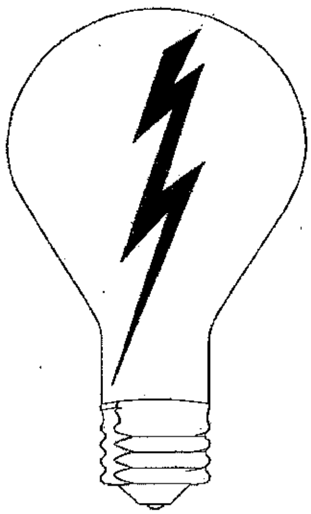
YEAR ENDING 12/31/2009

ANNUAL REPORT
OF

AVISTA CORPORATION

ELECTRIC UTILITY



TO THE
PUBLIC SERVICE COMMISSION
STATE OF MONTANA
1701 PROSPECT AVENUE
P.O. BOX 202601
HELENA, MT 59620-2601

REVISED - 2005

IDENTIFICATION

Year: **2009**

1.	Legal Name of Respondent:	Avista Corporation
2.	Name Under Which Respondent Does Business:	Avista Corp. and Avista Utilities
3.	Date Utility Service First Offered in Montana	July, 1960
4.	Address to send Correspondence Concerning Report:	1411 East Mission Avenue PO Box 3727 Spokane, WA 99220
5.	Person Responsible for This Report:	Christy Burmeister-Smith Vice President, Controller and Principal Accounting Officer
5a.	Telephone Number:	509-495-4256

Control Over Respondent

1. If direct control over the respondent was held by another entity at the end of year provide the following:
   1a. Name and address of the controlling organization or person:

   1b. Means by which control was held:

   1c. Percent Ownership:

SCHEDULE 2

Board of Directors

Line No.	Name of Director and Address (City, State) (a)		Remuneration (b)
1	Erik J. Anderson	3720 Carillon Point, Kirkland, WA 98033	$119,000.00
2	Kristianne Blake	P. O. Box 28338, Spokane, WA 99208	$133,540.00
3	Brian W. Dunham	5721 E Columbia Way, Ste 200 Vancouver WA 98661	$90,000.00
4	Roy Lewis Eiguren	712 Warm Springs Ave, Boise, ID 83712	$105,500.00
5	Jack W. Gustavel	P.O. Box J, Coeur d'Alene, ID 83816	$100,500.00
6	John F. Kelly	142 Isla Dorada Blvd. Coral Gables, FL 33143	$137,000.00
7	Michael L. Noel	11960 Six Shooter Rd., Prescott, AZ 86305	$108,000.00
8	Marc F. Racicot (1)	28013 Swan Cove Dr. Bigfork, MT 59911	$44,500.00
9	Heidi B. Stanley	PO Box 8650, Spokane, WA 99203	$106,500.00
10	R. John Taylor	P. O. Box 538, Lewiston, ID 83501	$111,452.00
11	Scott L. Morris (2)	1411 E. Mission Ave., Spokane, WA 99202	(2)
12			
13	(1) Mr. Racicot was elected as a director effective August 1, 2009.		
14	(2) Mr. Morris is the Chairman of the Board, President and Chief Executive Officer of Avista Corp.		
15			
16			
17			
18			
19			
20			

Officers

Year: 2009

Line No.	Title of Officer (a)	Department Supervised (b)	Name (c)
1			
2	Chairman of the Board, President		
3	& Chief Executive Officer	All	Scott L. Morris
4			
5	Senior Vice President, Chief Financial	Finance	Mark T. Thies
6	Officer		
7			
8	Senior Vice President, General Counsel	Legal	Marian M. Durkin
9	and Chief Compliance Officer		
10			
11	Senior Vice President and President of	Utility Operations	Dennis P. Vermillion
12	Avista Utilities		
13			
14	Senior Vice President of Human	Human Resources	Karen S. Feltes
15	Resources & Corporate Sercretary		
16			
17	Vice President, Controller and	Accounting	Christy M. Burmeister-Smith
18	Principal Accounting Officer		
19			
20	Vice President of State &	Regulatory	Kelly O. Norwood
21	Federal Regulation		
22			
23	Vice President of Transmission and	Transmission and	Don F. Kopczynski
24	Distribution Operations	Distribution	
25			
26	Vice President, Sustainable	Utility Operations	Roger D. Woodworth
27	Energy Solutions		
28			
29			
30	Vice President and Chief Counsel for	Legal/Regulatory	David J. Meyer
31	Regulatory and Governmental Affairs		
32			
33	Vice President of Finance	Finance	Jason R. Thackston
34			
35	Vice President and Chief Information	Information	James M. Kensok
36	Officer	Technology	
37			
38	Vice President of Energy Resources	Resource	Richard L. Storro
39		Management	
40			
41			
42			
43			
44			
45			
46			
47			
48			
49			
50			

Company Name: Avista Corporation **SCHEDULE 4**

CORPORATE STRUCTURE

Year: 2009

	Subsidiary/Company Name	Line of Business	Earnings	Percent of Total
1				
2	Avista Capital, Inc.	Parent company to the	$827,452	100.00%
3		Company's subsidiaries.		
4				
5	Avista Capital II	Business trusts formed for the purpose		
6		of issuing preferred trust securities.		
7				
8	Advantage IQ, Inc.	Provider of utility bill processing, payment and information		
9		services to multi-site customers in North America.		
10				
11	Avista Energy, Inc.	Wholesale electricity and natural gas trading, marketing and		
12		resource management. Majority of opertions sold 6/30/2007		
13				
14	Avista Power, LLC	Inactive.		
15				
16	Avista Turbine Power, Inc.	Receives assignments of purchase power agreements.		
17				
18	Steam Plant Square LLC	Commercial office and retail leasing.		
19	Courtyard Office Center	Commercial office and retail leasing.		
20				
21	Avista Ventures, Inc.	Inactive.		
22				
23	Avista Development, Inc.	Non-operating company which maintains an investment portfolio		
24		of real estate and other investments.		
25				
26	Pentzer Corporation	Parent of Bay Area Manufacturing and Pentzer Venture Holdings.		
27				
28	Bay Area Manufacturing	Holding Company. Parent of Advanced Manufacturing and		
29		Development, Inc.		
30				
31	Pentzer Venture Holdings	Inactive.		
32				
33	Advanced Manufacturing	Performs custom sheet metal manufacturing of electronic		
34	and Devlopment, Inc.	enclosures. Has a wood products division.		
35				
36	Avista Receivables Corp.	Acquires and sells accounts receivable		
37		of Avista Corp.		
38				
39	Spokane Energy, LLC	Marketing of energy.		
40				
41	Ecos IQ, Inc.	Formed in 2009 to acquire Ecos Consulting, Inc.		
42				
43	Avista Northwest Resources, LLC	Formed in 2009 to own an interest in a venture fund investment.		
44				
45				
46				
47				
48				
49				
50	**TOTAL**		827,452	

Company Name: Avista Corporation

SCHEDULE 5

CORPORATE ALLOCATIONS

Year: 2009

	Items Allocated	Classification	Allocation Method	$ to MT Utility	MT %	$ to Other
1						
2						
3						
4	Not applicable					
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34	**TOTAL**					

Company Name: Avista Corporation

SCHEDULE 6

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY

Year: 2009

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Utility	(e) % Total Affil. Revs.	(f) Charges to MT Utility
1						
2	None					
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32	**TOTAL**					

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2009

Line No.	(a) Affiliate Name	(b) Products & Services	(c) Method to Determine Price	(d) Charges to Affiliate	(e) % Total Affil. Exp.	(f) Revenues to MT Utility
1						
2						
3	Not applicable					
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32	**TOTAL**					

MONTANA UTILITY INCOME STATEMENT

Year: 2009

	Account Number & Title	Last Year	This Year	% Change
1	400 Operating Revenues	18,707,793	33,312	-99.82%
2				
3	Operating Expenses			
4	401 Operation Expenses	25,676,666	19,875,585	-22.59%
5	402 Maintenance Expense	6,955,495	9,583,489	37.78%
6	403 Depreciation Expense	11,890,163	12,339,526	3.78%
7	404-405 Amortization of Electric Plant	none/n.a.	none/n.a.	#VALUE!
8	406 Amort. of Plant Acquisition Adjustments	none/n.a.	none/n.a.	#VALUE!
9	407 Amort. of Property Losses, Unrecovered Plant			
10	& Regulatory Study Costs	none/n.a.	none/n.a.	#VALUE!
11	408.1 Taxes Other Than Income Taxes	7,914,041	7,166,507	-9.45%
12	409.1 Income Taxes - Federal	none/n.a.	none/n.a.	#VALUE!
13	- Other	(154,679)	482,235	411.77%
14	410.1 Provision for Deferred Income Taxes	none/n.a.	none/n.a.	#VALUE!
15	411.1 (Less) Provision for Def. Inc. Taxes - Cr.	none/n.a.	none/n.a.	#VALUE!
16	411.4 Investment Tax Credit Adjustments	none/n.a.	none/n.a.	#VALUE!
17	411.6 (Less) Gains from Disposition of Utility Plant	none/n.a.	none/n.a.	#VALUE!
18	411.7 Losses from Disposition of Utility Plant	none/n.a.	none/n.a.	#VALUE!
19				
20	**TOTAL Utility Operating Expenses**	52,281,686	49,447,342	-5.42%
21	**NET UTILITY OPERATING INCOME**	(33,573,893)	(49,414,030)	-47.18%

MONTANA REVENUES

SCHEDULE 9

	Account Number & Title	Last Year	This Year	% Change
1	Sales of Electricity			
2	440 Residential	5,994	5,543	-7.52%
3	442 Commercial & Industrial - Small	1,932	1,477	-23.55%
4	Commercial & Industrial - Large			
5	444 Public Street & Highway Lighting			
6	445 Other Sales to Public Authorities			
7	446 Sales to Railroads & Railways			
8	448 Interdepartmental Sales	18,122	26,292	45.08%
9				
10	**TOTAL Sales to Ultimate Consumers**	26,048	33,312	27.89%
11	447 Sales for Resale	18,558,350		-100.00%
12				
13	**TOTAL Sales of Electricity**	18,584,398	33,312	-99.82%
14	449.1 (Less) Provision for Rate Refunds			
15				
16	**TOTAL Revenue Net of Provision for Refunds**	18,584,398	33,312	-99.82%
17	Other Operating Revenues			
18	450 Forfeited Discounts & Late Payment Revenues			
19	451 Miscellaneous Service Revenues			
20	453 Sales of Water & Water Power			
21	454 Rent From Electric Property	58,581		-100.00%
22	455 Interdepartmental Rents			
23	456 Other Electric Revenues	64,814		-100.00%
24				
25	**TOTAL Other Operating Revenues**	123,395		-100.00%
26	**Total Electric Operating Revenues**	18,707,793	33,312	-99.82%

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2009

	Account Number & Title	Last Year	This Year	% Change
1	Power Production Expenses			
2				
3	Steam Power Generation			
4	Operation			
5	500 Operation Supervision & Engineering	177,078	185,385	4.69%
6	501 Fuel	19,748,528	13,449,219	-31.90%
7	502 Steam Expenses	1,322,868	2,065,287	56.12%
8	503 Steam from Other Sources			
9	504 (Less) Steam Transferred - Cr.			
10	505 Electric Expenses	44,456	33,208	-25.30%
11	506 Miscellaneous Steam Power Expenses	2,945,137	2,322,513	-21.14%
12	507 Rents	38,367	29,773	-22.40%
13				
14	TOTAL Operation - Steam	24,276,434	18,085,385	-25.50%
15				
16	Maintenance			
17	510 Maintenance Supervision & Engineering	345,391	392,966	13.77%
18	511 Maintenance of Structures	435,332	505,807	16.19%
19	512 Maintenance of Boiler Plant	3,752,319	3,954,168	5.38%
20	513 Maintenance of Electric Plant	322,054	1,453,190	351.23%
21	514 Maintenance of Miscellaneous Steam Plant	471,195	737,339	56.48%
22				
23	TOTAL Maintenance - Steam	5,326,291	7,043,470	32.24%
24				
25	**TOTAL Steam Power Production Expenses**	29,602,725	25,128,855	-15.11%
26				
27	Nuclear Power Generation			
28	Operation			
29	517 Operation Supervision & Engineering			
30	518 Nuclear Fuel Expense			
31	519 Coolants & Water			
32	520 Steam Expenses			
33	521 Steam from Other Sources			
34	522 (Less) Steam Transferred - Cr.			
35	523 Electric Expenses			
36	524 Miscellaneous Nuclear Power Expenses			
37	525 Rents			
38				
39	TOTAL Operation - Nuclear			
40				
41	Maintenance			
42	528 Maintenance Supervision & Engineering			
43	529 Maintenance of Structures			
44	530 Maintenance of Reactor Plant Equipment			
45	531 Maintenance of Electric Plant			
46	532 Maintenance of Miscellaneous Nuclear Plant			
47				
48	TOTAL Maintenance - Nuclear			
49				
50	**TOTAL Nuclear Power Production Expenses**			

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2009

	Account Number & Title	Last Year	This Year	% Change
1	Power Production Expenses -continued			
2	Hydraulic Power Generation			
3	Operation			
4	535 Operation Supervision & Engineering	89,326	89,853	0.59%
5	536 Water for Power			
6	537 Hydraulic Expenses	50,496	10,924	-78.37%
7	538 Electric Expenses	981,924	1,208,611	23.09%
8	539 Miscellaneous Hydraulic Power Gen. Expenses	162,303	130,016	-19.89%
9	540 Rents			
10				
11	TOTAL Operation - Hydraulic	1,284,049	1,439,404	12.10%
12				
13	Maintenance			
14	541 Maintenance Supervision & Engineering	37,341	27,782	-25.60%
15	542 Maintenance of Structures	99,777	105,765	6.00%
16	543 Maint. of Reservoirs, Dams & Waterways	33,132	22,631	-31.69%
17	544 Maintenance of Electric Plant	883,830	375,493	-57.52%
18	545 Maintenance of Miscellaneous Hydro Plant	37,437	1,661,857	4339.08%
19				
20	TOTAL Maintenance - Hydraulic	1,091,517	2,193,528	100.96%
21				
22	**TOTAL Hydraulic Power Production Expenses**	2,375,566	3,632,932	52.93%
23				
24	Other Power Generation			
25	Operation			
26	546 Operation Supervision & Engineering			
27	547 Fuel			
28	548 Generation Expenses			
29	549 Miscellaneous Other Power Gen. Expenses			
30	550 Rents			
31				
32	TOTAL Operation - Other			
33				
34	Maintenance			
35	551 Maintenance Supervision & Engineering			
36	552 Maintenance of Structures			
37	553 Maintenance of Generating & Electric Plant			
38	554 Maintenance of Misc. Other Power Gen. Plant			
39				
40	TOTAL Maintenance - Other			
41				
42	**TOTAL Other Power Production Expenses**			
43				
44	Other Power Supply Expenses			
45	555 Purchased Power			
46	556 System Control & Load Dispatching			
47	557 Other Expenses			
48				
49	TOTAL Other Power Supply Expenses			
50				
51	**TOTAL Power Production Expenses**	31,978,291	28,761,787	-10.06%

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2009

	Account Number & Title	Last Year	This Year	% Change
1	Transmission Expenses			
2	Operation			
3	560 Operation Supervision & Engineering	12,145	20,351	67.57%
4	561 Load Dispatching	21,180	24,601	16.15%
5	562 Station Expenses	3,084	5,763	86.87%
6	563 Overhead Line Expenses	10,016	206,300	1959.70%
7	564 Underground Line Expenses			
8	565 Transmission of Electricity by Others			
9	566 Miscellaneous Transmission Expenses			
10	567 Rents	68,206	75,735	11.04%
11				
12	TOTAL Operation - Transmission	114,631	332,750	190.28%
13	Maintenance			
14	568 Maintenance Supervision & Engineering	12,075	37,611	211.48%
15	569 Maintenance of Structures	6,633	750	-88.69%
16	570 Maintenance of Station Equipment	36,434	107,122	194.02%
17	571 Maintenance of Overhead Lines	464,504	183,246	-60.55%
18	572 Maintenance of Underground Lines			
19	573 Maintenance of Misc. Transmission Plant			
20				
21	TOTAL Maintenance - Transmission	519,646	328,729	-36.74%
22				
23	**TOTAL Transmission Expenses**	634,277	661,479	4.29%
24				
25	Distribution Expenses			
26	Operation			
27	580 Operation Supervision & Engineering			
28	581 Load Dispatching			
29	582 Station Expenses			
30	583 Overhead Line Expenses	1,552		-100.00%
31	584 Underground Line Expenses			
32	585 Street Lighting & Signal System Expenses			
33	586 Meter Expenses			
34	587 Customer Installations Expenses			
35	588 Miscellaneous Distribution Expenses			
36	589 Rents			
37				
38	TOTAL Operation - Distribution	1,552		-100.00%
39	Maintenance			
40	590 Maintenance Supervision & Engineering			
41	591 Maintenance of Structures			
42	592 Maintenance of Station Equipment			
43	593 Maintenance of Overhead Lines			
44	594 Maintenance of Underground Lines			
45	595 Maintenance of Line Transformers			
46	596 Maintenance of Street Lighting, Signal Systems			
47	597 Maintenance of Meters			
48	598 Maintenance of Miscellaneous Dist. Plant			
49				
50	TOTAL Maintenance - Distribution			
51				
52	**TOTAL Distribution Expenses**	1,552		-100.00%

MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2009

	Account Number & Title	Last Year	This Year	% Change
1	Customer Accounts Expenses			
2	Operation			
3	901 Supervision			
4	902 Meter Reading Expenses			
5	903 Customer Records & Collection Expenses			
6	904 Uncollectible Accounts Expenses			
7	905 Miscellaneous Customer Accounts Expenses			
8				
9	TOTAL Customer Accounts Expenses			
10				
11	Customer Service & Information Expenses			
12	Operation			
13	907 Supervision			
14	908 Customer Assistance Expenses			
15	909 Informational & Instructional Adv. Expenses			
16	910 Miscellaneous Customer Service & Info. Exp.			
17				
18	TOTAL Customer Service & Info Expenses			
19				
20	Sales Expenses			
21	Operation			
22	911 Supervision			
23	912 Demonstrating & Selling Expenses			
24	913 Advertising Expenses			
25	916 Miscellaneous Sales Expenses			
26				
27	TOTAL Sales Expenses			
28				
29	Administrative & General Expenses			
30	Operation			
31	920 Administrative & General Salaries			
32	921 Office Supplies & Expenses			
33	922 (Less) Administrative Expenses Transferred - Cr.			
34	923 Outside Services Employed			
35	924 Property Insurance			
36	925 Injuries & Damages			
37	926 Employee Pensions & Benefits			
38	927 Franchise Requirements			
39	928 Regulatory Commission Expenses			
40	929 (Less) Duplicate Charges - Cr.			
41	930.1 General Advertising Expenses		18,046	#DIV/0!
42	930.2 Miscellaneous General Expenses			
43	931 Rents			
44				
45	TOTAL Operation - Admin. & General		18,046	#DIV/0!
46	Maintenance			
47	935 Maintenance of General Plant	18,041	17,762	-1.55%
48				
49	**TOTAL Administrative & General Expenses**	18,041	35,808	98.48%
50				
51	**TOTAL Operation & Maintenance Expenses**	32,632,161	29,459,074	-9.72%

Company Name: Avista Corporation **SCHEDULE 11**

MONTANA TAXES OTHER THAN INCOME

Year: 2009

	Description of Tax	Last Year	This Year	% Change
1	Payroll Taxes			
2	Superfund			
3	Secretary of State			
4	Montana Consumer Counsel	46,489	(20,548)	-144.20%
5	Motor Vehicle Tax	3,287	4,068	23.76%
6	KWH Tax	1,183,035	1,008,877	-14.72%
7	Property Taxes	6,676,978	6,164,981	-7.67%
8	Public Commission Tax	24	5,907	24512.50%
9	Colstrip Generation Tax	4,228	3,222	-23.79%
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45				
46				
47				
48				
49				
50				
51	**TOTAL MT Taxes Other Than Income**	7,914,041	7,166,507	-9.45%

PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES

Year: 2009

	Name of Recipient	Nature of Service	Total Company	Montana	% Montana
1	ACUREN INSPECTION INC	Inspection	148,443		
2	AREVA T&D INC	consulting	136,476		
3	ASSETWORKS INC	consulting	80,809		
4	BAIN & COMPANY INC	consulting	218,500		
5	BOOZ & COMPANY INC	consulting	180,311		
6	BROWN CONTRACTING & DEVELOPMENT	Engineering	515,504		
7	BT COUNTERPANE INTERNET SECURITY INC	consulting IT	76,522		
8	CERIUM NETWORKS	consulting IT	394,508		
9	CHAPMAN AND CUTLER	legal	148,097		
10	COATES KOKES	Engineering	102,641		
11	COFFMAN ENGINEERS	Engineering	305,065		
12	D & H CONSULTING INC	consulting	75,499		
13	DAVID EVANS & ASSOCIATES INC	Engineering	122,881		
14	DAVIS WRIGHT TREMAINE LLP	legal	1,053,362		
15	DAVIS WRIGHT TREMAINE LLP	legal	214,784		
16	DELOITTE & TOUCHE LLP	audit	1,354,915		
17	DEWEY & LEBOEUF LLP	legal	393,041		
18	DEWEY & LEBOEUF LLP	legal	573,886		
19	GARD COMMUNICATIONS	consulting	352,822		
20	GARTNER INC	consulting IT	162,000		
21	GILLESPIE PRUDHON & ASSOCIATES INC	Engineering	456,878		
22	GOLDER ASSOCIATES INC	environmental consulting	280,572		
23	H2E INC	consulting	170,011		
24	HANNA & ASSOCIATES INC	consulting	250,065		
25	HATCH ACRES CORPORATION	Engineering	88,703		
26	HDR ENGINEERING, INC.	Engineering	168,383		
27	HICKEY BROTHERS FISHERIES LLC	consulting fish passage	262,200		
28	HOFFBUHR & ASSOCIATES INC	surveying and mapping servic	95,036		
29	IDAHO DEPT OF FISH & GAME	Bull trout education program	267,386		
30	INTERVOICE	consulting	1,011,871		
31	JAMES A CAROTHERS	consulting	243,000		
32	KLUNDT HOSMER DESIGN	annual report design	94,127		
33	MARKET DECISIONS CORPORATION	consulting	91,915		
34	MERCER HEALTH & BENEFITS LLC	employee benefit consulting	83,333		
35	MONTANA FISH WILDLIFE & PARKS	consulting	114,290		
36	NORMANDEAU ASSOCIATES INC	environmental consulting	88,406		
37	NORTHWEST POWER POOL	consulting	108,584		
38	NORTON CORROSION LIMITED LLC	Engineering	136,132		
39	NRC ENVIRONMENTAL SERVICES	environmental consulting	1,016,027		
40	OPEN ACCESS TECHNOLOGY INTL	consulting IT	221,381		
41	PAINE HAMBLEN LLP	legal	475,012		
42	PILLSBURY WINTHROP SHAW PITTMAN	legal	86,900		
43	PILLSBURY WINTHROP SHAW PITTMAN	legal	100,183		
44	REGULUS INTEGRATED SOLUTIONS LLC	consulting	394,541		
45	ROBIN CHARLWOOD & ASSOCIATES PLLC	Engineering	82,652		
46	STOEL RIVES LLP	legal	264,736		
47	SURDEX CORPORATION	consulting	118,000		
48	TAYLOR ENGINEERING INC	Engineering	106,440		
49	TEREX UTILITIES INC	consulting	134,332		
50	THE ULTIMATE SOFTWARE GROUP INC	consulting IT	237,415		
51	THOMSON REUTERS (PROPERTY TAX SVS) INC	consulting	575,000		
52	TOWERS PERRIN	consulting	112,491		
53	TWISTED PINES LANDSCAPE DESIGN & CONST	consulting	285,900		
54	U S FISH & WILDLIFE SERVICE	consulting	171,586		
55	UBS SECURITIES LLC	consulting	108,723		
56	USU AG	consulting	189,510		
57	VAN NESS FELDMAN	legal	159,815		
58	VENTYX INC	consulting	140,672		
59	VILLAGE CONTRACTING LLC	Engineering	98,152		
60	WASHINGTON GROUP INTL INC	Engineering	312,956		
61	WESTERN ELECTRICITY	consulting	528,533		
62	WINSTON & STRAWN LLP	legal	99,308		
63	**TOTAL Payments for Services**		15,602,270		

