.95	$67.33	$68.00	$65.39	$67.45	$66.51	$73.34	$70.36	$74.27
Kettle Falls CT Fuel Cost	$76,121	$2,440	$5,392	$821	$3,704	$13,367	$3,561	$23,233	$20,851	$1,170	$92	$1,081	$408
Rathdrum MWh	2,995	0	0	0	0	244	32	1,325	1,393	0	0	0	0
Rathdrum Fuel Cost $/MWh	$91.60					$92.90	$101.90	$90.00	$92.64	$37,214.45			
Rathdrum Fuel Cost	$274,309	$0	$0	$0	$0	$22,693	$3,239	$119,291	$129,061	$26	$0	$0	$0
Northeast MWh	409	0	0	0	0	2	2	178	228	0	0	0	0
Northeast Fuel Cost $/MWh	$149.84					$2,308.88	$390.35	$95.80	$128.05				
Northeast Fuel Cost	$61,285	$606	$5,006	$0	$1,168	$4,313	$684	$17,015	$29,166	$146	$672	$1,765	$744
Total Fuel Expense	$98,043,118	$10,100,222	$9,430,770	$9,818,420	$5,488,974	$2,719,747	$3,236,717	$8,916,928	$9,875,460	$9,214,365	$9,247,043	$9,668,988	$10,325,483

Net Fuel and Purchase Expense	$95,603,896

Exhibit No. 6
Case No. AVU-E-09-01
W. Johnson, Avista
Schedule 3, p. 1 of 1

Avista Corp
Pro forma July 2009 - June 2010
Idaho PCA Authorized Expense and Retail Sales

PCA Authorized Power Supply Expense (1)

	Total	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09
Account 555 - Purchased Power	167,723,928	17,892,299	13,948,277	11,702,418	9,845,833	7,139,382	6,910,121	14,145,639	18,310,220	16,118,990	15,627,434	17,464,201	18,619,113
Account 501 - Thermal Fuel	29,405,998	3,017,261	2,797,116	3,063,580	1,874,718	1,046,433	1,082,076	2,766,555	2,794,785	2,705,872	2,782,303	2,705,856	2,769,442
Account 547 - Natural Gas Fuel	77,081,920	7,674,378	7,225,071	7,346,257	4,205,672	2,264,731	2,746,057	7,195,939	8,126,241	7,539,410	7,056,157	7,554,549	8,147,458
Account 447 - Sale for Resale	81,283,939	3,572,539	3,575,843	5,615,647	6,284,541	6,904,594	8,097,153	14,555,753	7,300,966	7,463,249	4,680,365	6,420,266	6,813,022
Power Supply Expense	192,927,906	25,011,398	20,394,621	16,496,608	9,641,682	3,545,952	2,641,103	9,552,381	21,930,281	18,901,023	20,785,529	21,304,339	22,722,990
Transmission Expense	14,168,901	1,177,417	1,177,417	1,177,417	1,177,417	1,177,417	1,177,417	1,177,417	1,197,674	1,177,417	1,197,061	1,177,417	1,177,417
Transmission Revenue	9,478,694	691,030	637,319	710,607	695,003	811,018	1,144,180	1,060,504	894,674	729,456	749,649	712,323	642,930
Production Tax Credit (2)	-4,256,492	-437,445	-413,717	-451,217	-109,875	-7,253	-7,253	-473,072	-477,166	-462,222	-477,316	-462,215	-477,742

PCA Authorized Idaho Retail Sales and Potlatch Generation

	Total	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09
Total Retail Sales, MWh	3,206,010	301,203	281,272	271,576	259,299	256,228	238,147	264,695	263,718	242,515	259,188	268,154	300,014
Potlatch Generation, MWh	429,616	39,699	35,305	37,463	31,674	34,306	33,091	34,505	36,761	27,148	35,755	42,576	41,333

1) Expenses related to the Lancaster plant are not included in Authorized Power Supply Expense. The Company has proposed that the actual Lancaster fixed costs be included in the PCA at 100% and the actual Lancaster variable expenses and revenues be included at the Company's proposed 95/5% Customer/Company PCA sharing.

2) This level of Production Tax Credit (PTC), grossed up to a revenue level of 65%, is included in base retail rates. The actual PTC will be included in actual expense each month in the PCA.