POLITICAL ACTION COMMITTEES / POLITICAL CONTRIBUTIONS Year: 2009

	Description	Total Company	Montana	% Montana
1				
2				
3	None			
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45				
46				
47				
48				
49				
50	**TOTAL Contributions**			

Pension Costs

Year: 2009

1	Plan Name The Retirement Plan for Employees of Avista Corporation.			
2	Defined Benefit Plan? Yes	Defined Contribution Plan? No		
3	Actuarial Cost Method? Yes	IRS Code: 001		
4	Annual Contribution by Employer: Varies	Is the Plan Over Funded? No		
5				
	Item	**Current Year**	**Last Year**	**% Change**
6	**Change in Benefit Obligation**			
7	Benefit obligation at beginning of year	334,399	303,614	-9.21%
8	Service cost	10,186	9,879	-3.01%
9	Interest Cost	20,604	19,633	-4.71%
10	Plan participants' contributions			
11	Amendments			
12	Actuarial Gain	8,816	17,622	99.89%
13	Benefits paid	(15,958)	(16,349)	-2.45%
14	Expenses paid			
15	Benefit obligation at end of year	358,047	334,399	-6.60%
16	**Change in Plan Assets**			
17	Fair value of plan assets at beginning of year	190,638	242,561	27.24%
18	Actual return on plan assets	50,052	(63,574)	-227.02%
19	Acquisition			
20	Employer contribution	48,000	28,000	-41.67%
21	Benefits paid	(15,958)	(16,349)	-2.45%
22	Expenses paid			
23	Fair value of plan assets at end of year	272,732	190,638	-30.10%
24	**Funded Status**	(85,315)	(143,761)	-68.51%
25	Unrecognized net actuarial loss	121,920	155,727	27.73%
26	Unrecognized prior service cost	1,790	2,444	36.54%
27	Unrecognized net transition obligation/(asset)			
28	Prepaid (accrued) benefit cost	38,395	14,410	-62.47%
29				
30	**Weighted-average Assumptions as of Year End**			
31	Discount rate	6.35%	6.25%	-1.57%
32	Expected return on plan assets	8.50%	8.50%	
33	Rate of compensation increase	4.65%	4.72%	1.51%
34				
35	**Components of Net Periodic Benefit Costs**			
36	Service cost	10,186	9,879	-3.01%
37	Interest cost	20,604	19,633	-4.71%
38	Expected return on plan assets	(17,612)	(21,138)	-20.02%
39	Transition (asset)/obligation recognition			
40	Amortization of prior service cost	653	654	0.15%
41	Recognized net actuarial loss	10,183	2,994	-70.60%
42	Net periodic benefit cost	24,014	12,022	-49.94%
43				
44	**Montana Intrastate Costs:**			
45	Pension Costs			
46	Pension Costs Capitalized	not available by state		
47	Accumulated Pension Asset (Liability) at Year End			
48	**Number of Company Employees:**			
49	Covered by the Plan	2,573	2,587	0.54%
50	Not Covered by the Plan			
51	Active	1,294	1,328	2.63%
52	Retired	999	969	-3.00%
53	Deferred Vested Terminated	280	290	3.57%

Other Post Employment Benefits (OPEBS)

Year: 2009

	Item	Current Year	Last Year	% Change
1	**Regulatory Treatment:**			
2	Commission authorized - most recent			
3	Docket number: ___________			
4	Order number: ____________			
5	Amount recovered through rates			
6	**Weighted-average Assumptions as of Year End**			
7	Discount rate	6.00%	6.25%	4.17%
8	Expected return on plan assets	8.50%	8.50%	
9	Medical Cost Inflation Rate	6.00%	6.00%	
10	Actuarial Cost Method		Proj Unit Credit	#VALUE!
11	Rate of compensation increase			
12	**List each method used to fund OPEBs (ie: VEBA, 401(h)) and if tax advantaged:**			
13				
14				
15	**Describe any Changes to the Benefit Plan:**			
16				
17	**TOTAL COMPANY**			
18	**Change in Benefit Obligation**			
19	Benefit obligation at beginning of year	38,953	34,352	-11.81%
20	Service cost	803	772	-3.86%
21	Interest Cost	2,364	2,371	0.30%
22	Plan participants' contributions	98	365	272.45%
23	Amendments			
24	Actuarial Gain	1,676	5,611	234.79%
25	Benefits paid	(4,334)	(4,518)	-4.25%
26	Expenses paid			
27	Benefit obligation at end of year	39,560	38,953	-1.53%
28	**Change in Plan Assets**			
29	Fair value of plan assets at beginning of year	16,048	22,718	41.56%
30	Actual return on plan assets	4,346	(6,670)	-253.47%
31	Acquisition			
32	Employer contribution			
33	Benefits paid			
34	Expenses paid			
35	Fair value of plan assets at end of year	20,394	16,048	-21.31%
36	**Funded Status**	(19,166)	(22,905)	-19.51%
37	Unrecognized net actuarial loss	15,772	16,905	7.18%
38	Unrecognized prior service cost	(1,303)	2,021	255.10%
39	Prepaid (accrued) benefit cost	(4,697)	(3,979)	15.29%
40	**Components of Net Periodic Benefit Costs**			
41	Service cost	803	772	-3.86%
42	Interest cost	2,364	2,371	0.30%
43	Expected return on plan assets	(1,364)	(1,931)	-41.57%
44	Amortization of prior service cost	356	356	
45	Recognized net actuarial loss	1,279	575	-55.04%
46	Net periodic benefit cost	3,438	2,143	-37.67%
47	**Accumulated Post Retirement Benefit Obligation**			
48	Amount Funded through VEBA	39,560	38,953	-1.53%
49	Amount Funded through 401(h)			
50	Amount Funded through Other ________________			
51	TOTAL	39,560	38,953	-1.53%
52	Amount that was tax deductible - VEBA			
53	Amount that was tax deductible - 401(h)			
54	Amount that was tax deductible - Other ___________			
55	TOTAL	39,560	38,953	-1.53%

Company Name: Avista Corporation

SCHEDULE 15
Page 2 of 2

Other Post Employment Benefits (OPEBS) Continued

Year: 2009

	Item	Current Year	Last Year	% Change
1	**Number of Company Employees:**			
2	Covered by the Plan	2,106	2,118	0.57%
3	Not Covered by the Plan			
4	Active	1,296	1,336	3.09%
5	Retired	810	782	-3.46%
6	Spouses/Dependants covered by the Plan			
7	**Montana**			
8	**Change in Benefit Obligation**			
9	Benefit obligation at beginning of year			
10	Service cost			
11	Interest Cost	not available by state		
12	Plan participants' contributions			
13	Amendments			
14	Actuarial Gain			
15	Acquisition			
16	Benefits paid			
17	Benefit obligation at end of year			
18	**Change in Plan Assets**			
19	Fair value of plan assets at beginning of year			
20	Actual return on plan assets			
21	Acquisition			
22	Employer contribution			
23	Plan participants' contributions			
24	Benefits paid			
25	Fair value of plan assets at end of year			
26	**Funded Status**			
27	Unrecognized net actuarial loss			
28	Unrecognized prior service cost			
29	Prepaid (accrued) benefit cost			
30	**Components of Net Periodic Benefit Costs**			
31	Service cost			
32	Interest cost	not available by state		
33	Expected return on plan assets			
34	Amortization of prior service cost			
35	Recognized net actuarial loss			
36	Net periodic benefit cost			
37	**Accumulated Post Retirement Benefit Obligation**			
38	Amount Funded through VEBA			
39	Amount Funded through 401(h)			
40	Amount Funded through other ___________________			
41	TOTAL			
42	Amount that was tax deductible - VEBA			
43	Amount that was tax deductible - 401(h)			
44	Amount that was tax deductible - Other			
45	TOTAL			
46	**Montana Intrastate Costs:**			
47	Pension Costs			
48	Pension Costs Capitalized			
49	Accumulated Pension Asset (Liability) at Year End			
50	**Number of Montana Employees:**			
51	Covered by the Plan			
52	Not Covered by the Plan			
53	Active			
54	Retired			
55	Spouses/Dependants covered by the Plan			

TOP TEN MONTANA COMPENSATED EMPLOYEES (ASSIGNED OR ALLOCATED)

Line No.	Name/Title	Base Salary	Bonuses	Other	Total Compensation	Total Compensation Last Year	% Increase Total Compensation
1	Confidential Schedule						
2							
3							
4							
5							
6							
7							
8							
9							
10							

COMPENSATION OF TOP 5 CORPORATE EMPLOYEES - SEC INFORMATION

Line No.	Name/Title	Base Salary	Bonuses	Other	Total Compensation	Total Compensation Last Year	% Increase Total Compensation
1	S. L. Morris Chairman of the Board, President & Chief Executive Officer	630,001	582,026	1,815,991	3,028,018	2,685,369	13%
2	M. T. Thies Senior Vice President and Chief Financial Officer employment began September 29, 2008	314,998	194,009	322,227	831,234	366,646	127%
3	M.M. Durkin Senior Vice President General Counsel and Chief Compliance Officer	274,999	169,373	346,718	791,090	728,321	9%
4	K.S. Feltes Senior Vice President and Corporate Secretary	240,001	147,816	371,190	759,007	696,159	9%
5	D.P. Vermillion Senior Vice President Not an NEO in 2008	289,230	148,843	295,856	733,929	N/A	#VALUE!
	Other compensation includes stock-based awards and the change in pension and non-qualified deferred compensation.						

BALANCE SHEET

Year: 2009

	Account Number & Title	Last Year	This Year	% Change
1	**Assets and Other Debits**			
2	Utility Plant			
3	101 Electric Plant in Service	3,313,806,232	3,520,534,663	-6%
4	101.1 Property Under Capital Leases	2,419,182	1,903,329	27%
5	102 Electric Plant Purchased or Sold			
6	104 Electric Plant Leased to Others			
7	105 Electric Plant Held for Future Use	1,631,351	1,631,351	
8	106 Completed Constr. Not Classified - Electric			
9	107 Construction Work in Progress - Electric	75,568,224	57,217,478	32%
10	108 (Less) Accumulated Depreciation	(1,105,346,502)	(1,174,736,479)	6%
11	111 (Less) Accumulated Amortization	(17,851,932)	(24,651,168)	28%
12	114 Electric Plant Acquisition Adjustments	22,211,433	22,122,748	0%
13	115 (Less) Accum. Amort. Elec. Acq. Adj.	(19,379,703)	(20,490,275)	5%
14	120 Nuclear Fuel (Net)			
15	**TOTAL Utility Plant**	2,273,058,285	2,383,531,647	-5%
16				
17	**Other Property & Investments**			
18	121 Nonutility Property	4,991,551	5,031,620	-1%
19	122 (Less) Accum. Depr. & Amort. for Nonutil. Prop.	(890,639)	(897,684)	1%
20	123 Investments in Associated Companies	13,903,000	12,047,000	15%
21	123.1 Investments in Subsidiary Companies	77,487,962	81,243,239	-5%
22	124 Other Investments	26,240,546	23,798,439	10%
23	128 Other Special Funds	10,234,544	11,558,301	-11%
	Long-Term Derivative Instruments	49,312,596	45,482,748	8%
24	**TOTAL Other Property & Investments**	181,279,560	178,263,663	2%
25				
26	**Current & Accrued Assets**			
27	131 Cash	1,674,372	2,462,480	-32%
28	132-134 Special Deposits	1,600,000	1,630,323	-2%
29	135 Working Funds	619,853	848,613	-27%
30	136 Temporary Cash Investments	2,684,444	652,010	312%
31	141 Notes Receivable	63,451	629,625	-90%
32	142 Customer Accounts Receivable	207,867,900	188,271,550	10%
33	143 Other Accounts Receivable	6,188,617	6,484,963	-5%
34	144 (Less) Accum. Provision for Uncollectible Accts.	(5,844,603)	(3,710,770)	-58%
35	145 Notes Receivable - Associated Companies			
36	146 Accounts Receivable - Associated Companies	120,021	101,231	19%
37	151 Fuel Stock	3,673,039	4,294,013	-14%
38	152 Fuel Stock Expenses Undistributed			
39	153 Residuals			
40	154 Plant Materials and Operating Supplies	17,455,835	18,386,509	-5%
41	155 Merchandise			
42	156 Other Material & Supplies			
43	157 Nuclear Materials Held for Sale			
44	163 Stores Expense Undistributed		12,832	-100%
	164 Gas Storage	30,720,371	12,706,763	142%
45	165 Prepayments	8,415,670	9,985,760	-16%
46	171 Interest & Dividends Receivable	10,934	197,040	-94%
47	172 Rents Receivable	646,271	553,237	17%
48	174 Miscellaneous Current & Accrued Assets	178,045	454,418	-61%
	176 Derivative Instruments Assets - Hedges	61,421,267	53,240,001	15%
49	Long-Term Derivative Instruments	(49,312,596)	(45,482,748)	-8%
50	**TOTAL Current & Accrued Assets**	288,182,891	251,717,850	14%

Company Name: Avista Corporation **SCHEDULE 18**

BALANCE SHEET

Year: 2009

	Account Number & Title		Last Year	This Year	% Change
1					
2		**Assets and Other Debits (cont.)**			
3					
4	**Deferred Debits**				
5					
6	181	Unamortized Debt Expense	15,852,599	15,732,877	1%
7	182.1	Extraordinary Property Losses			
8	182.2	Unrecovered Plant & Regulatory Study Costs			
9	182.3	Other Regulatory Assets	455,580,547	352,616,516	
10	183	Prelim. Survey & Investigation Charges	3,088,816	3,346,452	-8%
11	184	Clearing Accounts			
12	185	Temporary Facilities			
13	186	Miscellaneous Deferred Debits	32,008,980	26,105,547	23%
14	187	Deferred Losses from Disposition of Util. Plant			
15	188	Research, Devel. & Demonstration Expend.			
16	189	Unamortized Loss on Reacquired Debt	17,151,844	15,196,145	13%
17	190	Accumulated Deferred Income Taxes	131,055,525	91,975,547	42%
	191	Unrecovered Purchased Gas Costs	(18,646,016)	(39,952,004)	
18		**TOTAL Deferred Debits**	636,092,295	465,021,080	37%
19					
20		**TOTAL Assets & Other Debits**	3,378,613,031	3,278,534,240	3%
		Account Title	Last Year	This Year	% Change
20					
21		**Liabilities and Other Credits**			
22					
23	**Proprietary Capital**				
24					
25	201	Common Stock Issued	755,903,119	759,057,747	0%
26	202	Common Stock Subscribed			
27	204	Preferred Stock Issued	-	-	
28	205	Preferred Stock Subscribed			
29	207	Premium on Capital Stock			
30	211	Miscellaneous Paid-In Capital	19,170,532	17,498,634	10%
31	213	(Less) Discount on Capital Stock			
32	214	(Less) Capital Stock Expense	(87,394)	2,090,960	-104%
33	215	Appropriated Retained Earnings	253,478,332	295,862,246	-14%
34	216	Unappropriated Retained Earnings	(25,488,897)	(20,871,862)	-22%
35	217	(Less) Reacquired Capital Stock			
	219	Accumulated Other Comprehensive Income	(6,092,318)	(2,350,286)	
36		**TOTAL Proprietary Capital**	996,883,374	1,051,287,439	-5%
37					
38	**Long Term Debt**				
39					
40	221	Bonds	824,970,979	1,070,256,423	-23%
41	222	(Less) Reacquired Bonds			
42	223	Advances from Associated Companies	114,603,000	51,547,000	122%
43	224	Other Long Term Debt			
44	225	Unamortized Premium on Long Term Debt	239,850	230,967	4%
45	226	(Less) Unamort. Discount on L-Term Debt-Dr.	(1,752,256)	(2,167,570)	19%
46		**TOTAL Long Term Debt**	938,061,573	1,119,866,820	-16%

Company Name: **Avista Corporation** **SCHEDULE 18**

BALANCE SHEET

Year: 2009

	Account Number & Title		Last Year	This Year	% Change
1					
2		**Total Liabilities and Other Credits (cont.)**			
3					
4	**Other Noncurrent Liabilities**				
5					
6	227	Obligations Under Cap. Leases - Noncurrent			
7	228.1	Accumulated Provision for Property Insurance			
8	228.2	Accumulated Provision for Injuries & Damages	1,579,821	1,650,500	-4%
9	228.3	Accumulated Provision for Pensions & Benefits	184,587,850	123,281,094	50%
10	228.4	Accumulated Misc. Operating Provisions	2,936,173	2,916,673	1%
11		Long-Term Derivative Instruments	7,140,857	2,871,255	149%
	230	Asset Retirement Obligations	4,208,327	3,971,453	
12		**TOTAL Other Noncurrent Liabilities**	200,453,028	134,690,975	49%
13					
14	**Current & Accrued Liabilities**				
15					
16	231	Notes Payable	250,000,000	87,000,000	187%
17	232	Accounts Payable	153,032,408	114,930,110	33%
18	233	Notes Payable to Associated Companies	2,854,178	6,882,247	-59%
19	234	Accounts Payable to Associated Companies	737,710	724,582	2%
20	235	Customer Deposits	6,979,171	8,140,853	-14%
21	236	Taxes Accrued	6,105,577	2,222,626	175%
22	237	Interest Accrued	10,871,471	13,476,434	-19%
23	238	Dividends Declared			
24	241	Tax Collections Payable	(16,874)	147,574	-111%
25	242	Miscellaneous Current & Accrued Liabilities	32,188,393	55,461,901	-42%
26	243	Obligations Under Cap. Leases - Current	75,206		#DIV/0!
27	245	Derivative Instrument Liabilities - Hedges	78,603,554	19,008,149	314%
28		Long-Term Derivative Instruments	(7,140,857)	(2,871,255)	-149%
29		**TOTAL Current & Accrued Liabilities**	534,289,937	305,123,221	75%
30					
31	**Deferred Credits**				
32					
33	252	Customer Advances for Construction	1,263,086	1,280,331	-1%
34	253	Other Deferred Credits	24,985,882	22,330,799	12%
35	254	Other Regulatory Liabilities	55,429,522	61,709,913	-10%
36	255	Accumulated Deferred Investment Tax Credits	373,728	5,632,508	-93%
37	257	Unamortized Gain on Reacquired Debt	3,237,373	2,957,425	9%
38	281-283	Accumulated Deferred Income Taxes	623,635,528	573,654,809	9%
39		**TOTAL Deferred Credits**	708,925,119	667,565,785	6%
40					
41	**TOTAL LIABILITIES & OTHER CREDITS**		3,378,613,031	3,278,534,240	3%

NOTES TO FINANCIAL STATEMENTS

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nature of Business

Avista Corporation (Avista Corp. or the Company) is an energy company engaged in the generation, transmission and distribution of energy, as well as other energy-related businesses. Avista Corp. generates, transmits and distributes electricity in parts of eastern Washington and northern Idaho. In addition, Avista Corp. has electric generating facilities in Montana and northern Oregon. Avista Corp. also provides natural gas distribution service in parts of eastern Washington and northern Idaho, as well as parts of northeast and southwest Oregon. Avista Capital, Inc. (Avista Capital), a wholly owned subsidiary of Avista Corp., is the parent company of all of the subsidiary companies including Avista Energy, Inc. (Avista Energy) and Advantage IQ, Inc. (Advantage IQ), a 74 percent owned subsidiary as of December 31, 2009. Avista Energy was an electricity and natural gas marketing, trading and resource management business. On June 30, 2007, Avista Energy completed the sale of substantially all of its contracts and ongoing operations. See Note 3 for further information. Advantage IQ is a provider of facility information and cost management services for multi-site customers throughout North America.

Accounting Standards Codification

In June 2009, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards (SFAS) No. 168, "The Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles – a replacement of FASB Statement No. 162." This statement replaces all previously issued accounting standards and establishes the FASB Accounting Standards Codification (ASC). The ASC is the single source of authoritative nongovernmental accounting principles generally accepted in the United States of America (U.S. GAAP) and is effective for all interim and annual periods ending after September 15, 2009. All existing accounting standards documents were superseded. All other accounting literature not included in the ASC is considered nonauthoritative. The adoption of the ASC did not have any impact on the Company's financial condition, results of operations and cash flows, as the ASC did not change existing U.S. GAAP. The adoption of the ASC only resulted in changes to the Company's financial statemeut disclosure references. In order to facilitate the transition to the ASC, the Company has elected to show references to U.S. GAAP within this report prior to the ASC along with a parenthetical ASC reference.

Basis of Reporting

The financial statements include the assets, liabilities, revenues and expenses of the Company and have been prepared in accordance with the accounting requirements of the Federal Energy Regulatory Commission (FERC) as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than U.S. GAAP. As required by the FERC, the Company accounts for its investment in majority-owned subsidiaries on the equity method rather than consolidating the assets, liabilities, revenues, and expenses of these subsidiaries, as required by U.S. GAAP. The accompanying financial statements include the Company's proportionate share of utility plant and related operations resulting from its interests in jointly owned plants. In addition, under the requirements of the FERC, there are differences from U.S. GAAP in the presentation of (1) current portion of long-term debt (2) assets and liabilities for cost of removal of assets, (3) assets held for sale, (4) regulatory assets and liabilities, (5) deferred income taxes and (6) comprehensive income.

Use of Estimates

The preparation of the financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect amounts reported in the financial statements. Significant estimates include:

- determining the market value of energy commodity derivative assets and liabilities,
- pension and other postretirement benefit plan obligations,
- contingent liabilities,
- recoverability of regulatory assets,
- stock-based compensation, and
- unbilled revenues.

Changes in these estimates and assumptions are considered reasonably possible and may have a material effect on the financial statements and thus actual results could differ from the amounts reported and disclosed herein.

System of Accounts

The accounting records of the Company's utility operations are maintained in accordance with the uniform system of accounts prescribed by the FERC and adopted by the state regulatory commissions in Washington, Idaho, Montana and Oregon.

Regulation
The Company is subject to state regulation in Washington, Idaho, Montana and Oregon. The Company is also subject to federal regulation by the FERC.

Operating Revenues
Revenues related to the sale of energy are generally recorded when service is rendered or energy is delivered to customers. The determination of the energy sales to individual customers is based on the reading of their meters, which occurs on a systematic basis throughout the month. At the end of each calendar month, the amount of energy delivered to customers since the date of the last meter reading is estimated and the corresponding unbilled revenue is estimated and recorded. Accounts receivable includes unbilled energy revenues of $89.6 million as of December 31, 2009 and $84.3 million (net of $11.4 million of unbilled receivables sold) as of December 31, 2008. See Note 5 for information related to the sale of accounts receivable.

Advertising Expenses
The Company expenses advertising costs as incurred. Advertising expenses were not a material portion of the Company's operating expenses in 2009 and 2008.

Depreciation
For utility operations, depreciation expense is estimated by a method of depreciation accounting utilizing composite rates for utility plant. Such rates are designed to provide for retirements of properties at the expiration of their service lives. For utility operations, the ratio of depreciation provisions to average depreciable property was 2.78 percent in 2009 and 2.77 percent in 2008.

The average service lives for the following broad categories of utility plant in service are:

- electric thermal production - 32 years,
- hydroelectric production - 74 years,
- electric transmission - 51 years,
- electric distribution - 41 years, and
- natural gas distribution property - 53 years.

Taxes Other Than Income Taxes
Taxes other than income taxes include state excise taxes, city occupational and franchise taxes, real and personal property taxes and certain other taxes not based on net income. These taxes are generally based on revenues or the value of property. Utility related taxes collected from customers (primarily state excise taxes and city utility taxes) are recorded as operating revenue and expense and totaled $56.8 million in 2009 and $53.9 million in 2008.

Allowance for Funds Used During Construction
The Allowance for Funds Used During Construction (AFUDC) represents the cost of both the debt and equity funds used to finance utility plant additions during the construction period. In accordance with the uniform system of accounts prescribed by regulatory authorities, AFUDC is capitalized as a part of the cost of utility plant and the debt related portion is credited currently against total interest expense in the Statements of Income. The Company generally is permitted, under established regulatory rate practices, to recover the capitalized AFUDC, and a fair return thereon, through its inclusion in rate base and the provision for depreciation after the related utility plant is placed in service. Cash inflow related to AFUDC generally does not occur until the related utility plant is placed in service and included in rate base. The effective AFUDC rate was 8.22 percent in 2009 and 8.2 percent in 2008. The Company's AFUDC rates do not exceed the maximum allowable rates as determined in accordance with the requirements of regulatory authorities.

Income Taxes
A deferred income tax asset or liability is determined based on the enacted tax rates that will be in effect when the differences between the financial statement carrying amounts and tax basis of existing assets and liabilities are expected to be reported in the Company's consolidated income tax returns. The deferred income tax expense for the period is equal to the net change in the deferred income tax asset and liability accounts from the beginning to the end of the period. The effect on deferred income taxes of a change in tax rates is recognized in income in the period that includes the enactment date. Deferred income tax liabilities and regulatory assets are established for income tax benefits flowed through to customers as prescribed by the respective regulatory commissions.

Stock-Based Compensation
Compensation cost relating to share-based payment transactions is recognized in the Company's financial statements

based on the fair value of the equity or liability instruments issued. See Note 21 for further information.

Earnings per Common Share Attributable to Avista Corporation
Basic earnings per common share attributable to Avista Corporation is computed by dividing net income attributable to Avista Corporation by the weighted average number of common shares outstanding for the period. Diluted earnings per common share attributable to Avista Corporation is calculated by dividing net income attributable to Avista Corporation (adjusted for the effect of potentially dilutive securities issued by subsidiaries) by diluted weighted average common shares outstanding during the period, including common stock equivalent shares outstanding using the treasury stock method, unless such shares are anti-dilutive. Common stock equivalent shares include shares issuable upon exercise of stock options and contingent stock awards. See Note 20 for earnings per common share calculations.

Cash and Cash Equivalents
For the purposes of the Statements of Cash Flows, the Company considers all temporary investments with a maturity of three months or less when purchased to be cash equivalents. Cash and cash equivalents include cash deposits from counterparties.

Allowance for Doubtful Accounts
The Company maintains an allowance for doubtful accounts to provide for estimated and potential losses on accounts receivable. The Company determines the allowance for utility and other customer accounts receivable based on historical write-offs as compared to accounts receivable and operating revenues. Additionally, the Company establishes specific allowances for certain individual accounts. The following table presents the activity in the allowance for doubtful accounts during the years ended December 31 (dollars in thousands):

	2009	2008
Allowance as of the beginning of the year	$5,845	$2,966
Additions expensed during the year	5,160	6,336
Net deductions	(7,294)	(3,457)
Allowance as of the end of the year	$3,711	$5,845

Utility Plant in Service
The cost of additions to utility plant in service, including an allowance for funds used during construction and replacements of units of property and improvements, is capitalized. Costs of depreciable units of property retired plus costs of removal less salvage are charged to accumulated depreciation.

Regulatory Deferred Charges and Credits
The Company prepares its financial statements in accordance with the provisions of SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation" (ASC 980) because:

- rates for regulated services are established by or subject to approval by independent third-party regulators,
- the regulated rates are designed to recover the cost of providing the regulated services, and
- in view of demand for the regulated services and the level of competition, it is reasonable to assume that rates can be charged to and collected from customers at levels that will recover costs.

ASC 980 requires the Company to reflect the impact of regulatory decisions in its financial statements. ASC 980 requires that certain costs and/or obligations (such as incurred power and natural gas costs not currently included in rates, but expected to be recovered or refunded in the future) are reflected as deferred charges or credits on the Balance Sheets. These costs and/or obligations are not reflected in the Statements of Income until the period during which matching revenues are recognized.

If at some point in the future the Company determines that it no longer meets the criteria for continued application of ASC 980 for all or a portion of its regulated operations, the Company could be:

- required to write off its regulatory assets, and
- precluded from the future deferral of costs not recovered through rates at the time such costs are incurred, even if the Company expected to recover such costs in the future.

The Company's primary regulatory assets include:

- power cost deferrals,
- investment in exchange power,
- regulatory asset for deferred income taxes,

- unamortized debt repurchase costs,
- assets offsetting net utility energy commodity derivative liabilities (see Note 6 for further information),
- expenditures for demand side management programs,
- expenditures for conservation programs,
- payments to the Coeur d'Alene Tribe for past water storage and the licensing of the Spokane River Project,
- certain expenditures for licensing hydroelectric generating facilities, and
- unfunded pensions and other postretirement benefits.

Regulatory liabilities include:

- utility plant retirement costs,
- natural gas deferrals, and
- liabilities offsetting net utility energy commodity derivative assets (see Note 6 for further information).

Investment in Exchange Power-Net
The investment in exchange power represents the Company's previous investment in Washington Public Power Supply System Project 3 (WNP-3), a nuclear project that was terminated prior to completion. Under a settlement agreement with the Bonneville Power Administration in 1985, Avista Corp. began receiving power in 1987, for a 32.5-year period, related to its investment in WNP-3. Through a settlement agreement with the Washington Utilities and Transportation Commission (WUTC) in the Washington jurisdiction, Avista Corp. is amortizing the recoverable portion of its investment in WNP-3 (recorded as investment in exchange power) over a 32.5 year period beginning in 1987. For the Idaho jurisdiction, Avista Corp. fully amortized the recoverable portion of its investment in exchange power.

Unamortized Debt Expense
Unamortized debt expense includes debt issuance costs that are amortized over the life of the related debt.

Unamortized Loss on Reacquired Debt
For the Company's primary regulatory jurisdiction and for any debt repurchases beginning in 2007 in all jurisdictions, premiums paid to repurchase debt are amortized over the remaining life of the original debt that was repurchased or, if new debt is issued in connection with the repurchase, these costs are amortized over the life of the new debt. In the Company's other regulatory jurisdictions, premiums paid to repurchase debt prior to 2007 are being amortized over the average remaining maturity of outstanding debt when no new debt was issued in connection with the debt repurchase. These costs are recovered through retail rates as a component of interest expense.

NOTE 2. NEW ACCOUNTING STANDARDS

Effective January 1, 2008, the Company adopted the provisions of SFAS No. 157, "Fair Value Measurements" (ASC 820-10) related to its financial assets and liabilities and nonfinancial assets and liabilities measured at fair value on a recurring basis. In February 2008, the FASB issued Staff Position (FSP) No. 157-2, which deferred the effective date for certain portions of ASC 820-10 related to nonrecurring measurements of nonfinancial assets and liabilities. Effective January 1, 2009, the Company adopted those provisions of ASC 820-10. The adoption of the provisions of ASC 820-10 that became effective on January 1, 2008 and 2009, did not have a material impact on the Company's financial condition, results of operations and cash flows. However, the Company expanded disclosures for fair value measurements that became effective on January 1, 2008. There were no additional disclosures related to the provisions that became effective January 1, 2009. See Note 18 for the expanded disclosures.

Effective January 1, 2009, the Company adopted SFAS No. 141(R), "Business Combinations" (ASC 805-10) that replaces previous accounting guidance for business combinations and addresses the accounting for all transactions or other events in which an entity obtains control of one or more businesses. This statement requires the acquiring entity in a business combination to recognize the assets acquired, the liabilities assumed, and any noncontrolling interest in the transaction at the acquisition date, measured at their fair values as of that date, with limited exceptions.

Effective January 1, 2009, the Company adopted SFAS No. 160, "Noncontrolling Interests in Consolidated Financial Statements - an amendment of ARB No. 51" (ASC 810-10). This statement amended previous accounting guidance to establish accounting and reporting standards for a noncontrolling (minority) interest in a subsidiary and for the deconsolidation of a subsidiary. This statement clarifies that a noncontrolling interest in a subsidiary is an ownership in the consolidated entity that should be reported as equity in the consolidated financial statements. The adoption of this statement had no material impact on the Company's financial condition and results of operations.

Effective January 1, 2009, the Company adopted SFAS No. 161, "Disclosures about Derivative Instruments and Hedging Activities" (ASC 815-10) that requires disclosure of the fair value of derivative instruments and their gains and losses in a tabular format. The statement requires disclosure of derivative features that are related to credit risk. The Company expanded disclosures for derivatives and hedging activities. See Note 6 for the expanded disclosures.

Effective December 31, 2009, the Company adopted FSP FAS 132(R)-1, "Employers' Disclosures about Postretirement Benefit Plan Assets" (ASC 715-20) that amends FASB Statement No. 132(R) "Employers' Disclosures about Pensions and Other Postretirement Benefits" (ASC 715-20). This statement provides guidance on an employer's disclosures about plan assets of a defined benefit pension or other postretirement plan. The Company has expanded disclosures for its pension and other postretirement benefit plan assets in Note 9.

Effective June 30, 2009, the Company adopted FSP FAS 157-4, "Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly" (ASC 820-65-10-4) that provides guidance for determining fair values of financial instruments for which there is no active market or when quoted prices may represent distressed transactions. The guidance includes a reaffirmation of the need to use judgment in certain circumstances and requires expanded disclosures surrounding equity and debt securities. The adoption of this FSP did not have an impact on the Company's financial condition, results of operations and cash flows.

Effective June 30, 2009, the Company adopted SFAS No. 165, "Subsequent Events" (ASC 855-10). This statement established principles and requirements for subsequent events related to: 1) the period after the balance sheet date during which management of a reporting entity shall evaluate events or transactions that may occur for potential recognition or disclosure in the financial statements; 2) the circumstances under which an entity shall recognize events or transactions occurring after the balance sheet date in its financial statements; and 3) the disclosures that an entity shall make about events or transactions that occurred after the balance sheet date. The Company evaluated subsequent events up to February 26, 2010 (the date the financial statements were issued).

In June 2009, the FASB issued SFAS No. 166, "Accounting for Transfers of Financial Assets an amendment of FASB Statement No. 140" (ASC 860). This statement amends certain provisions of SFAS No. 140 (ASC 860) related to accounting for transfers of financial assets and a transferor's continuing involvement in transferred financial assets. The Company was required to adopt this statement effective January 1, 2010. The Company is evaluating the impact this statement will have on its financial condition, results of operations and cash flows. In particular, the Company is evaluating its accounts receivable sales (see Note 5) to determine whether or not the transactions meet the criteria of sales of financial assets. If the transactions did not meet the criteria, the transactions would be accounted for as secured borrowings. As of December 31, 2009, the Company had not sold any accounts receivable under the revolving agreement. The Company will finalize its evaluation during the first quarter of 2010 to determine the impact of adoption, if any, on its financial condition, results of operations and cash flows.

In June 2009, the FASB issued SFAS No. 167, "Amendments to FASB Interpretation No. 46(R)" (ASC 810). This statement carries forward the scope of FASB Interpretation No. 46(R) (ASC 810), with the addition of entities previously considered qualifying special-purpose entities, as the concept of these entities was eliminated in SFAS No. 166 (ASC 860). The amendments will significantly affect the overall consolidation analysis of variable interest entities (VIE). The amendments will require the Company to reconsider previous conclusions relating to the consolidation of VIEs, including whether an entity is a VIE, whether the Company is the VIE's primary beneficiary, and what type of financial statement disclosures are required. The Company was required to adopt this statement effective January 1, 2010. The Company is evaluating the impact this statement will have on its financial condition, results of operations and cash flows. The Company will finalize its evaluation during the first quarter of 2010 to determine the impact of adoption, if any, on its financial condition, results of operations and cash flows.

NOTE 3. DISPOSITION OF AVISTA ENERGY

On June 30, 2007, Avista Energy and Avista Energy Canada completed the sale of substantially all of their contracts and ongoing operations to Shell Energy North America (U.S.), L.P. (Shell Energy), formerly known as Coral Energy Holding, L.P., as well as to certain other subsidiaries of Shell Energy.

Certain assets of Avista Energy with a net book value of approximately $30 million were not sold or liquidated. These primarily include natural gas storage and deferred income tax assets. The Company expects that the natural gas storage will ultimately be transferred to Avista Corp., subject to future regulatory approval. There is also a power purchase agreement, related to a 270 MW natural gas-fired combined cycle combustion turbine plant located in Idaho (Lancaster Plant). The Lancaster Plant is owned by an unrelated third-party and all of the output from the plant is contracted to Avista Turbine Power, Inc. (an affiliate of Avista Energy) through 2026. The majority of the rights and obligations of the power purchase agreement were conveyed to Shell Energy through the end of 2009. The rights and obligations of power purchase agreement were conveyed to Avista Corp. in January 2010.

In connection with the transaction, on June 30, 2007, Avista Energy and its affiliates entered into an Indemnification Agreement with Shell Energy and its affiliates. Under the Indemnification Agreement, Avista Energy and Shell Energy each agree to provide indemnification of the other and the other's affiliates for certain events and matters described in the purchase and sale agreement and certain other transaction agreements. Such events and matters include, but are not limited to, the refund proceedings arising out of the western energy markets in 2000 and 2001 (see Note 22), existing litigation, tax liabilities, and matters related to natural gas storage rights. In general, such indemnification is not required unless and until a party's claims exceed $150,000 and is limited to an aggregate amount of $30 million and a term of three years (except for agreements or transactions with terms longer than three years). These limitations do not apply to certain third party claims.

Avista Energy's obligations under the Indemnification Agreement are guaranteed by Avista Capital pursuant to a Guaranty dated June 30, 2007. This Guaranty is limited to an aggregate amount of $30 million plus certain fees and expenses. The Guaranty will terminate April 30, 2011 except for claims made prior to termination. As of February 26, 2010, neither party has made any claims under the Indemnification Agreement or Guaranty.

NOTE 4. ADVANTAGE IQ ACQUISITIONS

Effective July 2, 2008, Advantage IQ completed the acquisition of Cadence Network, a privately held, Cincinnati-based energy and expense management company. As consideration, the owners of Cadence Network received a 25 percent ownership interest in Advantage IQ. The total value of the transaction was $37 million.

The acquisition of Cadence Network was funded with the issuance of Advantage IQ common stock. Under the transaction agreement, the previous owners of Cadence Network can exercise a right to have their shares of Advantage IQ common stock redeemed during July 2011 or July 2012 if Advantage IQ is not liquidated through either an initial public offering or sale of the business to a third party. Their redemption rights expire July 31, 2012. The redemption price would be determined based on the fair market value of Advantage IQ at the time of the redemption election as determined by certain independent parties.

On August 31, 2009, Advantage IQ acquired substantially all of the assets and liabilities of Ecos Consulting, Inc. (Ecos), a Portland, Oregon-based energy efficiency solutions provider for $8.9 million. Under the terms of the transaction, the assets and liabilities of Ecos were acquired by a wholly owned subsidiary of Advantage IQ.

NOTE 5. ACCOUNTS RECEIVABLE SALE

Avista Receivables Corporation (ARC) is a wholly owned, bankruptcy-remote subsidiary of Avista Corp. formed for the purpose of acquiring or purchasing interests in certain accounts receivable, both billed and unbilled, of the Company. Avista Corp., ARC and a third-party financial institution are parties to a Receivables Purchase Agreement, and on March 13, 2009 that agreement was amended to, among other things, extend the termination date to March 12, 2010. Under the Receivables Purchase Agreement, ARC can sell without recourse, and such financial institution will purchase, on a revolving basis, up to $85.0 million of those receivables. ARC is obligated to pay fees that approximate the purchaser's cost of issuing commercial paper equal in value to the interests in receivables sold. The amount of such fees is included in other operating expenses of Avista Corp. The Receivables Purchase Agreement has financial covenants, which are substantially the same as those of Avista Corp.'s committed lines of credit (see Note 12). Based on calculations of eligible receivables, ARC had the ability to sell up to $85.0 million of receivables under this revolving agreement at each of December 31, 2009 and December 31, 2008. There were not any accounts receivable sold under this revolving agreement as of December 31, 2009 and $17.0 million were sold as of December 31, 2008.

NOTE 6. DERIVATIVES AND RISK MANAGEMENT

Energy Commodity Derivatives

Avista Corp. is exposed to market risks relating to changes in electricity and natural gas commodity prices and certain other fuel prices. Market risk is, in general, the risk of fluctuation in the market price of the commodity being traded and is influenced primarily by supply and demand. Market risk includes the fluctuation in the market price of associated derivative commodity instruments. Market risk may also be influenced by market participants' nonperformance of their contractual obligations and commitments, which affects the supply of, or demand for, the commodity. Avista Corp. utilizes derivative instruments, such as forwards, futures, swaps and options in order to manage the various risks relating to these commodity price exposures. The Company has an energy resources risk policy and control procedures to manage these risks. The Company's Risk Management Committee establishes the

Company's energy resources risk policy and monitors compliance. The Risk Management Committee is comprised of certain Company officers and other management. The Audit Committee of the Company's Board of Directors periodically reviews and discusses risk assessment and risk management policies, including the Company's material financial and accounting risk exposures and the steps management has undertaken to control them.

As part of its resource procurement and management operations in the electric business, Avista Corp. engages in an ongoing process of resource optimization, which involves the economic selection from available energy resources to serve Avista Corp.'s load obligations and the use of these resources to capture available economic value. Avista Corp. sells and purchases wholesale electric capacity and energy and fuel as part of the process of acquiring and balancing resources to serve its load obligations. These transactions range from terms of one hour up to multiple years. Avista Corp. makes continuing projections of:

- electric loads at various points in time (ranging from one hour to multiple years) based on, among other things, estimates of customer usage and weather, historical data and contract terms, and
- resource availability at these points in time based on, among other things, fuel choices and fuel markets, estimates of streamflows, availability of generating units, historic and forward market information, contract terms, and experience.

On the basis of these projections, Avista Corp. makes purchases and sales of electric capacity and energy and fuel to match expected resources to expected electric load requirements. Resource optimization involves generating plant dispatch and scheduling available resources and also includes transactions such as:

- purchasing fuel for generation,
- when economical, selling fuel and substituting wholesale electric purchases, and
- other wholesale transactions to capture the value of generation and transmission resources.

Avista Corp.'s optimization process includes entering into hedging transactions to manage risks.

As part of its resource procurement and management operations in the natural gas business, Avista Corp. makes continuing projections of its natural gas loads and assesses available natural gas resources. Forward natural gas contracts are typically for monthly delivery periods. However, daily variations in natural gas demand can be significantly different than monthly demand projections. On the basis of these projections, Avista Corp. plans and executes a series of transactions to hedge a significant portion of its projected natural gas requirements through forward market transactions and derivative instruments. These transactions may extend as much as four natural gas operating years (November through October) into the future. Avista Corp. also leaves a significant portion of its gas supply requirements unhedged for purchase in short-term and spot markets. Natural gas resource optimization activities include:

- wholesale market sales of surplus gas supplies,
- purchases and sales of natural gas to use underutilized pipeline capacity, and
- sales of excess natural gas storage capacity.

Derivatives are recorded as either assets or liabilities on the balance sheet measured at estimated fair value. In certain defined conditions, a derivative may be specifically designated as a hedge for a particular exposure. The accounting for derivatives depends on the intended use of the derivatives and the resulting designation.

The WUTC and the IPUC issued accounting orders authorizing Avista Corp. to offset commodity derivative assets or liabilities with a regulatory asset or liability. This accounting treatment is intended to defer the recognition of mark-to-market gains and losses on energy commodity transactions until the period of settlement. The orders provide for Avista Corp. to not recognize the unrealized gain or loss on utility derivative commodity instruments in the Statements of Income. Realized gains or losses are recognized in the period of settlement, subject to approval for recovery through retail rates. Realized gains and losses, subject to regulatory approval, result in adjustments to retail rates through purchased gas cost adjustments, the Energy Recovery Mechanism (ERM) in Washington, the Power Cost Adjustment (PCA) mechanism in Idaho, and periodic general rates cases.

Substantially all forward contracts to purchase or sell power and natural gas are recorded as assets or liabilities at market value with an offsetting regulatory asset or liability. Contracts that are not considered derivatives under ASC 815 are generally accounted for on the accrual basis until they are settled or realized, unless there is a decline in the fair value of the contract that is determined to be other than temporary.

The following table presents the underlying energy commodity derivative volumes as of December 31, 2009 that are expected to settle in each respective year (in thousands of MWhs and mmBTUs):

	Purchases				Sales			
	Electric Derivatives		Gas Derivatives		Electric Derivatives		Gas Derivatives	
Year	Physical MWH	Financial MWH	Physical mmBTUs	Financial mmBTUs	Physical MWH	Financial MWH	Physical mmBTUs	Financial mmBTUs
2010	760	568	26,699	1,210	1,381	49	5,051	-
2011	401	138	10,477	-	286	31	467	-
2012	366	-	4,128	-	287	-	-	-
2013	368	-	1,575	-	286	-	-	-
2014	366	-	-	-	286	-	-	-
Thereafter	1,694	-	-	-	1,303	-	-	-

Foreign Currency Exchange Contracts
A significant portion of Avista Corp.'s natural gas supply (including fuel for power generation) is obtained from Canadian sources. Most of those transactions are executed in U.S. dollars, which avoids foreign currency risk. A portion of Avista Corp.'s short-term natural gas transactions and long-term Canadian transportation contracts are committed based on Canadian currency prices and settled within sixty days with U.S. dollars. In early 2009, Avista Corp. implemented a process to economically hedge a portion of the foreign currency risk by purchasing Canadian currency when such commodity transactions are initiated. This risk has not had a material effect on the Company's financial condition, results of operations or cash flows and these differences in cost related to currency fluctuations were included with natural gas supply costs for ratemaking. As of December 31, 2009, the Company had a current derivative liability for foreign currency hedges of less than $0.1 million. As of December 31, 2009, the Company had entered into 24 Canadian currency forward contracts with a notional amount of $10.2 million ($10.6 million Canadian).

Interest Rate Swap Agreements
Avista Corp. enters into forward-starting interest rate swap agreements to manage the risk associated with changes in interest rates and the impact on future interest payments. These interest rate swap agreements relate to the interest payments for anticipated debt issuances. These interest rate swap agreements are considered economic hedges against fluctuations in future cash flows associated with changes in interest rates. In September 2009, the Company cash settled interest rate swap contracts (notional amount of $200.0 million) and received a total of $10.8 million. The interest rate swap contracts were settled concurrently with the issuance of $250.0 million of First Mortgage Bonds (see Note 13). These settlements of the interest rate swaps were deferred as a regulatory liability (included as part of long-term debt) and will be amortized as a component of interest expense over the life of the associated debt issued in accordance with regulatory accounting practices. The Company did not have any interest rate swap contracts outstanding as of December 31, 2009.

Derivative Instruments Summary
The following table presents the fair values and locations of derivative instruments recorded on the Balance Sheet as of December 31, 2009 (in thousands):

		Fair Value		
Derivative	Balance Sheet Location	Asset	Liability	Net Asset (Liability)
Foreign currency contracts	Derivative instrument liabilities hedges	$ -	$ (50)	$ (50)
Commodity contracts	Derivative instrument assets current	8,976	(1,219)	7,757
Commodity contracts	Long-term derivative instrument assets	53,765	(8,282)	45,483
Commodity contracts	Derivative instrument liabilities current	5,783	(21,870)	(16,087)
Commodity contracts	Long-term derivative instrument liabilities	650	(3,521)	(2,871)
Total derivative instruments recorded on the balance sheet		$69,174	$(34,942)	$34,232

Exposure to Demands for Collateral
The Company's derivative contracts often require collateral (in the form of cash or letters of credit) or other credit enhancements, or reductions or terminations of a portion of the contract through cash settlement, in the event of a

downgrade in the Company's credit ratings or adverse changes in market prices. In periods of price volatility, the level of exposure can change significantly. As a result, sudden and significant demands may be made against the Company's credit facilities and cash. The Company actively monitors the exposure to possible collateral calls and takes steps to minimize capital requirements.

Certain of the Company's derivative instruments contain provisions that require the Company to maintain an investment grade credit rating from the major credit rating agencies. If the Company's credit ratings were to fall below investment grade, it would be in violation of these provisions, and the counterparties to the derivative instruments could request immediate payment or demand immediate and ongoing collateralization on derivative instruments in net liability positions. The aggregate fair value of all derivative instruments with credit-risk-related contingent features that are in a liability position as of December 31, 2009 was $11.8 million. If the credit-risk-related contingent features underlying these agreements were triggered on December 31, 2009, the Company would be required to post $3.4 million of collateral to its counterparties.

Credit Risk

Credit risk relates to the potential losses that the Company would incur as a result of non-performance by counterparties of their contractual obligations to deliver energy or make financial settlements. The Company often extends credit to counterparties and customers and is exposed to the risk that it may not be able to collect amounts owed to the Company. Changes in market prices may dramatically alter the size of credit risk with counterparties, even when conservative credit limits are established.

Credit risk includes potential counterparty default due to circumstances:

- relating directly to it,
- caused by market price changes, and
- relating to other market participants that have a direct or indirect relationship with snch counterparty.

Should a counterparty, customer or supplier fail to perform, the Company may be required to honor the underlying commitment or to replace existing contracts with contracts at then-current market prices. The Company seeks to mitigate credit risk by:

- entering into bilateral contracts that specify credit terms and protections against default,
- applying credit limits and duration criteria to existing and prospective counterparties,
- actively monitoring current credit exposures, and
- conducting some of its transactions on exchanges with clearing arrangements that essentially eliminate counterparty default risk.

These credit policies include an evaluation of the financial condition and credit ratings of counterparties, collateral requirements or other credit enhancements, such as letters of credit or parent company guarantees. The Company also uses standardized agreements that allow for the netting or offsetting of positive and negative exposures associated with a single counterparty or affiliated group.

The Company has concentrations of suppliers and customers in the electric and natural gas industries including:

- electric utilities,
- electric generators and transmission providers,
- natural gas producers and pipelines,
- financial institutions, and
- energy marketing and trading companies.

In addition, the Company has concentrations of credit risk related to geographic location as it operates in the western United States and western Canada. These concentrations of counterparties and concentrations of geographic location may impact the Company's overall exposure to credit risk, either positively or negatively, because the counterparties may be similarly affected by changes in conditions.

As is common industry practice, Avista Corp. maintains margin agreements with certain counterparties. Margin calls are triggered when exposures exceed predetermined contractual limits or when there are changes in a counterparty's creditworthiness. Price movements in electricity and natural gas can generate exposure levels in excess of these contractual limits. Margin calls are periodically made and/or received by Avista Corp. Negotiating for collateral in the form of cash, letters of credit, or performance guarantees is common industry practice.

Cash deposits from counterparties totaled $3.2 million as of December 31, 2009 and $0.2 million as of December 31,

2008. These funds were held by Avista Corp. to mitigate the potential impact of counterparty default risk. These amounts are subject to return if conditions warrant because of continuing portfolio value fluctuations with those parties or substitution of non-cash collateral.

NOTE 7. JOINTLY OWNED ELECTRIC FACILITIES

The Company has a 15 percent ownership interest in a twin-unit coal-fired generating facility, the Colstrip Generating Project (Colstrip) located in southeastern Montana, and provides financing for its ownership interest in the project. The Company's share of related fuel costs as well as operating expenses for plant in service are included in the corresponding accounts in the Statements of Income. The Company's share of utility plant in service for Colstrip was $334.8 million and accumulated depreciation was $209.6 million as of December 31, 2009. The Company's share of utility plant in service for Colstrip was $330.9 million and accumulated depreciation was $204.0 million as of December 31, 2008.

NOTE 8. ASSET RETIREMENT OBLIGATIONS

The Company records the fair value of a liability for an asset retirement obligation in the period in which it is incurred. When the liability is initially recorded, the associated costs of the asset retirement obligation are capitalized as part of the carrying amount of the related long-lived asset. The liability is accreted to its present value each period and the related capitalized costs are depreciated over the useful life of the related asset. Upon retirement of the asset, the Company either settles the retirement obligation for its recorded amount or incurs a gain or loss. The Company records regulatory assets and liabilities for the difference between asset retirement costs currently recovered in rates and asset retirement obligations recorded since asset retirement costs are recovered through rates charged to customers. The regulatory assets do not earn a return.

Specifically, the Company has recorded liabilities for future asset retirement obligations to:

- restore ponds at Colstrip,
- cap a landfill at the Kettle Falls Plant,
- remove plant and restore the land at the Coyote Springs 2 site at the termination of the land lease,
- remove asbestos at the corporate office building, and
- dispose of PCBs in certain transformers.

Due to an inability to estimate a range of settlement dates, the Company cannot estimate a liability for the:

- removal and disposal of certain transmission and distribution assets, and
- abandonment and decommissioning of certain hydroelectric generation and natural gas storage facilities.

The following table documents the changes in the Company's asset retirement obligation during the years ended December 31 (dollars in thousands):

	2009	2008
Asset retirement obligation at beginning of year	$4,208	$3,990
New liability recognized	-	-
Liability adjustment due to revision in estimated cash flows	-	-
Liability settled	(499)	(29)
Accretion expense	262	247
Asset retirement obligation at end of year	$3,971	$4,208

NOTE 9. PENSION PLANS AND OTHER POSTRETIREMENT BENEFIT PLANS

The Company has a defined benefit pension plan covering substantially all regular full-time employees. Individual benefits under this plan are based upon the employee's years of service and average compensation as specified in the plan. The Company's funding policy is to contribute at least the minimum amounts that are required to be funded under the Employee Retirement Income Security Act, but not more than the maximum amounts that are currently deductible for income tax purposes. The Company contributed $48 million in cash to the pension plan in 2009 and $28 million in 2008. The Company expects to contribute $21 million to the pension plan in 2010.

The Company also has a Supplemental Executive Retirement Plan (SERP) that provides additional pension benefits to executive officers of the Company. The SERP is intended to provide benefits to executive officers whose benefits under the pension plan are reduced due to the application of Section 415 of the Internal Revenue Code of 1986 and the deferral of salary under deferred compensation plans. The liability and expense for this plan are included as pension benefits in the tables included in this Note.

The Company expects that benefit payments under the pension plan and the SERP will total $18.6 million in 2010, $19.4 million in 2011, $20.5 million in 2012, $21.7 million in 2013 and $23.0 million in 2014. For the ensuing five years (2015 through 2019), the Company expects that benefit payments under the pension plan and the SERP will total $136.3 million.

The expected long-term rate of return on plan assets is based on past performance and economic forecasts for the types of investments held by the plan. In selecting a discount rate, the Company considers yield rates for highly rated corporate bond portfolios with maturities similar to that of the expected term of pension benefits.

In 2009, the Company reviewed the mortality table utilized in the actuarial calculations. The Company determined that the RP-2000 combined healthy mortality tables for males and females should be replaced with the RP-2000 combined healthy mortality tables for males and females projected to 2010 using scale AA. The change resulted in an increase of $6.6 million to the pension benefit obligation as of December 31, 2009.

In 2008, the rates at which participants are assumed to retire by age were analyzed based upon historical trends and future projections. The Company revised the rates to assume that a greater percentage of participants would retire between the ages of 55 and 65. The assumed rates were revised to range from 5 percent to 40 percent and 100 percent at age 65. The previous rates ranged from 2 percent to 30 percent and 100 percent at age 65. The change resulted in an increase of $11.0 million to the pension benefit obligation as of December 31, 2008.

The Company provides certain health care and life insurance benefits for substantially all of its retired employees. The Company accrues the estimated cost of postretirement benefit obligations during the years that employees provide services. The Company elected to amortize the transition obligation of $34.5 million over a period of twenty years, beginning in 1993.

The Company established a Health Reimbursement Arrangement to provide employees with tax-advantaged funds to pay for allowable medical expenses upon retirement. The amount earned by the employee is fixed on the retirement date based on employees' years of service and the ending salary. The liability and expense of this plan are included as other postretirement benefits.

The Company provides death benefits to beneficiaries of executive officers who die during their term of office or after retirement. Under the plan, an executive officer's designated beneficiary will receive a payment equal to twice the executive officer's annual base salary at the time of death (or if death occurs after retirement, a payment equal to twice the executive officer's total annual pension benefit). The liability and expense for this plan are included as other postretirement benefits.

The Company expects that benefit payments under other postretirement benefit plans will be $4.1 million in 2010, $3.9 million in 2011, $3.7 million in 2012, $3.6 million in 2013 and $3.5 million in 2014. For the ensuing five years (2015 through 2019), the Company expects that benefit payments under other postretirement benefit plans will total $16.4 million. The Company expects to contribute $4.1 million to other postretirement benefit plans in 2010, representing expected benefit payments to be paid during the year.

The Company uses a December 31 measurement date for its pension and other postretirement benefit plans. The following table sets forth the pension and other postretirement benefit plan disclosures as of December 31, 2009 and 2008 and the components of net periodic benefit costs for the years ended December 31, 2009 and 2008 (dollars in thousands):

	Pension Benefits		Other Post-retirement Benefits	
	2009	2008	2009	2008
Change in benefit obligation:				
Benefit obligation as of beginning of year	$353,572	$323,090	$38,953	$34,352
Service cost	10,496	10,209	803	772
Interest cost	21,770	20,812	2,364	2,371
Actuarial loss	9,610	17,041	1,676	5,611
Transfer of accrued vacation	-	-	98	365
Benefits paid	(17,213)	(17,580)	(4,334)	(4,518)
Benefit obligation as of end of year	$378,235	$353,572	$39,560	$38,953

Change in plan assets:				
Fair value of plan assets as of beginning of year	$190,637	$242,561	$16,048	$22,718
Actual return on plan assets	50,053	(63,575)	4,346	(6,670)
Employer contributions	48,000	28,000	-	-
Benefits paid	(15,958)	(16,349)	-	-
Fair value of plan assets as of end of year	$272,732	$190,637	$20,394	$16,048
Funded status	$(105,503)	$(162,935)	$(19,166)	$(22,905)
Unrecognized net actuarial loss	126,926	160,280	15,772	18,357
Unrecognized prior service cost	1,790	2,444	(1,303)	(1,452)
Unrecognized net transition obligation	-	-	1,516	2,021
Prepaid (accrued) benefit cost	23,213	(211)	(3,181)	(3,979)
Additional liability	(128,716)	(162,724)	(15,985)	(18,926)
Accrued benefit liability	$(105,503)	$(162,935)	$(19,166)	$(22,905)
Accumulated pension benefit obligation	$294,649	$307,413	-	-
Accumulated postretirement benefit obligation:				
For retirees			$18,377	$18,821
For fully eligible employees			$9,290	$8,903
For other participants			$11,893	$11,229
Included in accumulated comprehensive loss (income) (net of tax):				
Unrecognized net transition obligation	$ -	$ -	$ 985	$1,313
Unrecognized prior service cost	1,163	1,589	(847)	(943)
Unrecognized net actuarial loss	82,502	104,182	10,252	11,932
Total	83,665	105,771	10,390	12,302
Less regulatory asset	(80,041)	(98,850)	(11,664)	(13,131)
Accumulated other comprehensive loss (income)	$3,624	$6,921	$(1,274)	$ (829)
Weighted average assumptions as of December 31:				
Discount rate for benefit obligation	6.29%	6.25%	6.00%	6.25%
Discount rate for annual expense	6.25%	6.34%	6.25%	6.20%
Expected long-term return on plan assets	8.50%	8.50%	8.50%	8.50%
Rate of compensation increase	4.65%	4.72%		
Medical cost trend pre-age 65 – initial			8.50%	9.00%
Medical cost trend pre-age 65 – ultimate			5.00%	5.00%
Ultimate medical cost trend year pre-age 65			2017	2017
Medical cost trend post-age 65 – initial			8.50%	9.00%
Medical cost trend post-age 65 – ultimate			6.00%	6.00%
Ultimate medical cost trend year post-age 65			2015	2015
Components of net periodic benefit cost:				
Service cost	$10,496	$10,209	$ 803	$ 772
Interest cost	21,770	20,812	2,364	2,371
Expected return on plan assets	(17,612)	(21,138)	(1,364)	(1,931)
Transition obligation recognition	-	-	505	505
Amortization of prior service cost	654	654	(149)	(149)
Net loss recognition	10,539	3,345	1,279	575
Net periodic benefit cost	$25,847	$13,882	$3,438	$2,143

Plan Assets

The Finance Committee of the Company's Board of Directors:

- establishes investment policies, objectives and strategies that seek an appropriate return for the pension plan and other postretirement plan, and
- reviews and approves changes to the investment and funding policies.

The Company has contracted with investment consultants who are responsible for managing/monitoring the individual investment managers. The investment managers' performance and related individual fund performance is periodically reviewed by an internal benefits committee and by the Finance Committee to monitor compliance with investment policy objectives and strategies.

Pension plan assets are invested primarily in marketable debt and equity securities. Pension plan assets may also be invested in real estate, absolute return, venture capital/private equity and commodity funds. In seeking to obtain the desired return to fund the pension plan, the investment consultant recommends allocation percentages by asset classes. These recommendations are reviewed by the internal benefits committee, which then recommends their adoption by the Finance Committee. The Finance Committee has established target investment allocation percentages by asset classes as of December 31, 2009 and 2008 as indicated in the table below:

	2009	2008
Equity securities	51%	50%
Debt securities	31%	30%
Real estate	5%	5%
Absolute return	10%	12%
Other	3%	3%

The market-related value of pension plan assets invested in debt and equity securities was based primarily on fair value (market prices). The fair value of investment securities traded on a national securities exchange is determined based on the last reported sales price; securities traded in the over-the-counter market are valued at the last reported bid price. Investment securities for which market prices are not readily available or for which market prices do not represent the value at the time of pricing, are fair-valued by the investment manager based upon other inputs (including valuations of securities that are comparable in coupon, rating, maturity and industry). Investments in common/collective trust funds are presented at estimated fair value, which is determined based on the unit value of the fund. Unit value is determined by an independent trustee, which sponsors the fund, by dividing the fund's net assets by its units outstanding at the valuation date. The fair value of the closely held investments and partnership interests is based upon the allocated share of the fair value of the underlying assets as well as the allocated share of the undistributed profits and losses, including realized and unrealized gains and losses.
The market-related value of pension plan assets invested in real estate was determined by the investment manager based on three basic approaches:

- current cost of reproducing a property less deterioration and functional economic obsolescence,
- capitalization of the property's net earnings power, and
- value indicated by recent sales of comparable properties in the market.

The market-related value of pension plan assets was determined as of December 31, 2009 and 2008.

The following table discloses by level within the fair value hierarchy (refer to Note 18 for a description of the fair value hierarchy) of the pension plan's assets measured and reported as of December 31, 2009 at fair value (dollars in thousands):

	Level 1	Level 2	Level 3	Total
Cash equivalents	$ 19	$ -	$ -	$ 19
Mutual funds:				
Fixed income securities	70,924	-	-	70,924
U.S. equity securities	87,562	-	-	87,562
International equity securities	46,548	-	-	46,548
Absolute return (1)	11,671	-	-	11,671
Commodities (2)	5,870	-	-	5,870
Common/collective trusts:				
Fixed income securities	-	14,840	-	14,840
U.S. equity securities	-	11,070	-	11,070
Absolute return (1)	-	-	844	844
Real estate	-	-	6,029	6,029
Partnership/closely held investments:				
Absolute return (1)	-	-	15,794	15,794
Private equity funds (3)	-	-	1,561	1,561
Total	$222,594	$25,910	$24,228	$272,732

(1) This category invests in multiple strategies to diversify risk and reduce volatility. The strategies include: (a) event driven, relative value, convertible, and fixed income arbitrage, (b) distressed investments, (c) long/short equity and fixed income and (d) market neutral strategies.
(2) The fund primarily invests in derivatives linked to commodity indices to gain exposure to the commodity markets. The fund manager fully collateralizes these positions with debt securities.
(3) This category includes several private equity funds that invest primarily in U.S. companies.

The table below discloses the summary of changes in the fair value of the pension plan's Level 3 assets for the year ended December 31, 2009 (dollars in thousands):

	Common/collective trusts		Partnership/closely held investments	
	Absolute return	Real estate	Absolute return	Private equity funds
Balance, as of January 1, 2009	$2,351	$11,987	$ 13,983	$1,316
Realized gains (losses)	(415)	520	-	3
Unrealized gains (losses)	(21)	(4,310)	1,811	223
Purchases (sales), net	(1,071)	(2,168)	-	19
Balance, as of December 31, 2009	$ 844	$ 6,029	$15,794	$1,561

The market-related value of other postretirement plan assets invested in debt and equity securities was based primarily on fair value (market prices). The fair value of investment securities traded on a national securities exchange is determined based on the last reported sales price; securities traded in the over-the-counter market are valued at the last reported bid price. Investment securities for which market prices are not readily available or for which market prices do not represent the value at the time of pricing, are fair-valued by the investment manager based upon other inputs (including valuations of securities that are comparable in coupon, rating, maturity and industry).

The market-related value of other postretirement plan assets was determined as of December 31, 2009 and 2008.

The following table discloses by level within the fair value hierarchy (refer to Note 18 for a description of the fair value hierarchy) of other postretirement plan assets measured and reported as of December 31, 2009 at fair value (dollars in thousands):

	Level 1	Level 2	Level 3	Total
Cash equivalents	$ 96	$ -	$ -	$ 96
Mutual funds:				
Debt securities	7,742	-	-	7,742
U.S. equity securities	5,927	-	-	5,927
International equity securities	5,077	-	-	5,077
Debt securities	25	-	-	25
U.S. equity securities	1,456	-	-	1,456
International equity securities	71	-	-	71
Total	$20,394	$ -	$ -	$20,394

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A one-percentage-point increase in the assumed health care cost trend rate for each year would increase the accumulated postretirement benefit obligation as of December 31, 2009 by $2.1 million and the service and interest cost by $0.2 million. A one-percentage-point decrease in the assumed health care cost trend rate for each year would decrease the accumulated postretirement benefit obligation as of December 31, 2009 by $1.9 million and the service and interest cost by $0.2 million.

The Company and its most significant subsidiaries have salary deferral 401(k) plans that are defined contribution plans and cover substantially all employees. Employees can make contributions to their respective accounts in the plans on a pre-tax basis up to the maximum amount permitted by law. The respective company matches a portion of the salary deferred by each participant according to the schedule in the respective plan. Employer matching contributions were $4.4 million in 2009 and $4.3 million in 2008.

The Company has an Executive Deferral Plan. This plan allows executive officers and other key employees the opportunity to defer until the earlier of their retirement, termination, disability or death, up to 75 percent of their base salary and/or up to 100 percent of their incentive payments. Deferred compensation funds are held by the Company in a Rabbi Trust. At December 31, 2009 and 2008, there were deferred compensation assets of $9.4 million and $8.8 million included in other special funds and corresponding deferred compensation liabilities of $9.4 million and $8.8 million included in other deferred credits on the Balance Sheets.

NOTE 10. ACCOUNTING FOR INCOME TAXES

Deferred income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes and tax credit carryforwards.

As of December 31, 2009, the Company had $11.6 million of state tax credit carryforwards. State tax credits expire from 2015 to 2021. The Company recognizes the effect of state tax credits generated from utility plant as they are utilized.

The realization of deferred income tax assets is dependent upon the ability to generate taxable income in future periods. The Company evaluated available evidence supporting the realization of its deferred income tax assets and determined it is more likely than not that deferred income tax assets will be realized.

The Company and its eligible subsidiaries file consolidated federal income tax returns. The Company also files state income tax returns in certain jurisdictions, including Idaho, Oregon and Montana. Subsidiaries are charged or credited with the tax effects of their operations on a stand-alone basis. The Internal Revenue Service (IRS) has completed its examination of all tax years through 2007 and all issues were resolved related to these years. The IRS has not examined the Company's 2008 federal income tax return. This examination could result in a change in the liability for uncertain tax positions. However, an estimate of the range of any such possible change cannot be made at this time. The Company does not believe that any open tax years for state income taxes could result in any adjustments that would be significant to the financial statements.

In August 2005, the Treasury Department issued regulations and the IRS issued a revenue ruling that affects the tax treatment by Avista Corp. of certain indirect overhead expenses. Avista Corp. had previously made a tax election to currently deduct certain indirect overhead costs, starting with the 2002 tax return, that were capitalized for financial accounting purposes. This election allowed Avista Corp. to take tax deductions resulting in a total reduction of approximately $40 million in current tax liabilities for 2002, 2003 and 2004. These current tax benefits were deferred on the balance sheet and did not affect net income.

On the basis of the revenue ruling and related regulations, the IRS disallowed the tax deduction of indirect overhead expenses during their examination of the Company's 2001, 2002 and 2003 federal income tax returns. The Company believed that the tax deductions claimed on tax returns were appropriate based on the applicable statutes and regulations in effect at the time. Avista Corp. appealed the proposed IRS adjustment in April 2006. The Company repaid a portion of the previous tax deductions through tax payments in 2005, 2006 and 2008.

On September 10, 2008, the Company entered into a Settlement Agreement with the Appeals Division of the IRS that resolved all items noted during their audit of the Company's 2001 through 2003 tax years, including, among other things, indirect overhead expenses. The agreement was reviewed and approved by the Joint Committee on Taxation, and a settlement payment was received in December 2008. The original IRS disallowance and the Company's appeal of the indirect overhead issue caused a delay in associated tax refunds for net operating losses that were carried back to several earlier years. The final settlement with the IRS freed up the refund years and set the amount owed for the 2001-2003 tax years. The net result was a refund to the Company of $14.7 million, plus interest of $5.7 million.

The Company had net regulatory assets of $97.9 million at December 31, 2009 and $115.0 million at December 31, 2008 related to the probable recovery of certain deferred income tax liabilities from customers through future rates.

NOTE 11. ENERGY PURCHASE CONTRACTS

Avista Corp. has contracts for the purchase of fuel for thermal generation, natural gas for resale and various agreements for the purchase or exchange of electric energy with other entities. The termination dates of the contracts range from one month to the year 2055. Total expenses for power purchased, natural gas purchased, fuel for generation and other fuel costs, which are included in operation expenses in the Statements of Income, were $704.9 million in 2009 and $951.4 million in 2008. The following table details Avista Corp.'s future contractual commitments for power resources (including transmission contracts) and natural gas resources (including transportation contracts) (dollars in thousands):

	2010	2011	2012	2013	2014	Thereafter	Total
Power resources	$220,286	$133,287	$104,716	$ 79,543	$70,605	$485,980	$1,094,417
Natural gas resources	146,321	93,609	62,084	44,375	44,424	431,904	822,717
Total	$366,607	$226,896	$166,800	$123,918	$115,029	$917,884	$1,917,134

These energy purchase contracts were entered into as part of Avista Corp.'s obligation to serve its retail electric and natural gas customers' energy requirements. As a result, these costs are generally recovered either through base retail rates or adjustments to retail rates as part of the power and natural gas cost deferral and recovery mechanisms.

In addition, Avista Corp. has operational agreements, settlements and other contractual obligations for its generation, transmission and distribution facilities. The expenses associated with these agreements are reflected as operation expenses and maintenance expenses in the Statements of Income. The following table details future contractual commitments for these agreements (dollars in thousands):

	2010	2011	2012	2013	2014	Thereafter	Total
Contractual obligations.....	$46,773	$55,084	$48,457	$52,181	$53,211	$573,643	$829,349

Avista Corp. has fixed contracts with certain Public Utility Districts (PUD) to purchase portions of the output of certain generating facilities. Although Avista Corp. has no investment in the PUD generating facilities, the fixed contracts obligate Avista Corp. to pay certain minimum amounts (based in part on the debt service requirements of the PUD) whether or not the facilities are operating. The cost of power obtained under the contracts, including payments made when a facility is not operating, is included in operation expenses in the Statements of Income. Expenses under these PUD contracts were $12.6 million in 2009 and $14.9 million in 2008. Information as of December 31, 2009 pertaining to these PUD contracts is summarized in the following table (dollars in thousands):

	Company's Current Share of					
	Output	Kilowatt Capability	Annual Costs (1)	Debt Service Costs (1)	Bonds Outstanding	Expiration Date
Chelan County PUD:						
Rocky Reach Project	2.9%	37,000	$ 1,658	$883	$ 909	2011
Douglas County PUD:						
Wells Project	3.5%	30,000	1,609	698	3,728	2018
Grant County PUD:						
Priest Rapids Project	3.3%	31,500	4,377	726	7,854	2055
Wanapum Project (2)	7.4%	76,800	4,989	2,394	13,554	2055
Totals..........................		175,300	$12,633	$4,701	$26,045	

(1) The annual costs will change in proportion to the percentage of output allocated to Avista Corp. in a particular year. Amounts represent the operating costs for the year 2009. Debt service costs are included in annual costs.
(2) A previous contract expired on October 31, 2009. A new contract was completed in 2001 with an expiration date of 2055. Beginning in November 2009, the Company's rights to the output were reduced from 8.2 percent to 3.3 percent. Under the new contract the Company has the rights to the output but not the obligation to take the output. In September of each year the Company is required to determine if it will take the output for the subsequent year.

The estimated aggregate amounts of required minimum payments (Avista Corp.'s share of existing debt service costs) under these PUD contracts are as follows (dollars in thousands):

	2010	2011	2012	2013	2014	Thereafter	Total
Minimum payments	$2,985	$2,926	$2,500	$2,496	$2,368	$30,777	$44,052

In addition, Avista Corp. will be required to pay its proportionate share of the variable operating expenses of these projects.

NOTE 12. NOTES PAYABLE

Avista Corp. has a committed line of credit agreement with various banks in the total amount of $320.0 million with an expiration date of April 5, 2011. Under the credit agreement, the Company can borrow or request the issuance of letters of credit in any combination up to $320.0 million. Total letters of credit outstanding were $28.4 million as of December 31, 2009 and $24.3 million as of December 31, 2008. The committed line of credit is secured by $320.0 million of non-transferable First Mortgage Bonds of the Company issued to the agent bank that would only become due and payable in the event, and then only to the extent, that the Company defaults on its obligations under the committed line of credit.

Additionally, the Company has a committed line of credit agreement with various banks in the total amount of $75.0 million with an expiration date of April 5, 2011. Avista Corp. may elect to increase the committed line of credit by up to $25.0 million under the same agreement. The committed line of credit is secured by $75.0 million of non-transferable First Mortgage Bonds of the Company issued to the agent bank that would only become due and payable in the event, and then only to the extent, that the Company defaults on its obligations under the committed line of credit.

The committed line of credit agreements contain customary covenants and default provisions, including a covenant requiring the ratio of "earnings before interest, taxes, depreciation and amortization" to "interest expense" of Avista Corp. for the preceding twelve-month period at the end of any fiscal quarter to be greater than 1.6 to 1. As of December 31, 2009, the Company was in compliance with this covenant with a ratio of 4.23 to 1. The committed line of credit agreements also have a covenant which does not permit the ratio of "consolidated total debt" to "consolidated total capitalization" of Avista Corp. to be greater than 70 percent at any time. As of December 31, 2009, the Company was in compliance with this covenant with a ratio of 53.6 percent.

Balances outstanding and interest rates of borrowings (excluding letters of credit) under the Company's revolving committed lines of credit were as follows as of and for the years ended December 31 (dollars in thousands):

	2009	2008
Balance outstanding at end of period	$ 87,000	$250,000
Maximum balance outstanding during the period	$275,000	$250,000
Average balance outstanding during the period	$186,474	$ 48,426
Average interest rate during the period	0.65%	3.04%
Average interest rate at end of period	0.59%	0.81%

NOTE 13. BONDS

The following details bonds outstanding as of December 31 (dollars in thousands):

Maturity Year	Description	Interest Rate	2009	2008
2010	Secured Medium-Term Notes	6.67%-8.02%	$ 35,000	$ 35,000
2012	Secured Medium-Term Notes	7.37%	7,000	7,000
2013	First Mortgage Bonds	6.13%	45,000	45,000
2013	First Mortgage Bonds	7.25%	30,000	30,000
2018	First Mortgage Bonds	5.95%	250,000	250,000
2018	Secured Medium-Term Notes	7.39%-7.45%	22,500	22,500
2019	First Mortgage Bonds	5.45%	90,000	90,000
2022	First Mortgage Bonds (1)	5.13%	250,000	-
2023	Secured Medium-Term Notes	7.18%-7.54%	13,500	13,500
2028	Secured Medium-Term Notes	6.37%	25,000	25,000
2032	Secured Pollution Control Bonds (2)	(2)	66,700	66,700
2034	Secured Pollution Control Bonds (3)	(3)	17,000	17,000
2035	First Mortgage Bonds	6.25%	150,000	150,000
2037	First Mortgage Bonds	5.70%	150,000	150,000
	Total secured bonds		1,151,700	901,700
2023	Unsecured Pollution Control Bonds	6.00%	4,100	4,100
	Interest rate swaps		(1,844)	(14,129)
	Total		1,153,956	891,671
	Secured Pollution Control Bonds held by Avista Corporation (2) (3)		(83,700)	(66,700)
	Total bonds		$1,070,256	$824,971

(1) In September 2009, the Company issued $250.0 million of 5.125 percent First Mortgage Bonds due in 2022.

(2) On December 31, 2008, $66.7 million of the City of Forsyth, Montana Pollution Control Revenue Refunding Bonds, Series 1999A (Avista Corporation Colstrip Project) due 2032 were remarketed. Avista Corp. purchased these Pollution Control Bonds and expects that at a later date, subject to market conditions, these bonds will be remarketed to unaffiliated investors or refunded by a new issue. Although Avista Corp. is now the holder of these Pollution Control Bonds, the bonds will not be cancelled but will remain outstanding under the City of Forsyth's indenture. However, so long as Avista Corp. is the holder, the bonds will not be reflected as an asset or a liability on Avista Corp.'s Balance Sheet.

(3) In December 2008, the City of Forsyth, Montana issued $17.0 million of its Pollution Control Revenue Refunding Bonds, Series 2008 (Avista Corp. Colstrip Project) due 2034 on behalf of Avista Corp. The proceeds of the Bonds were used to refund $17.0 million of Pollution Control Revenue Refunding Bonds,

Series 1999B (Avista Corp. Colstrip Project) issued by the City of Forsyth, Montana on behalf of Avista Corp., which were subject to remarketing or refunding on December 31, 2008. In December 2009, Avista Corp. purchased the Bonds and expects that at a later date, subject to market conditions, the bonds will be refunded or remarketed to unaffiliated investors. Although Avista Corp. is now the holder of these Pollution Control Bonds, the bonds will not be cancelled but will remain outstanding under the City of Forsyth's indenture. However, so long as Avista Corp. is the holder, the bonds will not be reflected as an asset or a liability on Avista Corp.'s Balance Sheet.

The following table details future long-term debt maturities including advances from associated companies (see Note 14) (dollars in thousands):

	2010	2011	2012	2013	2014	Thereafter	Total
Debt maturities	$35,000	$ -	$7,000	$75,000	$ -	$1,006,647	$1,123,647

Substantially all utility properties owned by the Company are subject to the lien of the Company's mortgage indenture. Under the Mortgage and Deed of Trust securing the Company's First Mortgage Bonds (including Secured Medium-Term Notes), the Company may issue additional First Mortgage Bonds in an aggregate principal amount equal to the sum of: 1) 70 percent of the cost or fair value (whichever is lower) of property additions which have not previously been made the basis of any application under the Mortgage, or 2) an equal principal amount of retired First Mortgage Bonds which have not previously been made the basis of any application under the Mortgage, or 3) deposit of cash; provided, however, that the Company may not issue any additional First Mortgage Bonds (with certain exceptions in the case of bonds issued on the basis of retired bonds) unless the Company's "net earnings" (as defined in the Mortgage) for any period of 12 consecutive calendar months out of the preceding 18 calendar months were at least twice the annual interest requirements on all mortgage securities at the time outstanding, including the First Mortgage Bonds to be issued, and on all indebtedness of prior rank. As of December 31, 2009, property additions and retired bonds would have entitled the Company to issue $668.5 million in aggregate principal amount of additional First Mortgage Bonds. However, using an interest rate of 8 percent on additional First Mortgage Bonds, and based on net earnings for the 12 months ended December 31, 2009, the net earnings test would limit the principal amount of additional bonds the Company could issue to $607.5 million.

See Note 12 for information regarding First Mortgage Bonds issued to secure the Company's obligations under its $320.0 million and $75.0 million committed line of credit agreements.

NOTE 14. ADVANCES FROM ASSOCIATED COMPANIES

In 2004, the Company issued Junior Subordinated Debt Securities, with a principal amount of $61.9 million to AVA Capital Trust III, an affiliated business trust formed by the Company. Concurrently, AVA Capital Trust III issued $60.0 million of Preferred Trust Securities to third parties and $1.9 million of Common Trust Securities to the Company. On April 1, 2009, AVA Capital Trust III redeemed all of the Preferred Trust Securities issued to third parties with a principal balance of $60.0 million and all of the Common Trust Securities issued to the Company with a principal balance of $1.9 million. Concurrently, the Company redeemed the total amount outstanding of its Junior Subordinated Debt Securities, at 100 percent of the principal amount ($61.9 million) plus accrued interest held by AVA Capital Trust III. The Company's net redemption of $60.0 million was funded by borrowings under its $320.0 million committed line of credit agreement.

In 1997, the Company issued Floating Rate Junior Subordinated Deferrable Interest Debentures, Series B, with a principal amount of $51.5 million to Avista Capital II, an affiliated business trust formed by the Company. Avista Capital II issued $50.0 million of Preferred Trust Securities with a floating distribution rate of LIBOR plus 0.875 percent, calculated and reset quarterly. The annual distribution rate paid during 2009 ranged from 1.22 percent to 3.06 percent. As of December 31, 2009, the annual distribution rate was 1.22 percent. Concurrent with the issuance of the Preferred Trust Securities, Avista Capital II issued $1.5 million of Common Trust Securities to the Company. These debt securities may be redeemed at the option of Avista Capital II on or after June 1, 2007 and mature on June 1, 2037. In December 2000, the Company purchased $10.0 million of these Preferred Trust Securities.

The Company has guaranteed the payment of distributions on, and redemption price and liquidation amount for, the Preferred Trust Securities to the extent that Avista Capital II has funds available for such payments from the respective debt securities. Upon maturity or prior redemption of such debt securities, the Preferred Trust Securities will be mandatorily redeemed.

NOTE 15. LEASES

The Company has multiple lease arrangements involving various assets, with minimum terms ranging from one to forty-five years. Rental expense under operating leases was $3.2 million in 2009 and $2.0 million in 2008. Future minimum lease payments required under operating leases having initial or remaining noncancelable lease terms in excess of one year as of December 31, 2009 were as follows (dollars in thousands):

	2010	2011	2012	2013	2014	Thereafter	Total
Minimum payments required.......	$1,275	$1,198	$1,093	$1,079	$1,077	$2,630	$8,351

NOTE 16. GUARANTEES

The Company has guaranteed the payment of distributions on, and redemption price and liquidation amount for, the Preferred Trust Securities issued by its affiliate, Avista Capital II, to the extent that this entity has funds available for such payments from its debt securities.

The output from the Lancaster Plant is contracted to Avista Turbine Power, Inc. (ATP), an affiliate of Avista Energy, through 2026 under a power purchase agreement. Avista Corp. has provided Rathdrum Power LLC, the owner of the Lancaster Plant, a guarantee under which Avista Corp. has guaranteed ATP's performance under the power purchase agreement. The majority of the rights and obligations of this agreement were conveyed to Shell Energy through the end of 2009. Beginning in January 2010, the rights and obligations under the power purchase agreement were conveyed to Avista Corp.

In connection with the transaction, on June 30, 2007, Avista Energy and its affiliates entered into an Indemnification Agreement with Shell Energy and its affiliates. Under the Indemnification Agreement, Avista Energy and Shell Energy each agree to provide indemnification of the other and the other's affiliates for certain events and matters described in the purchase and sale agreement entered into on April 16, 2007 and certain other transaction agreements. Such events and matters include, but are not limited to, the refund proceedings arising out of the western energy markets in 2000 and 2001 (see Note 22), existing litigation, tax liabilities, and matters related to storage rights at Jackson Prairie. In general, such indemnification is not required unless and until a party's claims exceed $150,000 and is limited to an aggregate amount of $30 million and a term of three years (except for agreements or transactions with terms longer than three years). These limitations do not apply to certain third party claims.

Avista Energy's obligations under the Indemnification Agreement are guaranteed by Avista Capital pursuant to a Guaranty dated June 30, 2007. This Guaranty is limited to an aggregate amount of $30 million plus certain fees and expenses. The Guaranty will terminate April 30, 2011 except for claims made prior to termination. The Company has not recorded any liability related to this guaranty.

NOTE 17. PREFERRED STOCK-CUMULATIVE (SUBJECT TO MANDATORY REDEMPTION)

The Company has 10 million authorized shares of preferred stock. The Company did not have any preferred stock outstanding as of December 31, 2009 and 2008.

NOTE 18. FAIR VALUE

Fair value represents the price that would be received to sell an asset or paid to transfer a liability (an exit price) in an orderly transaction between market participants at the measurement date. The carrying values of cash and cash equivalents, special deposits, accounts and notes receivable, accounts payable and notes payable are reasonable estimates of their fair values. Bonds and advances from associated companies are reported at carrying value on the Balance Sheets.

The following table sets forth the carrying value and estimated fair value of the Company's financial instruments not reported at estimated fair value on the Balance Sheets as of December 31, 2009 and 2008 (dollars in thousands):

	2009		2008	
	Carrying Value	Estimated Fair Value	Carrying Value	Estimated Fair Value
Bonds..	$1,072,100	$1,079,857	$839,100	$875,451
Advances from associated companies	51,547	43,534	113,403	102,027

These estimates of fair value were primarily based on available market information.

Energy commodity derivative assets and liabilities, deferred compensation assets, as well as derivatives related to interest rate swap agreements and foreign currency exchange contracts, are reported at estimated fair value on the Balance Sheets. U.S. GAAP defines a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities

(Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement).

The three levels of the fair value hierarchy are defined as follows:

Level 1 – Quoted prices are available in active markets for identical assets or liabilities. Active markets are those in which transactions for the asset or liability occur with sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 – Pricing inputs are other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reporting date. Level 2 includes those financial instruments that are valued using models or other valuation methodologies. These models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace.

Level 3 – Pricing inputs include significant inputs that are generally unobservable from objective sources. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value. Level 3 instruments include those that may be more structured or otherwise tailored to the Company's needs.

Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. The determination of the fair values incorporates various factors that not only include the credit standing of the counterparties involved and the impact of credit enhancements (such as cash deposits and letters of credit), but also the impact of Avista Corp.'s nonperformance risk on its liabilities.

The following table discloses by level within the fair value hierarchy the Company's assets and liabilities measured and reported on the Balance Sheets as of December 31, 2009 and 2008 at fair value on a recurring basis (dollars in thousands):

	Level 1	Level 2	Level 3	Counterparty Netting (1)	Total
December 31, 2009					
Assets:					
Energy commodity derivatives	$ -	$11,898	$57,276	$(15,934)	$53,240
Deferred compensation assets:					
Fixed income securities (2)	2,011	-	-	-	2,011
Equity securities (2)	5,863	-	-	-	5,863
Total	$7,874	$11,898	$57,276	$(15,934)	$61,114
Liabilities:					
Energy commodity derivatives	$ -	$27,086	$7,806	$(15,934)	$18,958
Foreign currency derivatives	-	50	-	-	50
Total	$ -	$27,136	$7,806	$(15,934)	$19,008
December 31, 2008					
Assets:					
Energy commodity derivatives	$ -	$40,104	$68,047	$(47,604)	$60,547
Deferred compensation assets:					
Fixed income securities (2)	1,889	-	-	-	1,889
Equity securities (2)	5,101	-	-	-	5,101
Interest rate swaps	-	875	-	-	875
Total	$6,990	$40,979	$68,047	$(47,604)	$68,412
Liabilities:					
Energy commodity derivatives	$ -	$110,123	$16,085	$(47,604)	$78,604

(1) The Company is permitted to net derivative assets and derivative liabilities when a legally enforceable master netting agreement exists.
(2) These assets are trading securities.

Avista Corp. enters into forward contracts to purchase or sell a specified amount of energy at a specified time, or during a specified period, in the future. These contracts are entered into as part of Avista Corp.'s management of loads and resources and certain contracts are considered derivative instruments. The difference between the amount of derivative assets and liabilities disclosed in respective levels and the amount of derivative assets and liabilities disclosed on the Balance Sheets is due to netting arrangements with certain counterparties. The Company uses quoted market prices and forward price curves to estimate the fair value of utility derivative commodity instruments included in Level 2. In particular, electric derivative valuations are performed using broker quotes, adjusted for periods in between quotable periods. Natural gas derivative valuations are estimated using New York Mercantile Exchange (NYMEX) pricing for similar instruments, adjusted for basin differences, using broker quotes. Where observable inputs are available for substantially the full term of the contract, the derivative asset or liability is included in Level 2. The Company also has certain contracts that, primarily due to the length of the respective contract, require the use of internally developed forward price estimates, which include significant inputs that may not be observable or corroborated in the market. These derivative contracts are included in Level 3. Refer to Note 6 for further discussion of the Company's energy commodity derivative assets and liabilities.

Deferred compensation assets and liabilities represent funds held by the Company in a Rabbi Trust for an Executive Deferral Plan. These funds consist of actively traded equity and bond funds with quoted prices in active markets. The balance disclosed in the table above excludes cash and cash equivalents of $1.6 million as of December 31, 2009 and $1.8 million as of December 31, 2008.

The following table presents activity for energy commodity derivative assets and (liabilities) measured at fair value using significant unobservable inputs (Level 3) for the years ended December 31 (dollars in thousands):

	Assets		Liabilities	
	2009	2008	2009	2008
Balance as of January 1	$68,047	$98,943	$(16,085)	$(36,506)
Total gains or losses (realized/unrealized):				
Included in net income	-	-	-	-
Included in other comprehensive income	-	-	-	-
Included in regulatory assets/liabilities (1)	(7,202)	(22,586)	7,747	18,715
Purchases, issuances, and settlements, net	(3,569)	(8,310)	532	1,706
Transfers to other categories	-	-	-	-
Ending balance as of December 31	$57,276	$68,047	$(7,806)	$(16,085)

(1) The WUTC and the IPUC issued accounting orders authorizing Avista Corp. to offset commodity derivative assets or liabilities with a regulatory asset or liability. This accounting treatment is intended to defer the recognition of mark-to-market gains and losses on energy commodity transactions until the period of settlement. The orders provide for Avista Corp. to not recognize the unrealized gain or loss on utility derivative commodity instruments in the Statements of Income. Realized gains or losses are recognized in the period of settlement, subject to approval for recovery through retail rates. Realized gains and losses, subject to regulatory approval, result in adjustments to retail rates through purchased gas cost adjustments, the ERM in Washington, the PCA mechanism in Idaho, and periodic general rates cases.

NOTE 19. COMMON STOCK

The Company has a Direct Stock Purchase and Dividend Reinvestment Plan under which the Company's shareholders may automatically reinvest their dividends and make optional cash payments for the purchase of the Company's common stock at current market value.

The payment of dividends on common stock is restricted by provisions of certain covenants applicable to preferred stock contained in the Company's Articles of Incorporation, as amended.

In December 2009, the Company entered into an amended and restated sales agency agreement with a sales agent to issue up to 1.25 million shares of its common stock from time to time. The Company originally entered into a sales agency agreement to issue up to 2 million shares of its common stock in December 2006. In 2008, the Company issued 750,000 shares of its common stock under this sales agency agreement. The Company did not issue any shares under this sales agency agreement in 2009.

NOTE 20. EARNINGS PER COMMON SHARE ATTRIBUTABLE TO AVISTA CORPORATION

The following table presents the computation of basic and diluted earnings per common share attributable to Avista Corporation for the years ended December 31 (in thousands, except per share amounts):

	2009	2008
Numerator:		
Net income attributable to Avista Corporation	$87,071	$73,620
Subsidiary earnings adjustment for dilutive securities	(114)	(249)
Adjusted net income attributable to Avista Corporation for computation of diluted earnings per common share	$86,957	$73,371
Denominiator:		
Weighted-average number of common shares outstanding-basic	54,694	53,637
Effect of dilutive securities:		
Contingent stock awards	163	213
Stock options	85	178
Weighted-average number of common shares outstanding-diluted	54,942	54,028
Earnings per common share attributable to Avista Corporation:		
Basic	$1.59	$1.37
Diluted	$1.58	$1.36

Total stock options outstanding excluded in the calculation of diluted earnings per common share attributable to Avista Corporation were 218,450 for 2009 and 250,950 for 2008. These stock options were excluded from the calculation because they were antidilutive based on the fact that the exercise price of the stock options was higher than the average market price of Avista Corp. common stock during the respective period.

NOTE 21. STOCK COMPENSATION PLANS

1998 Plan

In 1998, the Company adopted, and shareholders approved, the Long-Term Incentive Plan (1998 Plan). Under the 1998 Plan, certain key employees, officers and non-employee directors of the Company and its subsidiaries may be granted stock options, stock appreciation rights, stock awards (including restricted stock) and other stock-based awards and dividend equivalent rights. The Company has available a maximum of 3.5 million shares of its common stock for grant under the 1998 Plan. As of December 31, 2009, 0.7 million shares were remaining for grant under this plan.

2000 Plan

In 2000, the Company adopted a Non-Officer Employee Long-Term Incentive Plan (2000 Plan), which was not required to be approved by shareholders. The provisions of the 2000 Plan are essentially the same as those under the 1998 Plan, except for the exclusion of non-employee directors and executive officers of the Company. The Company has available a maximum of 2.5 million shares of its common stock for grant under the 2000 Plan. However, the Company currently does not plan to issue any further options or securities under the 2000 Plan. As of December 31, 2009, 1.7 million shares were remaining for grant under this plan.

Stock Compensation

The Company records compensation cost relating to share-based payment transactions in the financial statements based on the fair value of the equity or liability instruments issued. The Company recorded stock-based compensation expense of $2.9 million for 2009 and $3.0 million for 2008. The total income tax benefit recognized in the Statements of Income was $1.0 million for 2009 and $1.1 million for 2008.

Stock Options

The following summarizes stock options activity under the 1998 Plan and the 2000 Plan for the years ended December 31:

	2009	2008
Number of shares under stock options:		
Options outstanding at beginning of year	748,673	1,411,911
Options granted	-	-
Options exercised	(200,225)	(582,238)
Options canceled	(24,475)	(81,000)
Options outstanding and exercisable at end of year	523,973	748,673
Weighted average exercise price:		
Options exercised	$13.83	$13.91
Options canceled	$22.69	$21.70
Options outstanding and exercisable at end of year	$16.30	$15.85
Intrinsic value of options exercised (in thousands)	$1,180	$4,248
Intrinsic value of options outstanding (in thousands)	$2,774	$2,643

Information for options outstanding and exercisable as of December 31, 2009 is as follows:

Range of Exercise Prices	Number of Shares	Weighted Average Exercise Price	Weighted Average Remaining Life (in years)
$10.17-$12.41	285,323	$11.11	2.4
$15.88-$19.34	11,200	16.56	2.0
$20.11-$23.00	213,050	22.46	0.9
$26.59-$28.47	14,400	27.69	0.2
Total	523,973	$16.30	1.7

Total cash received from the exercise of stock options was $2.8 million for 2009 and $8.1 million for 2008. As of December 31, 2009 and 2008, the Company's stock options were fully vested and expensed.

Restricted Shares

Restricted shares vest in equal thirds each year over a three-year period and are payable in Avista Corp. common stock at the end of each year if the service condition is met. In addition to the service condition, the Company must meet a return on equity target in order for the CEO's restricted shares to vest. During the vesting period, employees are entitled to dividend equivalents which are paid when dividends on the Company's common stock are declared. Restricted stock is valued at the close of market of the Company's common stock on the grant date. The weighted average remaining vesting period for the Company's restricted shares outstanding as of December 31, 2009 was one year. The following table summarizes restricted stock activity for the years ended December 31:

	2009	2008
Unvested shares at beginning of year	55,939	28,137
Shares granted	44,400	43,400
Shares cancelled	(10,000)	(1,230)
Shares vested	(18,435)	(14,368)
Unvested shares at end of year	71,904	55,939
Weighted average fair value at grant date	$18.18	$20.05
Unrecognized compensation expense at end of year (in thousands)	$668	$691
Intrinsic value, unvested shares at end of year (in thousands)	$1,552	$1,084
Intrinsic value, shares vested during the year (in thousands)	$345	$293

Performance Shares

Performance share grants have vesting periods of three years. Performance awards entitle the recipients to dividend equivalent rights, are subject to forfeiture under certain circumstances, and are subject to meeting specific performance conditions. Based on the attainment of the performance condition, the amount of cash paid or common stock issued will range from 0 to 150 percent of the performance shares granted depending on the change in the value of the Company's common stock relative to an external benchmark. Dividend equivalent rights are accumulated and paid out only on shares that eventually vest.

Performance share awards entitle the grantee to shares of common stock or cash payable once the service condition is satisfied. Based on attainment of the performance condition, grantees may receive 0 to 150 percent of the original shares granted. The performance condition used is the Company's Total Shareholder Return performance over a three-year period as compared against other utilities; this is considered a market-based condition. Performance shares may be settled in common stock or cash at the discretion of the Company. Historically, the Company has settled these awards through issuance of stock and intends to continue this practice. These awards vest at the end of the three-year period. *Performance shares are equity awards with a market-based condition, which results in the* compensation cost for these awards being recognized over the requisite service period, provided that the requisite service period is rendered, regardless of when, if ever, the market condition is satisfied.

The Company measures (at the grant date) the estimated fair value of performance shares granted. The fair value of each performance share award was estimated on the date of grant using a statistical model that incorporates the probability of meeting performance targets based on historical returns relative to a peer group. Expected volatility was based on the historical volatility of Avista Corp. common stock over a three-year period. The expected term of the performance shares is three years based on the performance cycle. The risk-free interest rate was based on the U.S. Treasury yield at the time of grant. The compensation expense on these awards will only be adjusted for changes in forfeitures. The following summarizes the weighted average assumptions used to determine the fair value of performance shares and related compensation expense as well as the resulting estimated fair value of performance shares granted:

	2009	*2008*
Risk-free interest rate	1.3%	2.2%
Expected life, in years	3	3
Expected volatility	25.8%	20.2%
Dividend yield	3.6%	2.8%
Weighted average grant date fair value (per share)	$17.22	$16.96

The fair value includes both performance shares and dividend equivalent rights.

The following summarizes performance share activity:

	2009	2008
Opening balance of unvested performance shares	252,923	207,841
Performance shares granted	163,900	170,100
Performance shares canceled	(43,758)	(5,239)
Performance shares vested	(72,464)	(119,779)
Ending balance of unvested performance shares	300,601	252,923
Intrinsic value of unvested performance shares (in thousands)	$6,490	$4,902
Unrecognized compensation expense (in thousands)	$2,453	$2,227

The weighted average remaining vesting period for the Company's performance shares outstanding as of December 31, 2009 was 1.5 years. Unrecognized compensation expense as of December 31, 2009 will be recognized during 2010 and 2011. The following summarizes the impact of the market condition on the vested performance shares:

	2009	2008
Performance shares vested	72,464	119,779
Impact of market condition on shares vested	(72,464)	21,560
Shares of common stock earned	-	141,339
Intrinsic value of common stock earned (in thousands)	$ -	$2,739

In 2009 and 2008, the number of performance shares vested was adjusted by (100) percent and 18 percent based on the performance condition achieved. Shares earned under this plan are distributed to participants in the quarter following vesting.

Awards outstanding under the performance share grants include a dividend component that is paid in cash. This component of the performance share grants is accounted for as a liability award. These liability awards are revalued on a quarterly basis taking into account the number of awards outstanding, historical dividend rate, and the change in the value of the Company's common stock relative to an external benchmark. Over the life of these awards, the cumulative amount of compensation expense recognized will match the actual cash paid. As of December 31, 2009 and 2008, the Company had recognized compensation expense and a liability of $0.3 million and $0.5 million related to the dividend component of performance share grants.

NOTE 22. COMMITMENTS AND CONTINGENCIES

In the course of its business, the Company becomes involved in various claims, controversies, disputes and other contingent matters, including the items described in this Note. Some of these claims, controversies, disputes and other contingent matters involve litigation or other contested proceedings. For these proceedings, the Company intends to vigorously protect and defend its interests and pursue its rights. However, no assurance can be given as to the ultimate outcome of any particular matter because litigation and other contested proceedings are inherently subject to numerous uncertainties. For matters that affect Avista Corp.'s operations, the Company intends to seek, to the extent appropriate, recovery of incurred costs through the ratemaking process.

Federal Energy Regulatory Commission Inquiry

In April 2004, the Federal Energy Regulatory Commission (FERC) approved the contested Agreement in Resolution of Section 206 Proceeding (Agreement in Resolution) between Avista Corp., Avista Energy and the FERC's Trial Staff which stated that there was: (1) no evidence that any executives or employees of Avista Corp. or Avista Energy knowingly engaged in or facilitated any improper trading strategy during 2000 and 2001; (2) no evidence that Avista Corp. or Avista Energy engaged in any efforts to manipulate the western energy markets during 2000 and 2001; and (3) no finding that Avista Corp. or Avista Energy withheld relevant information from the FERC's inquiry into the western energy markets for 2000 and 2001 (Trading Investigation). The Attorney General of the State of California (California AG), the California Electricity Oversight Board, California Parties and the City of Tacoma, Washington challenged the FERC's decisions approving the Agreement in Resolution, which are now pending before the United States Court of Appeals for the Ninth Circuit (Ninth Circuit).

In May 2004, the FERC provided notice that Avista Energy was no longer subject to an investigation reviewing certain bids above $250 per MW in the short-term energy markets operated by the California Independent System Operator (CalISO) and the California Power Exchange (CalPX) from May 1, 2000 to October 2, 2000 (Bidding Investigation). That matter is also pending before the Ninth Circuit, after the California AG, Pacific Gas & Electric (PG&E), Southern California Edison Company (SCE) and the California Public Utilities Commission (CPUC) filed petitions for review in 2005.

Based on the FERC's order approving the Agreement in Resolution and the FERC's denial of rehearing requests, the Company does not expect that this proceeding will have any material adverse effect on its financial condition, results of operations or cash flows. Furthermore, based on information currently known to the Company regarding the Bidding Investigation and the fact that the FERC Staff did not find any evidence of manipulative behavior, the Company does not expect that this matter will have a material adverse effect on its financial condition, results of operations or cash flows. The Company has not accrued a liability related to this matter.

California Refund Proceeding

In July 2001, the FERC ordered an evidentiary hearing to determine the amount of refunds due to California energy buyers for purchases made in the spot markets operated by the CalISO and the CalPX during the period from October 2, 2000 to June 20, 2001 (Refund Period). Proposed refunds are based on the calculation of mitigated market clearing prices for each hour. The FERC ruled that if the refunds required by the formula would cause a seller to recover less than its actual costs for the Refund Period, sellers may document these costs and limit their refund liability commensurately. In September 2005, Avista Energy submitted its cost filing claim pursuant to the FERC's August 2005 order. That filing was accepted in orders issued by the FERC in January 2006 and November 2006. In June 2009, the FERC reversed, in part, its previous decision and ordered a compliance filing requiring an adjustment to the return on investment component of Avista Energy's cost filing. That compliance filing was made in July 2009.

The CalISO continues to work on its compliance filing for the Refund Period, which will show "who owes what to whom." In May 2009, the CalISO filed its 43rd status report on the California recalculation process confirming that the preparatory and the FERC refund recalculations are complete (as are calculations related to fuel cost allowance offsets, emission offsets, cost-recovery offsets, and the majority of the interest calculations). Once the FERC rules on several open issues, the CalISO states that it intends to: (1) perform the necessary adjustment to remove refunds associated with non-jurisdictional entities and allocate that shortfall to net refund recipients; and (2) work with the parties to the various global settlements to make appropriate adjustments to the CalISO's data in order to properly reflect those adjustments. After completing these calculations, the CalISO states that it intends to make a compliance filing with the FERC that presents the final financial position of each party that participated in its markets during the Refund Period.

The 2001 bankruptcy of PG&E resulted in a default on its payment obligations to the CalPX. As a result, Avista

Energy has not been paid for all of its energy sales during the Refund Period. Those funds are now in escrow accounts and will not be released until the FERC issues an order directing such release in the California refund proceeding. As of December 31, 2009, Avista Energy's accounts receivable outstanding related to defaulting parties in California were fully offset by reserves for uncollected amounts and funds collected from defaulting parties.

Many of the orders that the FERC has issued in the California refund proceedings were appealed to the Ninth Circuit. In October 2004, the Ninth Circuit ordered that briefing proceed in two rounds. The first round was limited to three issues: (1) which parties are subject to the FERC's refund jurisdiction in light of the exemption for government-owned utilities in section 201(f) of the Federal Power Act (FPA); (2) the temporal scope of refunds under section 206 of the FPA; and (3) which categories of transactions are subject to refunds. The second round of issues and their corresponding briefing schedules have not yet been set by the Ninth Circuit.

In September 2005, the Ninth Circuit held that the FERC did not have the authority to order refunds for sales made by municipal utilities in the California refund proceeding. In August 2006, the Ninth Circuit upheld October 2, 2000 as the refund effective date for the FPA section 206 refund proceeding, but remanded to the FERC its decision not to consider an FPA section 309 remedy for tariff violations prior to that date. Petitions for rehearing were denied in April 2009. In July 2009, Avista Energy and Avista Corp. filed a motion at the FERC, asking that the companies be dismissed from any further proceedings arising under section 309 pursuant to the remand. The filing pointed out that section 309 relief is based on tariff violations of the seller, and as to Avista Energy and Avista Corp., these allegations had already been fully adjudicated in the proceeding that gave rise to the Agreement in Resolution, discussed above. There, the FERC absolved both companies of all allegations of market manipulation or wrongdoing that would justify or permit FPA sections 206 or 309 remedies during 2000 and 2001. In November 2009, the FERC issued an order establishing an evidentiary hearing before an administrative law judge to address the issues remanded by the Ninth Circuit without addressing the Company's pending motion. In December 2009, the Company again brought the issue to the FERC's attention but its motion remains pending.

Because the resolution of the California refund proceeding remains uncertain, legal counsel cannot express an opinion on the extent of the Company's liability, if any. However, based on information currently known, the Company does not expect that the refunds ultimately ordered for the Refund Period will have a material adverse effect on its financial condition, results of operations or cash flows. This is primarily due to the fact that the FERC orders have stated that any refunds will be netted against unpaid amounts owed to the respective parties and the Company does not believe that refunds would exceed unpaid amounts owed to the Company. As such, the Company has not accrued a liability related to this matter.

Pacific Northwest Refund Proceeding

In July 2001, the FERC initiated a preliminary evidentiary hearing to develop a factual record as to whether prices for spot market sales of wholesale energy in the Pacific Northwest between December 25, 2000 and June 20, 2001 were just and reasonable. In June 2003, the FERC terminated the Pacific Northwest refund proceedings, after finding that the equities do not justify the imposition of refunds. In August 2007, the Ninth Circuit found that the FERC, in denying the request for refunds, had failed to take into account new evidence of market manipulation in the California energy market and its potential ties to the Pacific Northwest energy market and that such failure was arbitrary and capricious and, accordingly, remanded the case to the FERC, stating that the FERC's findings must be reevaluated in light of the evidence. In addition, the Ninth Circuit concluded that the FERC abused its discretion in denying potential relief for transactions involving energy that was purchased by the California Department of Water Resources (CERS) in the Pacific Northwest and ultimately consumed in California. The Ninth Circuit expressly declined to direct the FERC to grant refunds. Requests for rehearing were denied in April 2009.

In May 2009, the California AG filed a complaint against both Avista Energy and Avista Corp. seeking refunds on sales made to CERS during the period January 18, 2001 to June 20, 2001 under section 309 of the FPA (the Brown Complaint). The sales at issue are limited in scope and are duplicative of claims already at issue in the Pacific Northwest proceeding, discussed above. In August 2009, the City of Tacoma and the Port of Seattle filed a motion asking the FERC to summarily re-price sales of energy in the Pacific Northwest during 2000 and 2001. In October 2009, Avista Corp. filed, as part of the Transaction Finality Group, an answer to that motion and in addition, made its own recommendations for further proceedings in this docket. Those pleadings are pending before the FERC.

Both Avista Corp. and Avista Energy were buyers and sellers of energy in the Pacific Northwest energy market during the period between December 25, 2000 and June 20, 2001 and, if refunds were ordered by the FERC, could be liable to make payments, but also could be entitled to receive refunds from other FERC-jurisdictional entities. The opportunity to make claims against non-jurisdictional entities may be limited based on existing law. The Company cannot predict the outcome of this proceeding or the amount of any refunds that Avista Corp. or Avista

Energy could be ordered to make or could be entitled to receive. Therefore, the Company cannot predict the potential impact the outcome of this matter could ultimately have on the Company's results of operations, financial condition or cash flows. The Company has not accrued a liability related to this matter.

California Attorney General Complaint (the "Lockyer Complaint")
In May 2002, the FERC conditionally dismissed a complaint filed in March 2002 by the California AG that alleged violations of the FPA by the FERC and all sellers (including Avista Corp. and its subsidiaries) of electric power and energy into California. The complaint alleged that the FERC's adoption and implementation of market-based rate authority was flawed and, as a result, individual sellers should refund the difference between the rate charged and a just and reasonable rate. In May 2002, the FERC issued an order dismissing the complaint but directing sellers to re-file certain transaction summaries. It was not clear that Avista Corp. and its subsidiaries were subject to this directive but the Company took the conservative approach and re-filed certain transaction summaries in June and July of 2002. In September 2004, the Ninth Circuit upheld the FERC's market-based rate authority, but held that the FERC erred in ruling that it lacked authority to order refunds for violations of its reporting requirement. The Court remanded the case for further proceedings, but did not order any refunds, leaving it to the FERC to consider appropriate remedial options.

In March 2008, the FERC issued an order establishing a trial-type hearing to address "whether any individual public utility seller's violation of the FERC's market-based rate quarterly reporting requirement led to an unjust and unreasonable rate for that particular seller in California during the 2000-2001 period." Purchasers in the California markets will be allowed to present evidence that "any seller that violated the quarterly reporting requirement failed to disclose an increased market share sufficient to give it the ability to exercise market power and thus cause its market-based rates to be unjust and unreasonable." In particular, the parties are directed to address whether the seller at any point reached a 20 percent generation market share threshold, and if the seller did reach a 20 percent market share, whether other factors were present to indicate that the seller did not have the ability to exercise market power. The California AG, CPUC, PG&E, and SCE filed their testimony in July 2009. Avista Energy's answering testimony was filed in September 2009. On the same day, the FERC staff filed its answering testimony taking the position that, using the test the FERC directed to be applied in this proceeding, Avista Energy does not have market power. Cross answering testimony and rebuttal testimony were filed in November 2009. A hearing is expected to commence in April 2010.

Based on information currently known to the Company's management and the fact that neither Avista Corp. nor Avista Energy ever reached a 20 percent generation market share during 2000 or 2001, the Company does not expect that this matter will have a material adverse effect on its financial condition, results of operations or cash flows. The Company has not accrued any liability related to this matter.

Colstrip Generating Project Complaints
In March 2007, two families that own property near the holding ponds from Units 3 & 4 of the Colstrip Generating Project (Colstrip) filed a complaint against the owners of Colstrip and Hydrometrics, Inc. in Montana District Court. Avista Corp. owns a 15 percent interest in Units 3 & 4 of Colstrip. The plaintiffs allege that the holding ponds and remediation activities have adversely impacted their property. They allege contamination, decrease in water tables, reduced flow of streams on their property and other similar impacts to their property. They also seek punitive damages, attorney's fees, an order by the court to remove certain ponds, and the forfeiture of profits earned from the generation of Colstrip. The trial is set to begin in May 2011. Because the resolution of this complaint remains uncertain, legal counsel cannot express an opinion on the extent, if any, of the Company's liability. However, based on information currently known to the Company's management, the Company does not expect this complaint will have a material adverse effect on its financial condition, results of operations or cash flows. The Company has not accrued a liability related to this matter.

Harbor Oil Inc. Site
Avista Corp. used Harbor Oil Inc. (Harbor Oil) for the recycling of waste oil and non-PCB transformer oil in the late 1980s and early 1990s. In June 2005, the Environmental Protection Agency (EPA) Region 10 provided notification to Avista Corp. and several other parties, as customers of Harbor Oil, that the EPA had determined that hazardous substances were released at the Harbor Oil site in Portland, Oregon and that Avista Corp. and several other parties may be liable for investigation and cleanup of the site under the Comprehensive Environmental Response, Compensation, and Liability Act, commonly referred to as the federal "Superfund" law, which provides for joint and several liability. The initial indication from the EPA is that the site may be contaminated with PCBs, petroleum hydrocarbons, chlorinated solvents and heavy metals. Six potentially responsible parties, including Avista Corp., signed an Administrative Order on Consent with the EPA on May 31, 2007 to conduct a remedial investigation and feasibility study (RI/FS). The total cost of the RI/FS is estimated to be $1.5 million and it is expected that it will be

completed by early 2011. The actual cleanup, if any, will not occur until the RI/FS is complete. Based on the review of its records related to Harbor Oil, the Company does not believe it is a major contributor to this potential environmental contamination based on the small volume of waste oil it delivered to the Harbor Oil site. However, there is currently not enough information to allow the Company to assess the probability or amount of a liability, if any, being incurred. Other than its share of the RI/FS, the Company has not accrued a liability related to this matter.

Lake Coeur d'Alene

In July 1998, the United States District Court for the District of Idaho issued its finding that the Coeur d'Alene Tribe (the Tribe) owns, among other things, portions of the bed and banks of Lake Coeur d'Alene (Lake) lying within the current boundaries of the Tribe's reservation lands. The United States District Court decision was affirmed by the United States Court of Appeals for the Ninth Circuit and the United States Supreme Court in June 2001. This ownership decision resulted in, among other things, Avista Corp. being liable to the Tribe for water storage on the Tribe's land and for the use of the Tribe's reservation lands under Section 10(e) of the Federal Power Act (Section 10(e) payments). The Company's Post Falls Hydroelectric Generating Station (Post Falls) controls the water level in the Lake for portions of the year (including portions of the lakebed owned by the Tribe).

In December 2008, Avista Corp., the Tribe and the United States Department of Interior (DOI) finalized an agreement regarding a range of issues related to Post Falls and the Lake. The agreement establishes the amount of past and future compensation Avista Corp. will pay for Section 10(e) payments and issues related to licensing of the Company's hydroelectric generating facilities located on the Spokane River (see Spokane River Licensing below).

Avista Corp. agreed to compensate the Tribe a total of $39 million ($25 million paid in 2008, $10 million paid in 2009 and $4 million to be paid in 2010) for trespass and Section 10(e) payments for past storage of water for the period from 1907 through 2007. Avista Corp. agreed to compensate the Tribe for future storage of water through Section 10(e) payments of $0.4 million per year beginning in 2008 and continuing through the first 20 years of the new license and $0.7 million per year through the remaining term of the license.

In addition to Section 10(e) payments, Avista Corp. agreed to make annual payments over the life of the new FERC license to fund a variety of protection, mitigation and enhancement measures on the Coeur d'Alene Reservation required under Section 4(e) of the Federal Power Act. These payments involve creation of a Coeur d'Alene Reservation Trust Restoration Fund (the Trust Fund). Annual payments from the Company to the Trust Fund for protection, mitigation and enhancement measurements commenced with the issuance of the new FERC license in June 2009 and total $100 million over the 50-year license term.

The WUTC and IPUC approved deferral and future recovery of amounts paid to the Tribe and the Trust Fund through general rate cases in 2009.

On January 27, 2009, the Public Counsel Section of the Washington Attorney General's Office (Public Counsel) filed a Petition for Judicial Review (in Thurston County Superior Court) of the WUTC's December 2008 order approving the Company's general rate case settlement. Public Counsel raised a number of issues that were previously argued before the WUTC. These include whether the recovery of settlement costs associated with resolving the dispute with the Tribe would constitute illegal "retroactive ratemaking" (the Washington portion of these costs was $25.2 million). Public Counsel also questioned whether the WUTC's decision to entertain supplemental testimony to update the Company's filing for power supply costs during the course of the proceedings was appropriate. Finally, Public Counsel argued that the settlement improperly included advertising costs, dues and donations, and certain other expenses. The appeal itself did not prevent the new rates from going into effect.

On December 18, 2009, the Thurston County Superior Court affirmed the decision of the WUTC and rejected the arguments of Public Counsel, with the exception of disallowing $0.1 million of miscellaneous expenses, including charitable donations. Public Counsel has until March 4, 2010 to further appeal the WUTC's decision.

Spokane River Licensing

The Company owns and operates six hydroelectric plants on the Spokane River. Five of these (Long Lake, Nine Mile, Upper Falls, Monroe Street, and Post Falls, which have a total present capability of 144.1 MW) are under one FERC license and are referred to as the Spokane River Project. The sixth, Little Falls, is operated under separate Congressional authority and is not licensed by the FERC. The FERC issued a new single 50-year license for the Spokane River Project on June 18, 2009.

The license incorporated the 4(e) conditions that were included in the December 2008 Settlement Agreement with the DOI and the Tribe, as well as the mandatory conditions that were agreed to in the Idaho 401 Water Quality

Certifications and in the amended Washington 401 Water Quality Certification. Various issues that were appealed under the Washington 401 Water Quality Certification were subsequently resolved through settlement.

As part of the Settlement Agreement with the Washington Department of Ecology (DOE), the Company is currently engaged with the DOE and the EPA Total Maximum Daily Load (TMDL) process for the Spokane River and Lake Spokane, the reservoir created by Long Lake Dam. On February 12, 2010, the DOE submitted the TMDL for the EPA's review and approval. Once the TMDL process is completed, and the Company's level of responsibility related to low dissolved oxygen in Lake Spokane is established, the Company will identify potential mitigation measures. It is not possible to provide cost estimates at this time because the mitigation measures have not been fully indentified or approved by the DOE. It is also possible the TMDL will be appealed by one or more parties if it is approved by the EPA.

The Company has begun implementing the environmental and operational conditions required in the license for the Spokane River Project. The estimated cost to implement the license conditions for the five hydroelectric plants is $334 million over the 50 year license term. This will increase the Spokane River Project's cost of power by about 40 percent, while decreasing annual generation by approximately one-half of one percent. Costs to implement mitigation measures related to the TMDL are not included in these cost estimates.

The IPUC and the WUTC approved the recovery of licensing costs through the general rate case settlements in 2009. The Company will continue to seek recovery, through the ratemaking process, of all operating and capitalized costs related to the licensing of the Spokane River Project.

Clark Fork Settlement Agreement

Dissolved atmospheric gas levels in the Clark Fork River exceed state of Idaho and federal water quality standards downstream of the Cabinet Gorge Hydroelectric Generating Project (Cabinet Gorge) during periods when excess river flows must be diverted over the spillway. In 2002, the Company submitted a Gas Supersaturation Control Program ("GSCP") with the Idaho Department of Environmental Quality (Idaho DEQ) and U.S. Fish and Wildlife Service (USFWS). This submission was part of the Clark Fork Settlement Agreement for licensing the use of Cabinet Gorge. The GSCP provides for the opening and modification of possibly two diversion tunnels around Cabinet Gorge to allow streamflow to be diverted when flows are in excess of powerhouse capacity. In 2007, engineering studies determined that the tunnels would not sufficiently reduce Total Dissolved Gas (TDG). In consultation with the Idaho DEQ and the USFWS, the Company developed addendum to the GSCP. The GSCP addendum abandons the existing concept to reopen the two diversion tunnels and requires the Company to evaluate a variety of smaller capacity options to abate TDG over the next several years. The addendum was filed with the FERC in October 2009 and is pending approval.

In 1999, the USFWS listed bull trout as threatened under the Endangered Species Act. The Clark Fork Settlement Agreement describes programs intended to restore bull trout populations in the project area. Using the concept of adaptive management and working closely with the USFWS, the Company is evaluating the feasibility of fish passage at Cabinet Gorge and Noxon Rapids. The results of these studies will help the Company and other parties determine the best use of funds toward continuing fish passage efforts or other bull trout population enhancement measures. In the fall of 2009 the Company initiated a contractor selection process for the design of a permanent upstream passage facility at Cabinet Gorge. On January 13, 2010, the USFWS proposed to revise its 2005 designation of critical habitat for the bull trout. The proposed revisions include the lower Clark Fork River as critical habitat. The USFWS is accepting public comment on the proposed revisions until March 15, 2010. The Company is reviewing the proposed revisions.

Air Quality

The Company must be in compliance with requirements under the Clean Air Act and Clean Air Act Amendments for its thermal generating plants. The Company continues to monitor legislative developments at both the state and national level for the potential of further restrictions on sulfur dioxide, nitrogen oxide and carbon dioxide, as well as other greenhouse gas and mercury emissions.

In 2006, the Montana Department of Environmental Quality (Montana DEQ) adopted final rules for the control of mercury emissions from coal-fired plants. The new rules set strict mercury emission limits by 2010, and put in place a recurring ten-year review process to ensure facilities are keeping pace with advancing technology in mercury emission control. The rules also provide for temporary alternate emission limits provided certain provisions are met, and they allocate mercury emission credits in a manner that rewards the cleanest facilities.

Compliance with new and proposed requirements and possible additional legislation or regulations results in increases to capital expenditures and operating expenses for expanded emission controls at the Company's thermal generating facilities. The Company, along with the other owners of Colstrip, completed the first phase of testing on two mercury control technologies. The joint owners of Colstrip believe, based upon current results, that the plant will be able to comply with the Montana law without utilizing the temporary alternate emission limit provision. Current estimates indicate that the Company's share of installation capital costs will be $1.4 million and annual operating costs will increase by $1.5 million (began in late-2009). The Company will continue to seek recovery, through the ratemaking process, of the costs to comply with various air quality requirements.

Aluminum Recycling Site

In October 2009, the Company (through its subsidiary Pentzer Corporation) received notice from the DOE proposing to find Pentzer liable for a release of hazardous substances under the Model Toxics Control Act (MTCA), under Washington state law. The subject property adjoins land owned by the Union Pacific Railroad (UPR). UPR leased their property to operators of a facility designated by DOE as "Aluminum Recycling – Trentwood." Operators of that property maintained piles of aluminum "black dross," which can be designated as a state-only dangerous waste in Washington State. Operators placed a portion of the aluminum dross pile on the site owned by Pentzer Corporation. The Company does not believe it is a contributor to any environmental contamination associated with the dross pile, and submitted a response to the DOE's proposed findings in November 2009. In December 2009, the Company received notice from the DOE that it had been designated as a potentially liable party for any hazardous substances located on this site. There is currently not enough information to allow the Company to assess the probability or amount of a liability, if any, being incurred. The Company has not accrued a liability related to this matter.

Collective Bargaining Agreements

As of December 31, 2009, the Company's collective bargaining agreement with the International Brotherhood of Electrical Workers represented approximately 45 percent of all of Avista Corp.'s employees. The agreement with the local union in Washington and Idaho representing the majority (approximately 90 percent) of the bargaining unit employees expires on March 26, 2010. Two local agreements in Oregon, which cover approximately 50 employees, expire in April 2010. Negotiations are currently ongoing for these labor agreements.

Other Contingencies

In the normal course of business, the Company has various other legal claims and contingent matters outstanding. The Company believes that any ultimate liability arising from these actions will not have a material adverse impact on its financial condition, results of operations or cash flows. It is possible that a change could occur in the Company's estimates of the probability or amount of a liability being incurred. Such a change, should it occur, could be significant.

The Company routinely assesses, based on in-depth studies, expert analyses and legal reviews, its contingencies, obligations and commitments for remediation of contaminated sites, including assessments of ranges and probabilities of recoveries from other responsible parties who have and have not agreed to a settlement and recoveries from insurance carriers. The Company's policy is to accrue and charge to current expense identified exposures related to environmental remediation sites based on estimates of investigation, cleanup and monitoring costs to be incurred.

The Company has potential liabilities under the Endangered Species Act for species of fish that have either already been added to the endangered species list, been listed as "threatened" or been petitioned for listing. Thus far, measures adopted and implemented have had minimal impact on the Company.

Under the federal licenses for its hydroelectric projects, the Company is obligated to protect its property rights, including water rights. The state of Montana is examining the status of all water right claims within state boundaries. Claims within the Clark Fork River basin could potentially adversely affect the energy production of the Company's Cabinet Gorge and Noxon Rapids hydroelectric facilities. The state of Idaho is conducting an adjudication in northern Idaho, which will ultimately include both the lower Clark Fork River, the Spokane River and the Coeur d'Alene basin. In addition, the state of Washington has indicated its intent to initiate an adjudication for the Spokane River basin in the next several years. The Company is participating in these extensive adjudication processes, which are unlikely to be concluded in the foreseeable future.

NOTE 23. INFORMATION SERVICES CONTRACTS

The Company has information services contracts that expire at various times through 2012. Total payments under these contracts were $15.5 million in 2009 and $15.4 million in 2008. The majority of the costs are included in operation expenses in the Statements of Income. Minimum contractual obligations under the Company's information services contracts are $13.2 million in 2010, $12.9 million in 2011, and $12.2 million in 2012. The largest of these contracts provides for increases due to changes in the cost of living index and further provides flexibility in the annual obligation from year-to-year subject to a three-year true-up cycle.

NOTE 24. REGULATORY MATTERS

Power Cost Deferrals and Recovery Mechanisms

Deferred power supply costs are recorded as a deferred charge on the Balance Sheets for future review and recovery through retail rates. The power supply costs deferred include certain differences between actual net power supply costs incurred by Avista Corp. and the costs included in base retail rates. This difference in net power supply costs primarily results from changes in:

- short-term wholesale market prices and sales and purchase volumes,
- the level of hydroelectric generation,
- the level of thermal generation (including changes in fuel prices), and
- retail loads.

In Washington, the ERM allows Avista Corp. to periodically increase or decrease electric rates with WUTC approval to reflect changes in power supply costs. The ERM is an accounting method used to track certain differences between actual net power supply costs and the amount included in base retail rates for Washington customers. The Company must make a filing (no sooner than January 1, 2011), to allow all interested parties the opportunity to review the ERM, and make recommendations to the WUTC related to the continuation, modification or elimination of the ERM.

The initial amount of power supply costs in excess or below the level in retail rates, which the Company either incurs the cost of, or receives the benefit from, is referred to as the deadband. The annual (calendar year) deadband amount is currently $4.0 million. The Company will incur the cost of, or receive the benefit from, 100 percent of this initial power supply cost variance. The Company shares annual power supply cost variances between $4.0 million and $10.0 million with its customers. There is a 50 percent customers/50 percent Company sharing when actual power supply expenses are higher (surcharge to customers) than the amount included in base retail rates within this band. There is a 75 percent customers/25 percent Company sharing when actual power supply expenses are lower (rebate to customers) than the amount included in base retail rates within this band. To the extent that the annual power supply cost variance from the amount included in base rates exceeds $10.0 million, 90 percent of the cost variance is deferred for future surcharge or rebate. The Company absorbs or receives the benefit in power supply costs of the remaining 10 percent of the annual variance beyond $10.0 million without affecting current or future customer rates. The following is a summary of the ERM:

Annual Power Supply Cost Variability	Deferred for Future Surcharge or Rebate to Customers	Expense or Benefit to the Company
+/- $0 - $4 million	0%	100%
+ between $4 million - $10 million	50%	50%
- between $4 million - $10 million	75%	25%
+/- excess over $10 million	90%	10%

Avista Corp. has a PCA mechanism in Idaho that allows it to modify electric rates on October 1 of each year with Idaho Public Utilities Commission (IPUC) approval. Under the PCA mechanism, Avista Corp. defers 90 percent of the difference between certain actual net power supply expenses and the amount included in base retail rates for its Idaho customers. In June 2007, the IPUC approved continuation of the PCA mechanism with an annual rate adjustment provision. These annual October 1 rate adjustments recover or rebate power costs deferred during the preceding July-June twelve-month period.

The following table shows activity in deferred power costs for Washington and Idaho during 2008 and 2009 (dollars in thousands):

	Washington	Idaho	Total
Deferred power costs as of December 31, 2007	$58,524	$21,163	$79,687
Activity from January 1 – December 31, 2008:			
Power costs deferred	7,049	10,029	17,078
Interest and other net additions	2,231	1,153	3,384
Recovery of deferred power costs through retail rates	(30,852)	(11,690)	(42,542)
Deferred power costs as of December 31, 2008	36,952	$20,655	57,607

Activity from January 1 – December 31, 2009:			
Power costs deferred	-	17,985	17,985
Interest and other net additions	879	388	1,267
Recovery of deferred power costs through retail rates	(31,567)	(17,521)	(49,088)
Deferred power costs as of December 31, 2009	$ 6,264	$21,507	$27,771

In February 2010, the WUTC approved the Company's request to eliminate the existing ERM surcharge. The surcharge was eliminated because the previous balance of deferred power costs has been substantially recovered. This will result in an overall rate reduction of 7 percent for the Company's Washington customers with no impact on income from operations or net income.

Natural Gas Cost Deferrals and Recovery Mechanisms

Avista Corp. files a purchased gas cost adjustment (PGA) in all three states it serves to adjust natural gas rates for: 1) estimated commodity and pipeline transportation costs to serve natural gas customers for the coming year, and 2) the difference between actual and estimated commodity and transportation costs for the prior year. These annual PGA filings in Washington and Idaho provide for the deferral, and recovery or refund, of 100 percent of the difference between actual and estimated commodity and pipeline transportation costs for the prior year, subject to applicable regulatory review. The annual PGA filing in Oregon provides for deferral, and recovery or refund, of 100 percent of the difference between actual and estimated pipeline transportation costs and commodity costs that are fixed through hedge transactions. Commodity costs that are not hedged for Oregon customers are subject to a sharing mechanism whereby Avista Corp. defers, and recovers or refunds, 90 percent of the difference between these actual and estimated costs. Total net deferred natural gas costs to be refunded to customers were a liability of $40.0 million as of December 31, 2009 and $18.6 million as of December 31, 2008.

General Rate Cases

The following is a summary of the Company's authorized rates of return in each jurisdiction:

Jurisdiction and service	Implementation Date	Authorized Overall Rate of Return	Authorized Return on Equity	Authorized Equity Level
Washington electric and natural gas	January 2010	8.25%	10.2%	46.5%
Idaho electric and natural gas	August 2009	8.55%	10.5%	50.0%
Oregon natural gas	November 2009	8.19%	10.1%	50.0%

Washington General Rate Cases

As approved by the WUTC, on January 1, 2008, electric rates for the Company's Washington customers increased by an average of 9.4 percent, which was designed to increase annual revenues by $30.2 million. As part of this general rate increase, the base level of power supply costs used in the ERM calculations was updated. Also, on January 1, 2008, natural gas rates increased by an average of 1.7 percent, which was designed to increase annual revenues by $3.3 million.

In September 2008, Avista Corp. entered into a settlement stipulation in its general rate case that was filed with the WUTC in March 2008. This settlement stipulation was approved by the WUTC in December 2008. The new electric and natural gas rates became effective on January 1, 2009. As agreed to in the settlement, base electric rates for the Company's Washington customers increased by an average of 9.1 percent, which was designed to increase annual revenues by $32.5 million. Base natural gas rates for the Company's Washington customers increased by an average of 2.4 percent, which was designed to increase annual revenues by $4.8 million.

On January 27, 2009, Public Counsel filed a Petition for Judicial Review (in Thurston County Superior Court) of the WUTC's December 2008 order approving Avista Corp.'s multiparty settlement. Public Counsel raised a number of issues that were previously argued before the WUTC. These included whether the recovery of settlement costs associated with resolving the dispute with the Coeur d'Alene Tribe would constitute illegal "retroactive ratemaking" (the Washington portion of these costs was $25.2 million). Public Counsel also questioned whether the WUTC's decision to entertain supplemental testimony by the Company to update its filing for power supply costs during the course of the proceedings was appropriate. Finally, Public Counsel argued that the settlement improperly included advertising costs, dues and donations, and certain other expenses. The appeal itself did not prevent the new rates from going into effect.

On December 18, 2009, the Thurston County Superior Court affirmed the decision of the WUTC and rejected the arguments of Public Counsel, with the exception of disallowing $0.1 million of miscellaneous expenses, including charitable donations. Public Counsel has until March 4, 2010 to further appeal the WUTC's decision.

On December 22, 2009, the WUTC issued an order on Avista Corp.'s electric and natural gas rate general rate cases that were filed with the WUTC in January 2009. The WUTC approved a base electric rate increase for the Company's Washington customers of 2.8 percent, which is designed to increase annual revenues by $12.1 million. Base natural gas rates for the Company's Washington customers increased by an average of 0.3 percent, which is designed to increase annual revenues by $0.6 million. The new electric and natural gas rates became effective on January 1, 2010.

Following the execution of a partial settlement stipulation in September 2009, Avista Corp. revised downward its electric rate increase request from $69.8 million to $37.5 million, primarily due to the decline in the wholesale prices of electricity and natural gas. Avista Corp. also reduced its natural gas request from $4.9 million to $2.8 million. Under the partial settlement stipulation, the Company reached agreement with the other settling parties on issues in the areas of cost of capital, power supply, rate spread and rate design, and funding under the Low-Income Ratepayer Assistance Program. The WUTC approved this partial settlement stipulation in its order on December 22, 2009.

The WUTC did not allow Avista Corp. to include the costs associated with the power purchase agreement for the Lancaster Plant in rates, indicating the Company did not demonstrate compliance with certain requirements necessary for immediate inclusion in rates. However, the WUTC directed Avista Corp. to file to defer costs associated with the Lancaster Plant, with a carrying charge, for potential recovery in a future rate proceeding if the Company demonstrates that it has satisfied these requirements. The Company's proposed deferred accounting treatment for the net costs associated with the Lancaster Plant was approved by the WUTC in February 2010. The net costs associated with the power purchase agreement for the Lancaster Plant account for approximately half of the difference between the Company's revised electric rate increase request of $37.5 million and the $12.1 million increase approved by the WUTC.

The WUTC also did not allow for certain pro forma future capital additions to rate base, as well as certain increases in labor costs, tree trimming costs and information systems costs. These costs account for the majority of the remaining difference between the Company's revised electric rate increase request and the amount approved by the WUTC.

The partial settlement stipulation (as approved by the WUTC on December 22, 2009) is based on an overall rate of return of 8.25 percent with a common equity ratio of 46.5 percent and a 10.2 percent return on equity. The Company's original request was based on a proposed overall rate of return of 8.68 percent with a common equity ratio of 47.5 percent and an 11.0 percent return on equity.

Idaho General Rate Cases

In August 2008, the Company entered into an all-party settlement stipulation in its general rate case that was filed with the IPUC in April 2008. This settlement stipulation was approved by the IPUC in September 2008. The new electric and natural gas rates became effective on October 1, 2008. As agreed to in the settlement, base electric rates for the Company's Idaho customers increased by an average of 12.0 percent, which was designed to increase annual revenues by $23.2 million. Base natural gas rates for the Company's Idaho customers increased by an average of 4.7 percent, which was designed to increase annual revenues by $3.9 million.

In June 2009, the Company entered into an all-party settlement stipulation in its electric and natural gas general rate cases that were filed with the IPUC in January 2009. This settlement stipulation was approved by the IPUC in July 2009. The new electric and natural gas rates became effective on August 1, 2009. As agreed to in the settlement, base electric rates for the Company's Idaho customers increased by an average of 5.7 percent, which was designed to increase annual revenues by $12.5 million. Offsetting the base electric rate increase was an overall 4.2 percent decrease in the PCA surcharge, which was designed to decrease annual PCA revenues by $9.3 million, resulting in a net increase in annual revenues of $3.2 million. Base natural gas rates for the Company's Idaho customers increased by an average of 2.1 percent, which was designed to increase annual revenues by $1.9 million. Offsetting the natural gas rate increase for residential customers was an equivalent PGA decrease of 2.1 percent. Large general services received a PGA decrease of 2.4 percent and interruptible services received a PGA decrease of 2.8 percent. The overall PGA decrease resulted in a $2.0 million decrease in annual PGA revenues, resulting in a net decrease in annual revenues of $0.1 million. The PGAs are designed to pass through changes in natural gas costs to customers with no change in gross margin or net income.

Oregon General Rate Cases

As approved by the OPUC in March 2008, natural gas rates for the Company's Oregon customers increased 0.4 percent effective April 1, 2008 (designed to increase annual revenues by $0.5 million) and increased an additional 1.1 percent effective November 1, 2008 (designed to increase annual revenues by an additional $1.4 million).

In September 2009, the Company entered into an all-party settlement stipulation in its general rate case that was filed with the OPUC in June 2009. This settlement stipulation was approved by the OPUC in October 2009. The new natural gas rates became effective on November 1, 2009. As agreed to in the settlement, base natural gas rates for Oregon customers increased by an average of 7.1 percent, whicb is designed to increase annual revenues by $8.8 million.

Company Name: Avista Corporation

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

Year: 2009

	Account Number & Title	Last Year	This Year	% Change
1				
2	**Intangible Plant**			
3				
4	301 Organization			
5	302 Franchises & Consents	6,222,448	6,222,448	
6	303 Miscellaneous Intangible Plant	(20,356)	136,358	-115%
7				
8	**TOTAL Intangible Plant**	6,202,092	6,358,806	-2%
9				
10	**Production Plant**			
11				
12	Steam Production			
13				
14	310 Land & Land Rights	1,290,825	1,289,446	0%
15	311 Structures & Improvements	100,045,629	100,084,999	0%
16	312 Boiler Plant Equipment	122,467,682	125,494,031	-2%
17	313 Engines & Engine Driven Generators			
18	314 Turbogenerator Units	34,405,081	34,930,852	-2%
19	315 Accessory Electric Equipment	16,066,109	16,092,422	0%
20	316 Miscellaneous Power Plant Equipment	13,011,813	13,050,436	0%
21	317 Asset Retirement Costs	134,588	134,588	
22	**TOTAL Steam Production Plant**	287,421,727	291,076,774	-1%
23				
24	Nuclear Production			
25				
26	320 Land & Land Rights			
27	321 Structures & Improvements			
28	322 Reactor Plant Equipment			
29	323 Turbogenerator Units			
30	324 Accessory Electric Equipment			
31	325 Miscellaneous Power Plant Equipment			
32				
33	**TOTAL Nuclear Production Plant**			
34				
35	Hydraulic Production			
36				
37	330 Land & Land Rights	42,868,347	42,868,347	
38	331 Structures & Improvements	13,358,295	13,681,423	-2%
39	332 Reservoirs, Dams & Waterways	33,179,949	33,294,257	0%
40	333 Water Wheels, Turbines & Generators	49,802,776	66,930,837	-26%
41	334 Accessory Electric Equipment	14,150,152	14,202,047	0%
42	335 Miscellaneous Power Plant Equipment	2,693,024	3,391,019	-21%
43	336 Roads, Railroads & Bridges	225,369	225,369	
44				
45	**TOTAL Hydraulic Production Plant**	156,277,912	174,593,299	-10%

Company Name: Avista Corporation

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

Year: 2009

	Account Number & Title	Last Year	This Year	% Change
1				
2	Production Plant (cont.)			
3				
4	Other Production			
5				
6	340 Land & Land Rights			
7	341 Structures & Improvements			
8	342 Fuel Holders, Producers & Accessories			
9	343 Prime Movers			
10	344 Generators			
11	345 Accessory Electric Equipment			
12	346 Miscellaneous Power Plant Equipment			
13				
14	**TOTAL Other Production Plant**			
15				
16	**TOTAL Production Plant**	443,699,639	465,670,073	-5%
17				
18	**Transmission Plant**			
19				
20	350 Land & Land Rights	883,384	883,384	
21	352 Structures & Improvements	477,507	477,507	
22	353 Station Equipment	16,618,729	16,854,955	-1%
23	354 Towers & Fixtures	16,042,605	16,057,320	0%
24	355 Poles & Fixtures	7,201,094	7,214,834	0%
25	356 Overhead Conductors & Devices	15,778,629	15,790,678	0%
26	357 Underground Conduit			
27	358 Underground Conductors & Devices			
28	359 Roads & Trails	367,476	367,476	
29				
30	**TOTAL Transmission Plant**	57,369,424	57,646,154	0%
31				
32	**Distribution Plant**			
33				
34	360 Land & Land Rights			
35	361 Structures & Improvements	15,881	15,881	
36	362 Station Equipment	152,268	152,268	
37	363 Storage Battery Equipment			
38	364 Poles, Towers & Fixtures	36,113	34,907	3%
39	365 Overhead Conductors & Devices	10,273	10,038	2%
40	366 Underground Conduit	46	46	
41	367 Underground Conductors & Devices	637	637	
42	368 Line Transformers	1,257	1,257	
43	369 Services	127	127	
44	370 Meters	29	29	
45	371 Installations on Customers' Premises			
46	372 Leased Property on Customers' Premises			
47	373 Street Lighting & Signal Systems			
48				
49	**TOTAL Distribution Plant**	216,631	215,190	

MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

Year: 2009

	Account Number & Title	Last Year	This Year	% Change
1				
2	**General Plant**			
3				
4	389 Land & Land Rights			
5	390 Structures & Improvements			
6	391 Office Furniture & Equipment			
7	392 Transportation Equipment	203,572	214,076	-5%
8	393 Stores Equipment			
9	394 Tools, Shop & Garage Equipment	11,972	9,486	26%
10	395 Laboratory Equipment			
11	396 Power Operated Equipment	41,044	41,064	0%
12	397 Communication Equipment	688,952	689,958	0%
13	398 Miscellaneous Equipment			
14	399 Other Tangible Property			
15				
16	**TOTAL General Plant**	945,540	954,584	
17				
18	**TOTAL Electric Plant in Service**	508,433,326	530,844,807	

MONTANA DEPRECIATION SUMMARY

Year: 2009

	Functional Plant Classification	Plant Cost	Accumulated Depreciation Last Year Bal.	This Year Bal.	Current Avg. Rate
1					
2	*Steam Production*	291,076,774	183,586,040	190,497,169	N/A
3	Nuclear Production				
4	Hydraulic Production	174,593,299	21,222,470	24,233,860	N/A
5	Other Production				
6	Transmission	57,646,154	18,896,507	19,369,427	N/A
7	Distribution	215,190	65,112	64,511	N/A
8	General		1,969,161	2,328,700	N/A
9	**TOTAL**	523,531,417	225,739,290	236,493,667	

MONTANA MATERIALS & SUPPLIES (ASSIGNED & ALLOCATED)

SCHEDULE 21

	Account	Last Year Bal.	This Year Bal.	%Change
1				
2	151 Fuel Stock	1,180,136	1,048,057	13%
3	152 Fuel Stock Expenses Undistributed			
4	153 Residuals			
5	154 Plant Materials & Operating Supplies:			
6	Assigned to Construction (Estimated)			
7	Assigned to Operations & Maintenance			
8	Production Plant (Estimated)	1,911,080	1,900,140	1%
9	*Transmission Plant (Estimated)*			
10	Distribution Plant (Estimated)			
11	Assigned to Other			
12	155 Merchandise			
13	156 Other Materials & Supplies			
14	157 Nuclear Materials Held for Sale			
15	163 Stores Expense Undistributed			
16				
17	**TOTAL Materials & Supplies**	3,091,216	2,948,197	5%

MONTANA REGULATORY CAPITAL STRUCTURE & COSTS

SCHEDULE 22

	Commission Accepted - Most Recent	% Cap. Str.	% Cost Rate	Weighted Cost
1	Docket Number			
2	Order Number			
3		**Reference is made to Schedule 27**		
4	Common Equity			
5	Preferred Stock			
6	Long Term Debt			
7	Other			
8	**TOTAL**			
9				
10	Actual at Year End			
11				
12	Common Equity			
13	Preferred Stock			
14	Long Term Debt			
15	Other			
16	**TOTAL**			

STATEMENT OF CASH FLOWS

Year: 2009

	Description	Last Year	This Year	% Change
1				
2	Increase/(decrease) in Cash & Cash Equivalents:			
3				
4	**Cash Flows from Operating Activities:**			
5	Net Income	73,619,720	87,071,250	-15%
6	Depreciation	90,390,864	96,233,438	-6%
7	Amortization	52,958,619	59,481,435	-11%
8	Deferred Income Taxes - Net	41,798,683	9,011,417	364%
9	Investment Tax Credit Adjustments - Net	(49,308)	5,258,780	-101%
10	Change in Operating Receivables - Net	(116,961,581)	18,733,830	-724%
11	Change in Materials, Supplies & Inventories - Net	(18,855,778)	16,449,128	-215%
12	Change in Operating Payables & Accrued Liabilities - Net	2,228,853	(27,996,937)	108%
13	Allowance for Funds Used During Construction (AFUDC)	(5,692,491)	(3,078,244)	-85%
14	Change in Other Assets & Liabilities - Net	(26,239,000)	(31,216,136)	16%
15	Other Operating Activities (explained on attached page)	(2,562,188)	(670,269)	-282%
16	**Net Cash Provided by/(Used in) Operating Activities**	90,636,393	229,277,692	-60%
17				
18	**Cash Inflows/Outflows From Investment Activities:**			
19	Construction/Acquisition of Property, Plant and Equipment	(219,796,264)	(206,916,479)	-6%
20	(net of AFUDC & Capital Lease Related Acquisitions)			
21	Acquisition of Other Noncurrent Assets			
22	Proceeds from Disposal of Noncurrent Assets	7,998,322	128,775	6111%
23	Investments In and Advances to Affiliates			
24	Contributions and Advances from Affiliates	1,191,118	4,689,731	-75%
25	Disposition of Investments in and Advances to Affiliates			
26	Other Investing Activities (explained on attached page)	2,012,509	(1,000,477)	301%
27	**Net Cash Provided by/(Used in) Investing Activities**	(208,594,315)	(203,098,450)	-3%
28				
29	**Cash Flows from Financing Activities:**			
30	Proceeds from Issuance of:			
31	Long-Term Debt	296,165,000	249,425,000	19%
32	Preferred Stock			
33	Common Stock	28,564,671	2,621,946	989%
34	Long-Term Debt to Affiliated Trusts			
35	Net Increase in Short-Term Debt	250,000,000		#DIV/0!
36	Other:			
37	Payment for Retirement of:			
38	Long-Term Debt	(401,855,029)	(78,931,206)	-409%
39	Preferred Stock			
40	Common Stock			
41	Long-Term Debt to Affiliated Trusts			
42	Net Decrease in Short-Term Debt		(163,000,000)	100%
43	Dividends on Preferred Stock			
44	Dividends on Common Stock	(37,070,823)	(44,360,372)	16%
45	Other Financing Activities (explained on attached page)	(21,418,987)	7,049,824	-404%
46	**Net Cash Provided by (Used in) Financing Activities**	114,384,832	(27,194,808)	521%
47				
48	**Net Increase/(Decrease) in Cash and Cash Equivalents**	(3,573,090)	(1,015,566)	-252%
49	**Cash and Cash Equivalents at Beginning of Year**	8,551,759	4,978,669	72%
50	**Cash and Cash Equivalents at End of Year**	4,978,669	3,963,103	26%

Company Name: Avista Corp. SCHEDULE 23A

STATEMENT OF CASH FLOWS

Year: 2008

	Description	Last Year	This Year	% Change
1	**Detail of Lines 15, 26 and 45**			
2	**Line 15: Other Operating Activities**			
3	Gain on disposition of property	(1,123,412)	(88,685)	
4	ESOP Dividends			
5	Change in allowance for uncollectible receivables	2,878,927	(2,133,833)	235%
6	Regulatory Gas Cost and Power Cost Adjustment	(2,735,693)	(216,487)	-1164%
7	Non-cash stock compensation	2,541,028	2,596,188	
8	Subsidiary earnings	(4,123,038)	(827,452)	-398%
9	Total Line 15	(2,562,188)	(670,269)	-282%
10				
11	**Line 26: Other Investing Activities**			
	Proceeds from sale of utility property claim			
	Changes in other property and investments	2,006,496	(1,000,477)	
12	Notes receivable	6,013	-	
13	Total Line 26	2,012,509	(1,000,477)	
10	**Line 45: Other Financing Activities**			
	Cash received (paid) in interest rate swap agreement	(16,395,000)	10,776,222	
11	Premiums paid for repurchase of debt			
12	Debt Issuance costs	(5,023,987)	(3,726,398)	
13	Total Line 45	(21,418,987)	7,049,824	

LONG TERM DEBT

Year: 2009

	Description	Issue Date Mo./Yr.	Maturity Date Mo./Yr.	Principal Amount	Net Proceeds	Outstanding Per Balance Sheet	Yield to Maturity	Annual Net Cost Inc. Prem/Disc.	Total Cost %
1									
2	Medium-Term Notes								
3	Series A	various	various	250,000,000	248,374,625	48,000,000	8.86%	4,250,689	8.86%
4	Series B	various	various	161,000,000	160,141,500	5,000,000	7.42%	371,012	7.42%
5	Series C	various	various	109,000,000	108,272,250	50,000,000	7.58%	3,790,416	7.58%
6									
7	Pollution Control Bonds								
8									
9	6% Pollution Control Bonds	7/1/93	12/1/23	4,100,000	2,838,725	4,100,000	6.52%	267,441	6.52%
10									
11									
12									
13	First Mortgage Bonds								
14	6.125% Issued September 2003	9/1/03	9/1/13	45,000,000	44,795,250	45,000,000	6.70%	3,016,248	6.70%
15	5.45% Issued November 2004	11/18/04	12/1/19	90,000,000	88,975,000	90,000,000	6.46%	5,815,418	6.46%
16	6.25% Issued Nov/Dec 2005	11/17/05	12/1/35	150,000,000	147,937,500	150,000,000	6.23%	9,342,301	6.23%
17	5.70% Issued Dec 2006	12/15/06	7/1/37	150,000,000	145,687,500	150,000,000	6.12%	9,179,740	6.12%
18	5.95% Issued April 2008	4/2/08	6/1/18	250,000,000	230,523,581	250,000,000	7.03%	17,585,352	7.03%
19	7.25% Issued Dec 2008	12/16/08	12/16/13	30,000,000	29,579,694	30,000,000	7.59%	2,277,590	7.59%
20	5.125% Issued Sept 2009	9/22/09	4/1/22	250,000,000	257,701,222	250,000,000	4.80%	11,987,116	4.79%
21									
22									
23	Junior Subordinated Debentures	6/3/97	6/1/37	51,547,000	36,828,822	51,547,000	3.96%	2,041,261	3.96%
24									
25									
26									
27									
28									
29									
30									
31									
32	**TOTAL**			1,540,647,000	1,501,655,669	1,123,647,000		69,924,584	6.22%

PREFERRED STOCK

Year: 2009

	Series	Issue Date Mo./Yr.	Shares Issued	Par Value	Call Price	Net Proceeds	Cost of Money	Principal Outstanding	Annual Cost	Embed. Cost %
1										
2										
3	N/A									
4										
5										
6										
7										
8										
9										
10										
11										
12										
13										
14										
15										
16										
17										
18										
19										
20										
21										
22										
23										
24										
25										
26										
27										
28										
29										
30										
31										
32	**TOTAL**									

Company Name: Avista Corporation **SCHEDULE 26**

COMMON STOCK

Year: 2009

Line		Avg. Number of Shares Outstanding	Book Value Per Share	Earnings Per Share	Dividends Per Share	Retention Ratio	Market Price High	Market Price Low	Price/ Earnings Ratio
1									
2									
3									
4	January								
5									
6	February								
7									
8	March	54,616,000	18.65	0.57	0.180		20.01	12.67	
9									
10	April								
11									
12	May								
13									
14	June	54,654,000	18.9	0.47	0.210		18.13	13.44	
15									
16	July								
17									
18	August								
19									
20	September	54,706,000	18.93	0.15	0.210		20.83	17.59	
21									
22	October								
23									
24	November								
25									
26	December	54,796,000	19.17	0.40	0.210		22.44	18.48	
27									
28									
29									
30									
31									
32	TOTAL Year End	54,836,781	19.17	1.59	0.81	49.06%	21.59		13.6

MONTANA EARNED RATE OF RETURN

Year: 2009

	Description	Last Year	This Year	% Change
	Rate Base			
1				
2	101 Plant in Service			
3	108 (Less) Accumulated Depreciation			
4	**NET Plant in Service**			
5				
6	Additions			
7	154, 156 Materials & Supplies			
8	165 Prepayments			
9	Other Additions			
10	**TOTAL Additions**			
11				
12	Deductions			
13	190 Accumulated Deferred Income Taxes			
14	252 Customer Advances for Construction			
15	255 Accumulated Def. Investment Tax Credits			
16	Other Deductions			
17	**TOTAL Deductions**			
18	**TOTAL Rate Base**			
19				
20	**Net Earnings**			
21				
22	**Rate of Return on Average Rate Base**			
23				
24	**Rate of Return on Average Equity**			
25				
26	Major Normalizing Adjustments & Commission			
27	Ratemaking adjustments to Utility Operations			
28				
29				
30	**Rates charged were based on the**			
31	**Company's last rate order from the Idaho**			
32	**Public Utilities Commission and accepted by**			
33	**the Montana Commission. The Company**			
34	**does not calculate separate rates of return**			
35	**for the Montana jurisdiction.**			
36				
37				
38				
39				
40				
41				
42				
43				
44				
45				
46				
47	**Adjusted Rate of Return on Average Rate Base**			
48				
49	**Adjusted Rate of Return on Average Equity**			

MONTANA COMPOSITE STATISTICS

Year: 2009

		Description	Amount
1			
2		*Plant (Intrastate Only) (000 Omitted)*	
3			
4	101	Plant in Service	530,845
5	107	Construction Work in Progress	
6	114	Plant Acquisition Adjustments	
7	105	Plant Held for Future Use	
8	154, 156	Materials & Supplies	2,948
9		(Less):	
10	108, 111	Depreciation & Amortization Reserves	(236,494)
11	252	Contributions in Aid of Construction	
12			
13		**NET BOOK COSTS**	297,299
14			
15		Revenues & Expenses (000 Omitted)	
16			
17	400	Operating Revenues	33
18			
19	403 - 407	Depreciation & Amortization Expenses	12,340
20		Federal & State Income Taxes	482
21		Other Taxes	7,167
22		Other Operating Expenses	29,459
23		TOTAL Operating Expenses	49,447
24			
25		Net Operating Income	(49,414)
26			
27	415-421.1	Other Income	
28	421.2-426.5	Other Deductions	
29			
30		**NET INCOME**	(49,414)
31			
32		Customers (Intrastate Only)	
33			
34		Year End Average:	
35		Residential	8
36		*Commercial*	1
37		Industrial	
38		Other	10
39			
40		**TOTAL NUMBER OF CUSTOMERS**	19
41			
42		Other Statistics (Intrastate Only)	
43			
44		Average Annual Residential Use (Kwh))	15,000
45		Average Annual Residential Cost per (Kwh) (Cents) *	4.62
46		* Avg annual cost = [(cost per Kwh x annual use) + (mo. svc chrg x 12)]/annual use	
47		Average Residential Monthly Bill	57.74
48		Gross Plant per Customer	66,356

MONTANA CUSTOMER INFORMATION

Year: 2009

	City/Town	Population (Include Rural)	Residential Customers	Commercial Customers	Industrial & Other Customers	Total Customers
1						
2	Noxon, Montana		8	1	10	19
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32	**TOTAL Montana Customers**		8	1	10	19

Company Name: **Avista Corporation** **SCHEDULE 30**

MONTANA EMPLOYEE COUNTS

Year: 2009

	Department	Year Beginning	Year End	Average
1				
2	Noxon Generating Station	27	29	28
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45				
46				
47				
48				
49				
50	**TOTAL Montana Employees**	27	29	28

Company Name: **Avista Corporation** **SCHEDULE 31**

MONTANA CONSTRUCTION BUDGET (ASSIGNED & ALLOCATED) Year: 2009

	Project Description	Total Company	Total Montana
1			
2	Noxon Rapids Capital Projects Upgrades	6,720,448	6,720,448
3			
4	Clark Fork Improvement	4,388,527	4,388,527
5			
6			
7			
8			
9			
10			
11			
12			
13			
14			
15			
16			
17			
18			
19			
20			
21			
22			
23			
24			
25			
26			
27			
28			
29			
30			
31			
32			
33			
34			
35			
36			
37			
38			
39			
40			
41			
42			
43			
44			
45			
46			
47			
48			
49			
50	**TOTAL**	11,108,975	11,108,975

Company Name: Avista Corporation

TOTAL SYSTEM & MONTANA PEAK AND ENERGY

Year: 2009

System

		Peak Day of Month	Peak Hour	Peak Day Volumes Megawatts	Total Monthly Volumes Energy (Mwh)	Non-Requirements Sales For Resale (Mwh)
1	Jan.	26	800	1678	1,337,102	389,676
2	Feb.	10	800	1429	1,209,567	410,926
3	Mar.	11	800	1585	1,261,417	426,800
4	Apr.	1	1100	1295	1,073,235	364,901
5	May	29	1600	1258	1,176,173	466,079
6	Jun.	4	1800	1296	1,139,301	433,851
7	Jul.	27	1700	1502	1,300,754	513,784
8	Aug.	3	1700	1522	1,144,958	375,374
9	Sep.	2	1700	1451	1,050,008	350,481
10	Oct.	12	1700	1332	1,037,430	279,674
11	Nov.	30	800	1400	1,192,235	484,229
12	Dec.	8	800	1763	1,314,127	241,288
13	TOTAL				14,236,307	4,737,063

Montana

		Peak Day of Month	Peak Hour	Peak Day Volumes Megawatts	Total Monthly Volumes Energy (Mwh)	Non-Requirements Sales For Resale (Mwh)
14	Jan.					
15	Feb.					
16	Mar.		Information is not available by state			
17	Apr.					
18	May					
19	Jun.					
20	Jul.					
21	Aug.					
22	Sep.					
23	Oct.					
24	Nov.					
25	Dec.					
26	TOTAL					

TOTAL SYSTEM Sources & Disposition of Energy

	Sources	Megawatthours	Disposition	Megawatthours
1	Generation (Net of Station Use)			
2	Steam	1,460,783	Sales to Ultimate Consumers	
3	Nuclear		(Include Interdepartmental)	8,954,984
4	Hydro - Conventional	3,765,761		
5	Hydro - Pumped Storage		Requirements Sales	
6	Other	1,636,707	for Resale	4,737,063
7	(Less) Energy for Pumping			
8	**NET Generation**	6,863,251	Non-Requirements Sales	
9	Purchases	7,373,956	for Resale	
10	Power Exchanges			
11	Received	688,110	Energy Furnished	
12	Delivered	(689,010)	Without Charge	
13	**NET Exchanges**	(900)		
14	Transmission Wheeling for Others		Energy Used Within	
15	Received		Electric Utility	11,925
16	Delivered			
17	**NET Transmission Wheeling**		Total Energy Losses	532,335
18	Transmission by Others Losses			
19	**TOTAL**	14,236,307	**TOTAL**	14,236,307

SOURCES OF ELECTRIC SUPPLY

Year: 2009

	Type	Plant Name	Location	Annual Peak (MW)	Annual Energy (Mwh)
1					
2	Washington:				
3					
4	Thermal	Kettle Falls	Kettle Falls, WA	50	183,407
5	Hydro	Little Falls	Ford, WA	37	199,278
6	Hydro	Long Lake	Ford, WA	90	487,090
7	Hydro	Monroe Street	Spokane, WA	16	103,900
8	Hydro	Nine Mile	Spokane, WA	21	105,851
9	Hydro	Upper Falls	Spokane, WA	11	51,612
10	Combustion -				
11	Turbine	Northeast	Spokane, WA	40	43
12	Combustion -				
13	Turbine	Kettle Falls Bi-fuel	Kettle Falls, WA	8	5,225
14	Combustion -				
15	Turbine	Boulder Park	Spokane, WA	25	27,763
16					
17					
18	Idaho:				
19	Hydro	Cabinet Gorge	Clark Fork, ID	261	1,060,429
20	Hydro	Post Falls	Post Falls, ID	18	84,350
21	Combustion -				
22	Turbine	Rathdrum	Rathdrum, ID	176	44,308
23					
24					
25					
26	Montana:				
27	Thermal	Colstrip #3 and #4	Colstrip, MT	226	1,277,376
28	Hydro	Noxon	Thompson Falls, MT	550	1,673,251
29					
30	Oregon:				
31	Combustion -				
32	Turbine	Coyote Springs 2	Boardman, OR	307	1,559,368
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46					
47					
48					
49	**Total**			1,836	6,863,251

MONTANA CONSERVATION & DEMAND SIDE MANAGEMENT PROGRAMS

Year: 2009

	Program Description	Current Year Expenditures	Last Year Expenditures	% Change	Planned Savings (MW & MWH)	Achieved Savings (MW & MWH)	Difference (MW & MWH)
1							
2							
3	Not applicable						
4							
5							
6							
7							
8							
9							
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
29							
30							
31							
32	TOTAL						

Company Name: Avista Corporation

Schedule 35a

Electric Universal System Benefits Programs

	Program Description	Actual Current Year Expenditures	Contracted or Committed Current Year Expenditures	Total Current Year Expenditures	Expected savings (MW and MWh)	Most recent program evaluation
1	Local Conservation					
2						
3	Avista Corp. does not have any benefit programs in Montana.					
4						
5						
6						
7						
8	Market Transformation					
9						
10						
11						
12						
13						
14						
15	Renewable Resources					
16						
17						
18						
19						
20						
21						
22	Research & Development					
23						
24						
25						
26						
27						
28						
29	Low Income					
30						
31						
32						
33						
34						
35	Large Customer Self Directed					
36						
37						
38						
39						
40						
41						
42	Total					
43	Number of customers that received low income rate discounts					
44	Average monthly bill discount amount ($/mo)					
45	Average LIEAP-eligible household income					
46	Number of customers that received weatherization assistance					
47	Expected average annual bill savings from weatherization					
48	Number of residential audits performed					

Company Name: Avista Corporation

Schedule 35b

Montana Conservation & Demand Side Management Programs

	Program Description	Actual Current Year Expenditures	Contracted or Committed Current Year Expenditures	Total Current Year Expenditures	Expected savings (MW and MWh)	Most recent program evaluation
1	Local Conservation					
2						
3	Avista Corp. does not have any conservation & demand side management programs in Montana.					
4						
5						
6						
7						
8	Demand Response					
9						
10						
11						
12						
13						
14						
15	Market Transformation					
16						
17						
18						
19						
20						
21						
22	Research & Development					
23						
24						
25						
26						
27						
28						
29	Low Income					
30						
31						
32						
33						
34						
35	Other					
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46	Total					

Company Name: Avista Corporation SCHEDULE 36

MONTANA CONSUMPTION AND REVENUES

Year: 2009

	Sales of Electricity	Operating Revenues Current Year	Operating Revenues Previous Year	MegaWatt Hours Sold Current Year	MegaWatt Hours Sold Previous Year	Avg. No. of Customers Current Year	Avg. No. of Customers Previous Year
1	Residential	$5,543	$5,994	120	132	8	10
2	Commercial - Small	1,477	1,932	23	30	1	1
3	Commercial - Large						
4	Industrial - Small						
5	Industrial - Large						
6	Interruptible Industrial						
7	Public Street & Highway Lighting						
8	Other Sales to Public Authorities						
9	Sales to Cooperatives						
10	Sales to Other Utilities						
11	Interdepartmental	26,292	18,122	407	275	10	8
12							
13	**TOTAL**	$33,312	$26,048	550	437	19	19